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): May 28, 2015

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**

(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 8.01. Other Events.

On February 17, 2015, EnLink Midstream Partners, LP (the “Partnership”) acquired a 25% limited partner interest (the “February Transferred Interests”) in EnLink Midstream Holdings, LP (“Midstream Holdings”) from Acacia Natural Gas Corp I, Inc. (“Acacia”), a wholly-owned subsidiary of EnLink Midstream, LLC (“ENLC”), in a drop-down transaction (the “February EMH Drop Down”). As consideration for the February Transferred Interests, the Partnership issued 31.6 million Class D Common Units in the Partnership to Acacia. On May 27, 2015, the Partnership acquired the remaining 25% limited partner interest in Midstream Holdings (the “May Transferred Interests” and, together with the February Transferred Interests the "Transferred Interests") from Acacia in a drop-down transaction (the "May EMH Drop Down" and, together with the February EMH Drop Down, the "EMH Drop Downs") in exchange for 36.6 million Class E Common Units in the Partnership. After giving effect to the EMH Drop Downs, the Partnership owns 100% of Midstream Holdings.

On April 1, 2015, the Partnership acquired from Devon Gas Services, L.P. (“DGS”), a subsidiary of Devon Energy Corporation (i) all of the equity interests in Victoria Express Pipeline, L.L.C., a Texas limited liability company (“VEX”), which operates a 56-mile petroleum condensate pipeline and (ii) certain crude petroleum and petroleum condensate truck unloading, transportation, terminalling and barge loading assets (collectively, the “ VEX Interests”) located in the Eagle Ford shale in south Texas. The aggregate consideration paid by the Partnership to DGS for the VEX Interests consisted of $171.0 million in cash, 338,159 common units representing limited partner interests in the Partnership with an aggregate value of approximately $9.0 million and the Partnership’s assumption of up to $40.0 million in certain construction costs related to the VEX Interests, subject to certain adjustments.

Due to ENLC's control of the Partnership through its ownership and control of EnLink Midstream GP, LLC (“General Partner”), the general partner of the Partnership, and Devon's control of the Partnership through its ownership of the managing member of ENLC, the acquisition of the Transferred Interests and VEX Interests is considered a transfer of net assets between entities under common control. As such, the Partnership is required to recast its financial statements to include the activities of the Transferred Interests and VEX Interests as of the date common control commenced. Exhibits 12.1, 99.1, 99.2, 99.3 and 99.4 included in this Current Report on Form 8-K give retroactive effect to the acquisition of the Transferred Interests and VEX Interests as if the Partnership owned the Transferred Interests and VEX Interests effective as of March 7, 2014.

The Partnership’s Annual Report on Form 10-K for the year ended December 31, 2014 (the “2014 Form 10-K”), as filed with the Securities and Exchange Commission (the “SEC”) on February 20, 2015, as recast by the Partnership's Current Report on Form 8-K on February 20, 2015, is hereby again recast by this Current Report on Form 8-K as follows:

- the Computation of Ratio of Earnings to Fixed Charges of the Partnership included herein on Exhibit 12.1 supersedes Exhibit 12.1 filed under Part IV, Item 15 of the 2014 Form 10-K;
- the Business of the Partnership included herein in Exhibit 99.1 supersedes Part I, Item 1 of the 2014 Form 10-K;
- the Selected Financial Data of the Partnership included herein in Exhibit 99.2 supersedes Part II, Item 6 of the 2014 Form 10-K;
- the Management’s Discussion and Analysis of Financial Condition and Results of Operations of the Partnership included herein in Exhibit 99.3 supersedes Part II, Item 7 of the 2014 Form 10-K; and
- the Financial Statements and Supplementary Data of the Partnership included herein in Exhibit 99.4 supersedes Part II, Item 8 of the 2014 Form 10-K, except for the Management’s Report on Internal Control over Financial Reporting and the Report of Independent Registered Public Accounting Firm with regard to internal control over financial reporting, included at page F-2 and F-3 of the 2014 Form 10-K, respectively, which are not impacted by this Current Report on Form 8-K.

This Current Report on Form 8-K does not revise or update any section of the 2014 Form 10-K other than as noted above. This Current Report on Form 8-K should be read in conjunction with the 2014 Form 10-K, and any references herein to Items 1 under Part 1 and Items 6, 7 and 8 under Part II of the 2014 Form 10-K refer to Exhibits 99.1, 99.2, 99.3 and 99.4 hereto, respectively. As of the date of this Current Report on Form 8-K, future references to the Partnership’s historical financial statements should be made to this Current Report on Form 8-K as well as future quarterly and annual reports on Forms 10-Q and Forms 10-K, respectively.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits.*

EXHIBIT NUMBER		DESCRIPTION
12.1	—	Computation of Ratio of Earnings to Fixed Charges.
23.1	—	Consent of KPMG LLP.
99.1	—	Recast 2014 Form 10-K - Item 1. Business
99.2	—	Recast 2014 Form 10-K - Item 6. Selected Financial Data.
99.3	—	Recast 2014 Form 10-K - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.4	—	Recast 2014 Form 10-K - Item 8. Financial Statements and Supplementary Data.
101.INS	—	XBRL Instance Document.
101.SCH	—	XBRL Schema Document.
101.CAL	—	XBRL Calculation Linkbase Document.
101.LAB	—	XBRL Label Document.
101.PRE	—	XBRL Presentation Linkbase Document.
101.DEF	—	XBRL Definition Linkbase Document.

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: May 28, 2015

By: /s/ Michael J. Garberding

Michael J. Garberding
Executive Vice President and
Chief Financial Officer

INDEX TO EXHIBITS

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Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions)				
Earnings Before Fixed charges:					
Earnings from continuing operations before non-controlling interest or tax	$ 331.3	$ 186.1	$ 128.3	$ 311.4	$ 232.0
Capitalized interest	(11.8)	—	—	—	—
Amortization of capitalized interest	0.5	—	—	—	—
Income from equity investment	(18.9)	(14.8)	(2.0)	(9.3)	(5.1)
Distributed income from equity investment	23.7	12.0	2.3	8.3	8.7
Non-controlling interest	(0.2)	—	—	—	—
Total earnings before fixed charges	$ 324.6	$ 183.3	$ 128.6	$ 310.4	$ 235.6
Fixed charges:					
Interest expense includes discontinued operations	$ 47.4	$ —	$ —	$ —	$ —
Capitalized interest includes discontinued operations	11.8	—	—	—	—
Total fixed charges	$ 59.2	$ —	$ —	$ —	$ —
Total earnings & fixed charges	$ 383.8	$ 183.3	$ 128.6	$ 310.4	$ 235.6
Ratio of earnings to fixed charges	6.5	N/A	N/A	N/A	N/A
Deficiency	$ —	$ —	$ —	$ —	$ —

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
EnLink Midstream Partners, LP:

We consent to the incorporation by reference in the registration statements No. 333-107025, 333-127645, 333-159140 and 333-188678 on Forms S-8, No 333-194465 and 333-199618 on Form S-3 of EnLink Midstream Partners, LP and subsidiaries of our report dated May 28, 2015, with respect to the consolidated balance sheets of EnLink Midstream Partners, LP and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2014, which report appears in the Form 8-K of EnLink Midstream Partners, LP and subsidiaries dated May 28, 2015.

Our report refers to a change in the Partnership's method of accounting for computing depreciation on certain assets.

/s/ KPMG LLP

Dallas, Texas
May 28, 2015

Exhibit 99.1

Item 1. *Business*

General

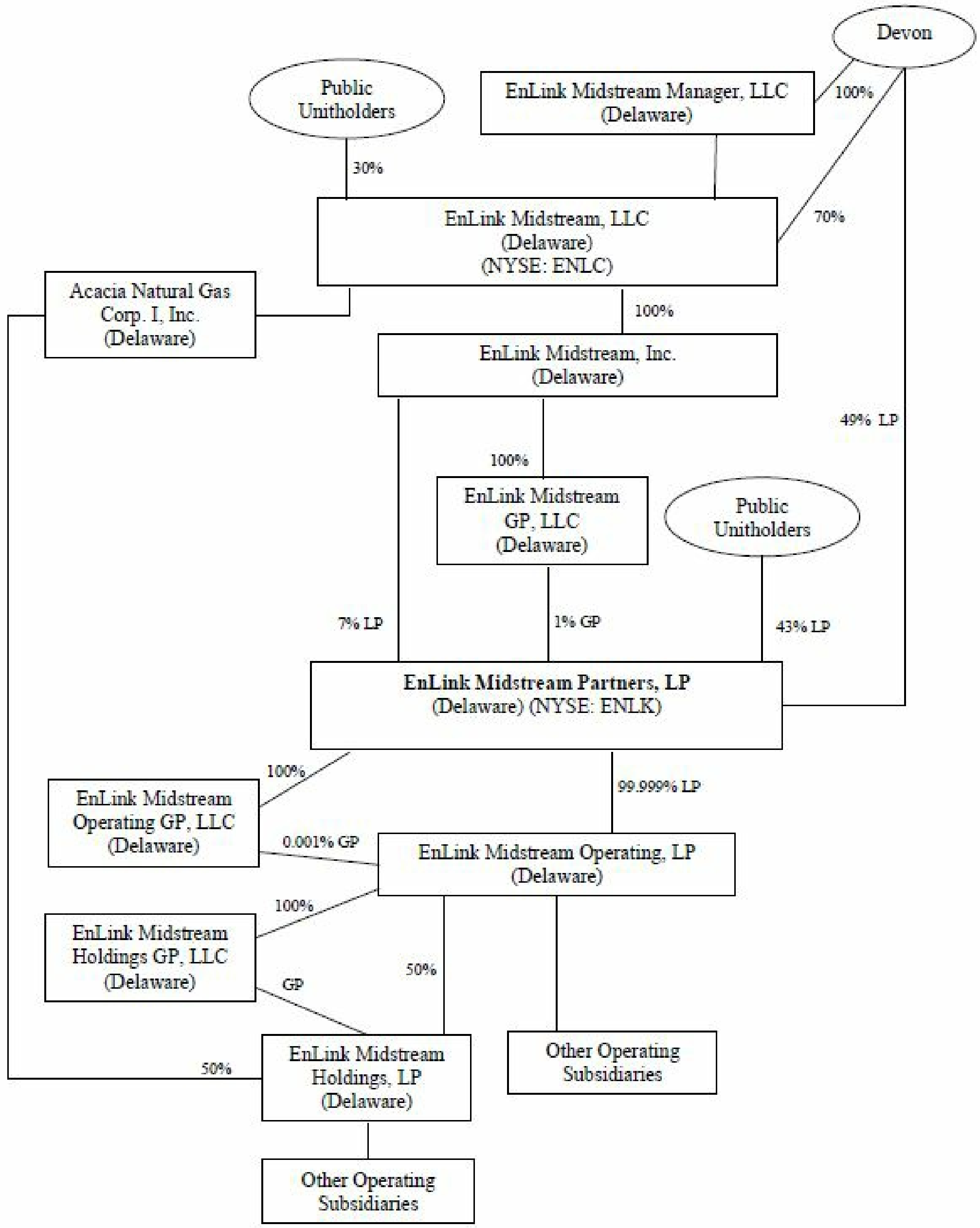
EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange (“NYSE”) under the symbol “ENLK.” Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited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

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner (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” or “EnLink Midstream”). ENLC’s units are traded on the NYSE under the symbol “ENLC.” ENLC’s manager is an indirect wholly-owned subsidiary of Devon Energy Corporation (“Devon”).

Effective as of March 7, 2014, the Operating Partnership acquired (the “Acquisition”) 50% of the outstanding equity interests in EnLink Midstream Holdings, LP (“Midstream Holdings”) and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership. At the same time, EnLink Midstream, Inc. (“EMI”), the entity that directly owns our General Partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the “business combination”). At the conclusion of the business combination, another wholly-owned subsidiary of ENLC, Acacia Natural Gas Corp. I, Inc. (“Acacia”), owned the remaining 50% of the outstanding equity interests in Midstream Holdings. On February 17, 2015, Acacia contributed a 25% interest in Midstream Holdings (the “February Transferred Interests”) to us in exchange for 31.6 million Class D Common Units in the Partnership in a drop down transaction (the "February EMH Drop Down"). On May 27, 2015, the Partnership acquired the remaining 25% limited partner interest in Midstream Holdings (the “ May Transferred Interests” and, together with the February Transferred Interests, the "Transferred Interests") from Acacia in a drop-down transaction in exchange for 36.6 million Class E Common Units in us in a drop down transaction (the "May EMH Drop Down" and, together with the February Drop Down, the "EMH Drop Downs"). After giving effect to the EMH Drop-Downs, the Partnership owns 100% of 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. On April 1, 2015, the Partnership acquired the Victoria Express Pipeline and related truck and terminal storage assets ("VEX") from Devon (the "VEX Interests"). See “Recent Growth Developments.”

Midstream Holdings was formerly a wholly-owned subsidiary of Devon Energy Corporation (“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 as of December 31, 2014 (does not reflect EMH Drop Downs).



Definitions

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

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

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

Our Operations

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing, to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 8,900 miles of pipelines, 13 natural gas processing plants, seven fractionators, 3.1 million barrels of NGL cavern storage, 11 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. Our operations are based in the United States and our sales are derived from external domestic customers.

We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee-based arrangements. We provide a variety of crude oil and condensate services, which include crude oil and condensate gathering via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. 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 from our south Louisiana processing plants to our fractionators in south Louisiana. Additionally, we own an economic interest in an NGL fractionator located at Mont Belvieu, Texas that receives raw mix NGLs from customers, fractionates such raw mix and redelivers the finished products to the customers for a fee. Devon is one of the largest customers of this fractionator. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport oil from a producer site to an end user. Our processing plants remove NGLs and CO2 from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

Our assets are 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 own a 100% interest as of May 27, 2015, 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 1.2 Bcf/d and gathering systems with total capacity of approximately 2.8 Bcf/d.

- *Oklahoma.* Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 MMcf/d.
- *Louisiana.* Our Louisiana assets consist of transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.
- *Ohio River Valley.* Our Ohio River Valley ("ORV") operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot 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 5,000 Bbls/d. Additionally, our ORV operations include five condensate stabilization and natural gas compression stations, including two stations under construction, with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression.

About Devon

Devon (NYSE: DVN) is a leading independent energy company engaged primarily in the exploration, development and production of crude oil, natural gas and NGLs. Devon's operations are concentrated in various onshore areas in the U.S. and Canada. Please see Devon's Annual Report on Form 10-K for the year ended December 31, 2014 for additional information concerning Devon's business.

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 whether to pursue economically attractive organic expansion opportunities in existing or new areas of operation that allow us to leverage our existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for our services.
- *Growing with Devon*: We expect our relationship with Devon will continue to provide us with significant business opportunities. Devon is a leading North American E&P company with a focus on five core growth areas: Eagle Ford, Permian Basin, Anadarko Basin, Canadian oil sands and the Barnett Shale.
- *Dropdowns: maximize opportunities provided by Devon's sponsorship and assets held by ENLC.* We plan to execute our growth in part through continued pursuit of accretive drop down opportunities from Devon and ENLC. In the first half of 2015, we acquired the Transferred Interests in Midstream Holdings from ENLC and acquired the Victoria Express Pipeline and related truck terminal and storage assets from Devon (the "VEX Interests") as described in Note (3)-Acquisitions. ENLC and Devon are parties to a first offer agreement pursuant to which ENLC has a right of first offer with respect to Devon's 50% interest in the Access Pipeline (the "First Offer Agreement"). We are party to a preferential rights agreement with ENLC pursuant to which ENLC granted us a right of first refusal, for a period of 10 years, with respect to Devon's 50% interest in the Access Pipeline transportation system, to the extent ENLC in the future obtains such interest pursuant to the First Offer Agreement. In addition, if ENLC has the opportunity to exercise its right of first offer for Devon's interest in the Access Pipeline pursuant to the First Offer Agreement, but determines not to exercise such right, ENLC is required to assign such right to us. 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 other key financial metrics 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 49% ownership interest in us as of December 31, 2014.

- *Strategically-located assets*. Our assets are strategically located in strategic producing regions with the potential for increasing throughput volume and cash flow generation. Our assets are in areas consistent with Devon's strategic focus. Our asset portfolio includes gathering, transmission, fractionation, processing and stabilization systems that are located in areas in which producer activity is focused on crude oil, condensate and NGLs as well as natural gas. We have developed or are in the process of developing platforms in these areas through organic development and acquisitions.

- *Stable cash flows*. Approximately 95% of our cash flows were derived from fee-based services with no direct commodity exposure during 2014. 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 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 and Cana-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 "Item 1A. Risk Factors" of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K") filed with the Securities and Exchange Commission ("SEC") on February 20, 2015.

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 (2)	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.

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

Recent Growth Developments

Organic Growth

Ohio River Valley Condensate Pipeline and Condensate Stabilization Facilities. In August 2014, we announced plans to construct a new 45-mile, eight-inch condensate pipeline and six natural gas compression and condensate stabilization facilities that will service major producer customers in the Utica Shale, including Eclipse Resources. As a component of the project, the Partnership has entered into a long-term, fee-based agreement under which Eclipse Resources will receive compression and stabilization services and has agreed to sell stabilized condensate to us.

The new-build stabilized condensate pipeline will connect to our existing 200-mile pipeline in the ORV, providing producer customers in the region access to premium market outlets through our barge facility on the Ohio River and rail terminal in Ohio. The pipeline, which is expected to be complete in the second half of 2015, is expected to have an initial capacity of approximately 50,000 Bbls/d with potential to expand.

We will also build and operate six natural gas compression and condensate stabilization facilities in Noble, Belmont, and Guernsey counties in Ohio. Upon completion, the facilities will have a combined capacity of approximately 560 MMcf/d of natural gas compression and approximately 41,500 Bbls/d of condensate stabilization. The first two compression and condensate stabilization facilities began operations during the fourth quarter of 2014 and the remaining four facilities are expected to be operational by the end of 2015.

In support of the project, we plan to leverage and expand our existing midstream assets in the region, including increasing condensate storage capacity and handling capabilities at our barge terminal on the Ohio River. We will add approximately 130,000 barrels of above ground storage, bringing our total storage capacity at the barge facility to over 360,000 barrels.

Marathon Petroleum Joint Venture. We have entered into a series of agreements with a subsidiary of Marathon Petroleum Corporation ("Marathon Petroleum"), to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will build a new 30-mile NGL pipeline connecting our existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. The bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, we will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Cajun-Sibon Phases I and II. In Louisiana, we have transformed our business that historically has been focused on processing offshore natural gas to a business that is now 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 now 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.

The pipeline expansion and the Eunice fractionation expansion under Phase I were completed and commenced operation in November 2013. Phase II of the Cajun-Sibon expansion, which was completed and commenced operation in September 2014, increased the Cajun-Sibon pipeline capacity by an additional 50,000 Bbls/d to approximately 130,000 Bbls/d and added a new 100,000 Bbl/d fractionator at our Plaquemine gas processing complex. The throughput of the pipeline averaged 109,900 Bbls/d during the fourth quarter of 2014. Our fractionators in south Louisiana averaged approximately 98,300 Bbls/d during the fourth quarter of 2014.

We believe the Cajun-Sibon project represents a tremendous growth step by leveraging our Louisiana assets and also by creating 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 September 2014, we completed construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin called Bearkat. The natural gas processing complex includes treating, processing and gas takeaway solutions for regional producers. The project, which is fully owned by us, is supported by a 10-year, fee-based contract.

Bearkat is strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant has an initial capacity of 60 MMcf/d, increasing our total operational processing capacity in the Permian to approximately 115 MMcf/d. We also completed construction of a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan counties.

During 2014, we constructed a new 35-mile, 12-inch diameter high-pressure pipeline to provide gathering capacity for the Bearkat natural gas processing complex. The pipeline has an initial capacity of approximately 100 MMcf/d and provides gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The pipeline commenced operation in the fourth quarter of 2014.

Growing with Devon

West Texas Expansion. We are expanding our natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing plant and expanding our rich gas gathering system. The new 120 MMcf/d gas processing plant will be strategically located on the north end of our existing midstream assets and will offer additional gas processing capabilities to producer customers in the region, including Devon. Due to the impact from the current commodity environment and a shift in producers' drilling expectations, we are delaying construction on the processing plant until late 2015. Upon completion, our total operated processing capacity in the region will be approximately 240 MMcf/d.

As a part of the expansion, we are a party to a long-term, fee-based agreement with Devon to provide gathering and processing services for over 18,000 acres under development in Martin County. We constructed multiple low pressure gathering pipelines and a new 23-mile, 12-inch high pressure gathering pipeline that will tie into the Bearkat natural gas gathering system. The new pipelines commenced operation in January 2015.

Drop Downs

Midstream Holdings Drop Down. On February 17, 2015, the Partnership acquired the February Transferred Interests from Acacia in the February EMH Drop Down. As consideration for the February Transferred Interests, the Partnership issued 31.6 million Class D Common Units in the Partnership to Acacia.

On May 27, 2015, the Partnership acquired the May Transferred Interests from Acacia in the May EMH Drop Down. As consideration for the May Transferred Interests, the Partnership issued 36.6 million Class E Common Units in the Partnership to Acacia. After giving effect to the EMH Drop-Downs, the Partnership owns 100% of Midstream Holdings.

VEX Pipeline. On April 1, 2015, the Partnership acquired the VEX Interests from Devon, which are located in the Eagle Ford shale in south Texas. The aggregate consideration paid by the Partnership consisted of $171.0 million in cash, 338,159 common units representing limited partner interests in the Partnership with an aggregate value of approximately $9.0 million and the Partnership's assumption of up to $40.0 million in certain construction costs related to VEX. The VEX pipeline is a 56-mile multi-grade crude oil pipeline with a current capacity of approximately 50,000 Bbls/d and, following completion of currently-underway expansion projects, will have capacity of approximately 90,000 Bbls/d. Other VEX assets at the destination of the pipeline include an eight-bay truck unloading terminal, 200,000 barrels of above-ground storage, of which 50,000 barrels are under construction, and rights to barge loading docks.

E2 Drop Down. On October 22, 2014, the Partnership acquired from EMI, a wholly-owned subsidiary of ENLC, 100% of the Class A Units and 50% of the Class B Units (collectively, the "E2 Appalachian Units") in E2 Appalachian Compression, LLC ("E2 Appalachian"), and 93.7% of the Class A Units (the "Energy Services Units" and, together with the E2 Appalachian Units, the "Purchased Units") in E2 Energy Services, LLC ("Energy Services" and, together with E2 Appalachian, "E2"). The total consideration paid by the Partnership to EMI for the Purchased Units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in the Partnership for the E2 Appalachian Units. The remaining 50% of the Class B Units in E2 Appalachian are owned by members of the E2 Appalachian management team and are designed to provide such management team members with equity incentives.

E2’s assets include five condensate stabilization and natural gas compression stations with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression located in the ORV. Currently, three of the five stations are in service and commercial start-up of the two remaining stations is expected in the first half of 2015. The assets are supported by a long-term, fee-based contract with Antero Resources.

Acquisitions

Coronado Midstream. On February 1, 2015, the Partnership entered into an agreement with Reliance Midstream, LLC, a Texas limited liability company (“Reliance”), Windsor Midstream LLC, a Delaware limited liability company (“Windsor”), Wallace Family Partnership, LP, a Texas limited partnership (“Wallace”), and Ted Collins, Jr., an individual residing in Midland, Texas (“Collins” and, collectively with Reliance, Windsor and Wallace, the “Sellers,” and each, a “Seller”), and Reliance, in its capacity as representative of the Sellers, to acquire all of the equity interests in Coronado Midstream Holdings LLC, the parent company of Coronado Midstream LLC (“Coronado”), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.0 million in cash and equity, subject to certain adjustments. Coronado operates three cryogenic gas processing plants and a gas gathering system in the North Midland Basin including approximately 270 miles of gathering pipelines, 175 MMcf/d of processing capacity and 35,000 horsepower of compression. The Coronado system is underpinned by long-term contracts, which include the dedication of production from over 190,000 acres.

LPC Crude Oil Marketing. On January 31, 2015, the Partnership, through one of its wholly owned subsidiaries, acquired LPC Crude Oil Marketing LLC (“LPC”), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $100.0 million. LPC is an integrated crude oil logistics service provider with operations throughout the Permian Basin. LPC's integrated logistics services are supported by 41 tractor trailers, 13 pipeline injection stations and 67 miles of crude oil gathering pipeline.

Natural Gas Pipeline Assets. On November 1, 2014, we acquired from affiliates of Chevron Corporation certain Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana for $234.0 million, subject to certain adjustments. These natural gas pipeline assets include the following:

- *Bridgeline System:* approximately 990 miles of natural gas pipelines in southern Louisiana with a total system capacity of approximately 900 MMcf/d;
- *Sabine Pipeline:* approximately 130 miles of natural gas pipelines in Texas and southern Louisiana with a total capacity of approximately 300 MMcf/d;
- *Chandeleur System*: approximately 215 miles of offshore Mississippi and Alabama pipelines with a total capacity of approximately 300 MMcf/d;
- *Storage Assets:* three caverns located in southern Louisiana with a combined working capacity of approximately 11 Bcf of natural gas, including two near Sorrento, LA with a capacity of approximately 4.0 Bcf and one inactive cavern near Napoleonville, LA with a capacity of approximately 7.0 Bcf; and
- *Henry Hub:* ownership and management of the title tracking services offered at the Henry Hub, the delivery location for the New York Mercantile Exchange (the “NYMEX”) natural gas futures contracts. Henry Hub is connected to 13 major interstate and intrastate natural gas pipeline and storage systems.

Our Assets

Our assets consist of gathering systems, transmission pipelines, processing facilities, fractionation facilities, stabilization facilities, storage facilities and ancillary assets. Except as stated otherwise, the following tables provide information about our assets as of and for the year ended December 31, 2014:

			Year Ended December 31, 2014	
Gathering and Transmission Pipelines	**Approximate Length (Miles)**	**Compression (1) (HP)**	**Estimated Capacity (MMcf/d)**	**Average Throughput (Thousands of MMBtu/d)**
Texas Assets:				
Partnership Assets ^	895	131,834	1,715	958,300
Midstream Holdings Assets*	3,267	262,000	2,330	1,999,600
Oklahoma Assets:				
Cana System*	340	87,499	530	414,000
Northridge System*	140	17,895	75	57,000
Louisiana Assets:				
LIG System^ (2)	3,320	78,648	3,975	615,000
South Louisiana Assets^	600	—	— (3)	— (4)
VEX Assets:				
VEX Assets	56	—	— (5)	— (6)
Total	8,618	577,876	8,625	4,043,900

^ Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which the Partnership held a 50% interest as of December 31, 2014 and 100% interest as of May 27, 2015.

(1) Includes power generation units.

(2) Includes natural gas pipelines acquired from Chevron Corporation on November 1, 2014. Average throughput volumes reflect throughput for the period from November 1, 2014 through December 31, 2014.

(3) Our South Louisiana assets also have estimated capacity for liquid pipeline transportation of approximately 130 MBbls/d.

(4) Our South Louisiana Cajun-Sibon liquids pipeline, including the Cajun-Sibon II expansion which commenced operations in late September 2014, had an average throughput of 72,900 Bbls/d for the year ended December 31, 2014.

(5) Our VEX assets have an estimated capacity for crude pipeline transportation of approximately 50 MBbls/d.

(6) Our VEX crude pipeline, which commenced operations in July 2014, had an average throughput of 19,800 Bbls/d for the period from July 1, 2014 through December 31, 2014.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2014 Average Throughput (MMBtu/d)
Texas Assets		
Partnership Assets^	369	357,100
Midstream Holdings Assets*	790	788,700
Oklahoma Assets		
Cana System*	350	368,400
Northridge System*	200	73,400
Louisiana Assets		
LIG Assets^	335	193,400
South Louisiana Assets^	1,375	354,000
Total	3,419	2,135,000

^ Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which the Partnership held a 50% interest as of December 31, 2014 and an 100% interest as of May 27, 2015.

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^	183	116	
Gulf Coast Fractionators (1)	56	44	
Total	280	165	

^ Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which the Partnership held a 50% interest as of December 31, 2014 and an 100% interest as of May 27, 2015.

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

(2) We are in the process of connecting our Texas fractionation facility 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 will provide operational flexibility for the related processing plants, but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under the Partnership's current contracts, it does not earn fractionation fees for operating these fractionation facilities so throughput volumes through these facilities are not captured on a routine basis and are not significant to its operating margins.

Texas Assets. 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 100% interest as of May 27, 2015, and include transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.2 Bcf/d and gathering systems with total capacity of approximately 2.8 Bcf/d.

- *Transmission Systems.* Our transmission systems in Texas include approximately 260 miles of pipeline with an aggregate capacity of approximately 1.3 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 period March 7, 2014 through December 31, 2014, the average throughput on the NTPL was approximately 338,000 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, 2014, average throughput was approximately 733,900 MMBtu/d. Devon is the Acacia transmission system’s only customer and has entered into a 10-year fixed-fee transportation agreement that covers transmission services on the Acacia transmission pipeline and includes annual rate escalators.

- *Processing and Fractionation Facilities.* Our processing facilities in Texas include six gas processing plants with total processing throughput that averaged 1,145,749 MMBtu/d for the year ended December 31, 2014 and our 38.75% interest in GCF 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 a total of 790 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity, respectively. For the year ended December 31, 2014, throughput volumes at the Bridgeport processing facility averaged 788,700 MMBtu/d of natural gas. Devon is the Bridgeport facility’s largest customer with approximately 717,700 MMBtu/d of natural gas processed for the year ended December 31, 2014, which represented approximately 91% of the total volumes processed at the facility during such period. In March 2014, Devon and Midstream Holdings entered into a 10-year, fixed-fee processing agreement pursuant to which Midstream Holdings provides 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*. The Partnership’s Silver Creek processing complex, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants. The Partnership’s Silver Creek plants have a total of 280 MMcf/d of processing capacity, with the Azle Plant, Silver Creek Plant and Goforth Plant accounting for 50 MMcf/d, 200 MMcf/d and 30 MMCf/d of processing capacity, respectively. For the period March 7, 2014 through December 31, 2014, throughput volumes at the Silver Creek processing facility averaged 283,600 MMBtu/d of natural gas.

    - *Permian Basin assets*. Our Permian Basin assets consist of our Deadwood natural gas processing plant, our Bearkat natural gas processing plant and gathering facilities, and our Mesquite Terminal fractionator. The Partnership has 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 71,000 MMBtu/d for the period March 7, 2014 through December 31, 2014. 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. The Bearkat facility came online in the third quarter of 2014 and consists of a natural gas processing plant with condensate stabilization. The Bearkat plant has a total capacity of 60MMcf/d, and is supplied from approximately 90 miles of high pressure gathering pipelines and 6 compressor stations. The high pressure gathering system has a capacity of approximately 240 MMcf/d. The Bearkat plant averaged 3,000 MMBtu/d for December 2014 which was the first full month of operations.

    - *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. The plant fractionated 44,000 Bbls/d of liquids during 2014.

- *Gathering Systems.* Our gathering systems in Texas include approximately 3,902 miles of pipeline with total throughput of approximately 1,886,000 MMBtu/d for the year ended December 31, 2014 and consist of the following:

    - *Bridgeport rich gathering system.* This rich natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 1,922 miles of pipeline segments with approximately 145,000 horsepower of compression. A substantial majority of the natural gas gathered on the system is delivered to the Bridgeport processing facility. For the year ended December 31, 2014, throughput volumes on the Bridgeport rich gathering system averaged 826,300 MMBtu/d of natural gas. Devon is the largest customer on the Bridgeport rich gathering system with approximately 751,900 MMBtu/d of natural gas gathered for the year ended December 31, 2014, which represented approximately 91% 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 agreement pursuant to which Midstream Holdings provides 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 935 miles of pipeline segments with approximately 59,000 horsepower of compression. Natural gas gathered on this system is delivered to the Acacia transmission system and intrastate pipelines without processing. For the year ended December 31, 2014, throughput volumes on the Bridgeport lean gathering system averaged 245,900 MMBtu/d of natural gas. Devon is the largest customer on the Bridgeport lean gathering system with approximately 228,700 MMBtu/d of natural gas gathered for the year ended December 31, 2014, which represented approximately 93% 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 290 miles of pipeline segments. Natural gas gathered on this system is delivered to intrastate pipelines without processing. For the year ended December 31, 2014, throughput volumes on the East Johnson County gathering system averaged 193,500 MMBtu/d of natural gas. Devon is the largest customer on the East Johnson County gathering system with approximately 181,900 MMBtu/d of natural gas gathered for the year ended December 31, 2014, which represented approximately 94% of the total throughput on the system during such period. In March 2014, Devon and Midstream Holdings entered into a 10-year, fixed-fee gathering agreement pursuant to which Midstream Holdings provides 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 system includes two gathering systems. Our north Texas gathering system, which we refer to as NTG, consists of approximately 690 miles of gathering lines with approximately 112,900 horsepower of compression and had an average throughput of approximately 608,700 MMBtu/d for the period March 7, 2014 through December 31, 2014. The Denton system consists of approximately 35 miles of gathering lines and had an average throughput of approximately 11,600 MMBtu/d for the period March 7, 2014 through December 31, 2014.

- *Howard Energy Partners (*"*HEP*"*).* HEP owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas and pursues a growth strategy focused on the needs of south Texas producers. HEP's system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. In addition, HEP has a 10 MBbls/d stabilizer in Live Oak County and a 220 MBbls/d liquids storage terminal near Brownsville, Texas. As of December 31, 2014, 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. Alinda Capital Partners owns a 59% capital interest in HEP.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d, gathering systems with total capacity of approximately 605 MMcf/d and a crude oil and condensate stabilization facility. All of the systems and other assets comprising our Oklahoma assets are owned by Midstream Holdings, in which we own a 100% interest as of May 27, 2015.

- *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, 2014, throughput volumes at the Cana processing facility averaged 368,400 MMBtu/d. The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners and ONEOK Partners. Devon is the primary customer of the Cana processing facilities and has entered into a 10-year, fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings provides 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 340-mile gathering system with approximately 87,500 horsepower of compression. For the year ended December 31, 2014, the Cana system gathered approximately 413,900 MMBtu/d of gas. Devon is the primary customer of the Cana gathering system and, as described above, has entered into a 10-year, fixed-fee gathering agreement with Midstream Holdings pursuant to which Midstream Holdings provides 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 Northridge 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, 2014, throughput volumes at the Northridge processing facility averaged 73,400 MMBtu/d. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MarkWest. In August 2014, Linn Energy acquired certain of Devon's southeastern Oklahoma assets and became the largest customer of the Northridge processing facility. In connection with this acquisition Linn Energy assumed Devon's 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings provides processing services for natural gas delivered 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, 2014, the Northridge system gathered 56,900 MMBtu/d of gas. Linn Energy 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 provides gathering services on the Northridge gathering system. This contract includes a five-year minimum volume commitment from Linn Energy 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 approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.

- *LIG Assets.* The LIG system includes gathering and transmission systems with total capacity of approximately 4.0 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 3,320-mile southern system, which has a capacity in excess of 1.5 Bcf/d and approximately 31,318 horsepower of compression, and the 815-mile northern system, which has a capacity of 465 MMcf/d and approximately 47,330 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. The Partnership's north Louisiana system is connected to its south Louisiana system and has the capacity to move approximately 145 MMcf/d of gas to our markets in the south. The Partnership's LIG gathering system had an average throughput of approximately 449,700 MMbtu/d for the period March 7, 2014 through December 31, 2014.

- The south system also includes two operating, on-system processing plants, the Partnership's Gibson and Plaquemine plants, with 110 MMcf/d and 225 MMcf/d of processing capacity, respectively. For the period March 7, 2014 through December 31, 2014, throughput volumes on the LIG processing system averaged 193,400 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 4,500 Bbls/d for the period March 7, 2014 through December 31, 2014.

- The Gulf Coast gathering and transmission system is comprised of 1,120 miles of onshore systems with a capacity of 1.2 Bcf/d, approximately 37,785 horsepower of compression, underground storage facilities with a storage capacity of 4.2 Bcf of active storage capacity, 7.0 Bcf of inactive storage capacity, and Henry Hub transfer services with a capacity of 2.1 Bcf/d. The onshore system has access to the Gulf Coast and the industrial rich Mississippi River corridor, which is seeing an abundance of new growth in chemical and fertilizer plants. The onshore system had an average throughput of 157,000 MMBtu/d from November 1, 2014 (the date of acquisition) through December 31, 2014. The offshore system is comprised of 215 miles of pipeline with a capacity of 0.3 Bcf/d. The average throughput for the period November 1, 2014 through December 31, 2014 was 8,500 MMBtu/d.

- *South Louisiana NGL and Processing Assets.* Our south Louisiana NGL and natural gas processing assets include approximately 600 miles of liquids transport lines, processing and fractionation assets and underground storage.

  - *Cajun-Sibon Pipeline System.* The Cajun-Sibon pipeline system consists of approximately 600 miles of raw make NGL pipelines with a current system capacity of approximately 130,000 Bbls/d. The pipelines transport unfractionated NGLs, referred to as raw make, from areas such as the Liberty, Texas interconnects near Mont Belvieu and from the Partnership's Eunice and Pelican processing plants in south Louisiana to either the Riverside or Eunice fractionators or to third party fractionators when necessary.

  - *Processing Facilities.* Our processing facilities in south Louisiana include three gas processing plants, of which only one is currently operational, with total processing throughput that averaged 354,000 MMBtu/d for the period March 7, 2014 through December 31, 2014 and two fractionation facilities that averaged 115,500 Bbls/d for the period March 7, 2014 through December 31, 2014.

    - *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 period March 7, 2014 through December 31, 2014, the plant processed approximately 336,000 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 operate and own a 64.29% interest in the Blue Water gas processing plant. The Blue Water plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. The plant has a net capacity with respect to our interest of approximately 300 MMcf/d. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

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

- *Plaquemine Fractionation Facility.* The Plaquemine fractionator is located at our Plaquemine gas processing plant complex and is connected to our Cajun-Sibon pipeline. The Plaquemine fractionation facility has a capacity of approximately 100,000 Bbls/d, and produces purity ethane and propane for sale by pipeline to long-term markets with the butane and heavier products sent to our Riverside facility for further processing. The plant commenced operations during September and fractionated 49,700 Bbls/d during the fourth quarter of 2014.

- *Eunice Fractionation Facility.* The Eunice fractionation facility is located in south central Louisiana. The Eunice fractionation facility has a capacity of 55,000 Bbls/d of liquid products, including ethane, propane, iso-butane, normal butane and natural gasoline, and is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. The plant fractionated 48,600 Bbls/d of liquids for the period March 7, 2014 through December 31, 2014.

- *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 and Pelican processing plants or by third-party truck and rail assets. The Riverside fractionator was converted to a butane-and-heavier facility during 2014 in conjunction with the Cajun-Sibon II project. 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 17,200 Bbls/d for the year ended December 31, 2014. During the periods of full operation at Riverside for 2014 (excluding the 65 days of shut down related to the Cajun-Sibon II project completion), the average throughput was 22,000 Bbls/d.

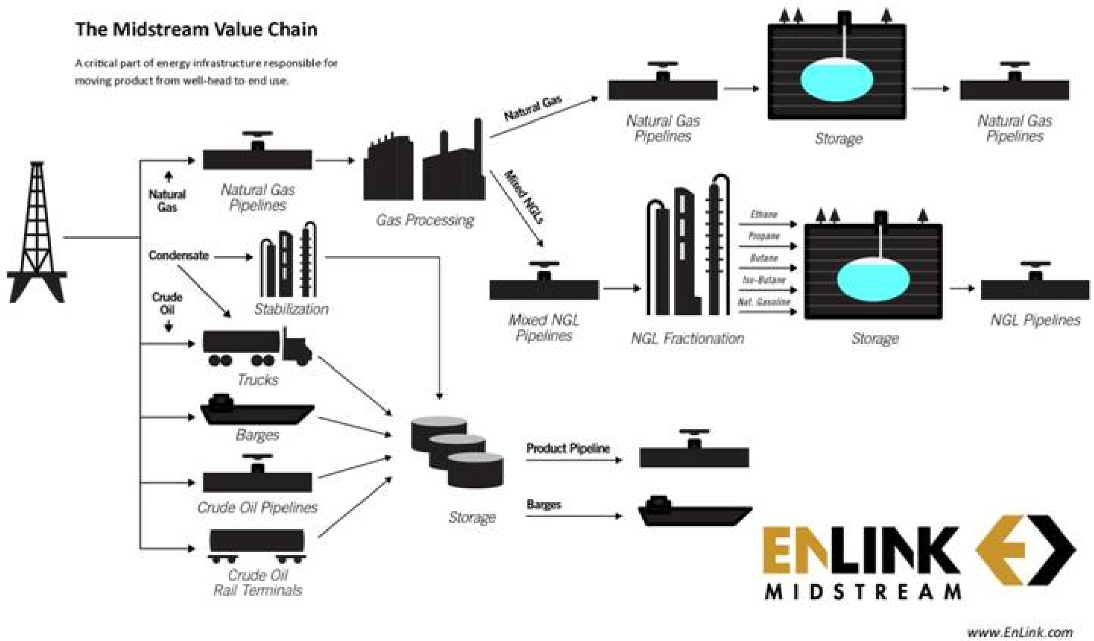
- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of 3.2 million barrels of underground storage comprised of two existing caverns. The caverns are currently operated in butane service, and space is leased to customers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

Ohio River Valley Assets. Our ORV operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 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 16,300 Bbls/d for the year ended December 31, 2014. We have eight existing brine disposal wells with an injection capacity of approximately 5,000 Bbls/d and an average disposal rate of 4,700 Bbls/d for the year ended December 31, 2014. Additionally, our ORV operations consist of five condensate stabilization and natural gas compression stations with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression. Currently, three of the five stations are in service and commercial start-up of the two remaining stations is expected in the first half of 2015. The assets are supported by a long-term, fee-based contract with Antero Resources.

VEX Interests. On April 1, 2015, we acquired the VEX Interests from Devon, which are located in the Eagle Ford shale in south Texas. The VEX pipeline is a 56-mile multi-grade crude oil pipeline with a current capacity of approximately 50,000 Bbls/d and, following completion of currently-underway expansion projects, will have capacity of approximately 90,000 Bbls/d. Other VEX assets at the destination of the pipeline include an eight-bay truck unloading terminal, 200,000 barrels of above-ground storage, of which 50,000 barrels are under construction, and rights to barge loading docks. Also included in the transaction are facilities near the origin of the pipeline that are currently under construction, including an eight-bay truck unloading terminal and 160,000 barrels of above-ground storage. The VEX Interests are included with the Partnership's ORV crude operations for segment reporting for the year ended December 31, 2014.

Industry Overview

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



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

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

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

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

NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream and the removal of contaminants.

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

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

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

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

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

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada. In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium 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 NYMEX related to our natural gas purchases. Through these transactions, we seek to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

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

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

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

Natural Gas, NGL, Crude Oil and Condensate Supply

Our gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which we believe have ample natural gas and NGL supplies in excess of the volumes required for the operation of these systems. Our ORV 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 diligently attempt to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of crude oil, 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 sales price. Therefore, a credit loss can be very large relative to our overall profitability.

For the year ended December 31, 2014, Devon represented 30.6% of our consolidated revenues and Dow Hydrocarbons & Resources LLC represented 11.0% of our consolidated revenues. 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 a substantial portion of their natural gas supply. For the foreseeable future, we expect our profitability to be substantially dependent on Devon. Further, the loss of Dow Hydrocarbons as a customer could have a material impact on our results of operations if we were not able to sell our products to another customer with similar margins because the gross operating margins received from transactions with this customer are material to our total gross operating margin.

Regulation

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

- rates, services, and terms and conditions of service;
- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services;
- the initiation and discontinuation of services;
- internet posting requirements for available capacity, discounts and other matters;
- pipeline segmentation to allow multiple simultaneous shipments under the same contract;
- capacity release to create a secondary market for transportation services;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

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

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

For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. FERC allows regulated companies to recover an allowance for income taxes in rates only to the extent the company or its owners, such as our unitholders, are subject to U.S. income tax. This policy affects whom we allow to own our units, and if we are not successful in limiting ownership of our units to persons or entities subject to U.S. income tax, our FERC-regulated rates and revenues for our interstate natural gas pipelines could be adversely affected.

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

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

Interstate Liquids Pipelines Regulation. We own liquids transportation, storage and other assets in the ORV, 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 is also subject to FERC regulation 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.

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

Intrastate 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 NGL and petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

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

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

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

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

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

Environmental Matters

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

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

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

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

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

We currently own or lease, have in the past owned or leased, and in the future may own or lease, properties that have been used over the years for brine disposal operations, crude oil and condensate transportation, natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other 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, TSCA and analogous state laws. Under these laws, we could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. Our current and future operations are subject to the federal Clean Air Act and 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 a 1.15 to 1 ratio. Devon, Texas industry trade groups and the State of Texas filed petitions for reconsideration with the 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. The EPA has since revised certain aspects of the rules and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such proceedings, the rules may be further modified or rescinded or the EPA may issue new rules. We cannot predict the costs of compliance with any modified or newly issued rules. Additionally, the EPA has signaled its intent to regulate emissions of methane and volatile organic compounds from the oil and gas sector as a measure to implement President Obama’s Climate Action Plan. While the EPA has not yet issued a proposed rulemaking, it has released a series of white papers addressing methane reductions from the oil and gas sector. 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, commonly referred to as “greenhouse gases,” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under existing provisions of the federal Clean Air Act, that establish Prevention of Significant Deterioration ("PSD") pre construction permits, and Title V operating permits for greenhouse gas emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet "best available control technology" standards for their greenhouse gas emissions established by the states or, in some cases, by the EPA on a case by case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities.

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. The EPA and the U.S. Army Corps of Engineers recently proposed a rule to clarify the meaning of the term "waters of the United States." While the practical effects of the proposed rule are ambiguous, many interested parties, including the State of Texas, believe that the proposed rule will expand federal jurisdiction under the Clean Water Act if it is promulgated in its current form as a final rule. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") permits and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

We operate brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act ("SDWA"). The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the 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. However, some state regulatory agencies have modified their regulations to account for induced seismicity. For example, TRRC rules allow the TRRC to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. 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. The EPA has also issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. 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.

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

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

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

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 this pipeline 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. As a result of the sinkhole, it was necessary to permanently remove from service a section of our 36-inch diameter natural gas pipeline. We worked with customers to secure alternative natural gas supplies to minimize disruptions while a replacement pipeline was constructed. The replacement pipeline was completed and services resumed in May 2014. We also implemented additional inspection and operational measures at our nearby underground facility. The damage to our business related to the sinkhole, including costs and loss of business, has been considerable.

We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, LLC (“Texas Brine”), the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, but we have agreed to stay the matter pending resolution of our claims against Texas Brine and its insurers. In August 2014, we received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties. Please read “Item 3. Legal Proceedings.”

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. We also 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, under leases with a wholly-owned subsidiary of Devon which are scheduled to expire in March 2016.

In November 2014, we entered into a new agreement to lease approximately 157,600 square feet of space for our offices in Dallas, Texas with a lease term commencing in June 2016.

Employees

As of December 31, 2014, we (through our subsidiaries) employed approximately 1,152 full-time employees. Approximately 256 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.

Exhibit 99.2

Selected Financial Data

The historical financial statements included in the exhibits to this Current Report on Form 8-K reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to EnLink Midstream Holdings, LP ("Midstream Holdings"), which is the historical predecessor of EnLink Midstream Partners, LP and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream Partners, LP (the "Partnership") after giving effect to the business combination discussed under "Devon Energy Transaction" in Exhibit 99.3 to this Current Report on Form 8-K. The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon Energy Corporation ("Devon") prior to the business combination, including its 38.75% interest in Gulf Coast Fractionators ("GCF"). However, in connection with the business combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

The following table presents the selected historical financial and operating data of the Partnership and the Predecessor for the periods indicated. 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" included in Exhibit 99.3 to this Current Report on Form 8-K and its audited combined financial statements for the year ended December 31, 2014 included in 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 Partnership.

	EnLink Midstream Partners, LP Years Ended December 31,				
	2014 (1)	2013	2012	2011	2010
	(In millions, except per unit data)				
Statement of Operations Data:					
Revenues:					
Revenues	$ 2,412.7	$ 179.4	$ 153.9	$ 13.6	$ 10.9
Revenues-affiliates	1,073.0	2,116.5	1,753.9	2,514.4	1,907.9
Gain on derivatives	22.1	—	—	—	—
Total revenue	3,507.8	2,295.9	1,907.8	2,528.0	1,918.8
Operating costs and expenses:					
Purchased gas, NGLs, condensate and crude oil	2,494.5	1,736.3	1,428.1	1,974.9	1,436.1
Operating expenses	283.6	156.2	149.9	137.1	105.8
General and administrative	94.5	45.1	41.7	38.5	37.6
Depreciation and amortization	284.3	187.0	145.4	133.5	112.2
Gain on sale of property	(0.1)	—	—	—	—
Impairments	—	—	16.4	—	—
Gain on litigation settlement	(6.1)	—	—	—	—
Other expenses	—	—	—	(58.1)	0.2
Total operating costs and expenses	3,150.7	2,124.6	1,781.5	2,225.9	1,691.9
Operating income	357.1	171.3	126.3	302.1	226.9
Other income (expense):					
Interest expense, net of interest income	(47.4)	—	—	—	—
Income from equity investments	18.9	14.8	2.0	9.3	5.1
Gain on extinguishment of debt	3.2	—	—	—	—
Other income (expense)	(0.5)	—	—	—	—
Total other income (expense)	(25.8)	14.8	2.0	9.3	5.1
Income from continuing operations before non-controlling interest and income taxes	331.3	186.1	128.3	311.4	232.0
Income tax provision	(22.0)	(67.0)	(46.2)	(112.1)	(83.5)
Net income from continuing operations	309.3	119.1	82.1	199.3	148.5
Discontinued operations:					
Income (loss) from discontinued operations, net of tax	1.0	(2.3)	(5.2)	18.9	34.8
Income from discontinued operations attributable to non-controlling interest, net of tax	—	(1.3)	(1.1)	(2.1)	(4.6)
Discontinued operations, net of tax	1.0	(3.6)	(6.3)	16.8	30.2
Net income	310.3	115.5	75.8	216.1	178.7
Less: Net loss from continuing operations attributable to the non-controlling interest	(0.2)	—	—	—	—
Net income attributable to EnLink Midstream Partners, LP	$ 310.5	$ 115.5	$ 75.8	$ 216.1	$ 178.7
Predecessor interest in net income	$ 35.5	$ —	$ —	$ —	$ —
General partner interest in net income	$ 138.3	$ —	$ —	$ —	$ —
Limited partners' interest in net income attributable to EnLink Midstream Partners, LP	$ 136.7	$ —	$ —	$ —	$ —
Net income attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic and diluted common unit	$ 0.59	$ —	$ —	$ —	$ —
Distributions declared per limited partner unit	$ 1.47	$ —	$ —	$ —	$ —

	EnLink Midstream Partners, LP Years Ended December 31,				
	2014 (1)	2013	2012	2011	2010
	(In millions, except per unit data)				
Balance Sheet Data (end of period):					
Property and equipment, net	$ 5,042.8	$ 1,768.1	$ 1,739.4	$ 1,550.7	$ 1,439.0
Total assets	8,702.0	2,309.8	2,535.2	2,305.3	2,195.9
Long-term debt (including current maturities)	2,022.5	—	—	—	—
Partners' equity including non-controlling interest	6,025.9	1,783.7	2,002.0	1,901.2	1,849.0

(1) Information has been recast to include results attributable to the 50% limited partner interest in Midstream Holdings (the "Transferred Interests") acquired by the Partnership from Acacia Natural Gas Corp I, Inc. and the Partnership's acquisition of Victoria Express Pipeline and related truck terminal and storage assets from Devon (the "VEX Interests").

Non-GAAP Financial Measures

We include the following non-GAAP financial measures in the exhibits to this Current Report on Form 8-K: adjusted EBITDA, gross operating margin and distributable cash flow.

Adjusted EBITDA

We define adjusted EBITDA as net income from continuing operations plus interest expense, provision for income taxes, depreciation and amortization expense, impairment expense, stock-based compensation, gain on noncash derivatives, transaction costs, distribution of equity investment and non-controlling interest and income on equity investment. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

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

The GAAP measures most directly comparable to adjusted EBITDA are net income from continuing operations and net cash provided by operating activities. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income from continuing operations, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA may not be comparable to similarly titled measures of other companies because other entities may not calculate adjusted EBITDA in the same manner.

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

Distributable Cash Flow

We define distributable cash flow as net cash provided by operating activities plus adjusted EBITDA, net to EnLink Midstream Partners, LP less interest expense, litigation settlement adjustment, interest rate swap, cash taxes and other, maintenance capital expenditures and Predecessor adjusted EBITDA. Distributable cash flow is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner.

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

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

Reconciliation of net income from continuing operations to Adjusted EBITDA	**Years Ended December 31,**		
	2014 (1)	**2013**	**2012**
	(In millions)		
Net income from continuing operations	$ 309.3	$ 119.1	$ 82.1
Interest expense	47.4	—	—
Depreciation and amortization	284.3	187.0	145.4
Impairment	—	—	16.4
Income from equity investments	(18.9)	(14.8)	(2.0)
Gain on extinguishment of debt	(3.2)	—	—
Distribution from equity investments	23.7	12.0	2.3
Stock-based compensation	22.2	12.8	12.8
Income taxes	22.0	67.0	46.2
Payments under onerous performance obligation offset to other current and long-term liabilities	(14.7)	—	—
Other (2)	(18.5)	—	—
Adjusted EBITDA before non-controlling interest, other acquired interests and Predecessor interests	$ 653.6	$ 383.1	$ 303.2
Non-controlling interest share of adjusted EBITDA (3)	(0.2)	—	—
Transferred Interests, E2 and VEX Interests adjusted EBITDA	(193.0)	—	—
Predecessor adjusted EBITDA	(82.8)	(383.1)	(303.2)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 377.6	$ —	$ —

(1) Information has been recast to include results attributable to the Transferred Interests and VEX Interests.

(2) Includes financial derivatives marked-to-market, accretion expense associated with asset retirement obligations and transaction costs.

(3) Includes non-controlling interest share of E2 losses of $0.2 million.

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

	Years Ended December 31,		
	2014 (1)	2013	2012
	(in millions)		
Net cash provided by operating activities	$ 479.4	$ 330.3	$ 209.7
Interest expense, net (2)	48.6	—	—
Unit-based compensation (3)	2.8	12.8	12.8
Current income tax (benefit)	6.7	31.5	59.2
Distributions from equity investment in excess of earnings	10.9	1.1	1.9
Other (4)	3.5	(0.4)	(0.4)
Changes in operating assets and liabilities which provided cash:			
Accounts receivable, accrued revenues, inventories and other	98.1	(0.8)	2.5
Accounts payable, accrued purchases and other (5)	3.6	8.6	17.5
Adjusted EBITDA before non-controlling interest	$ 653.6	$ 383.1	$ 303.2
Non-controlling interest share of adjusted EBITDA	(0.2)	—	—
Transferred Interests, E2 and VEX Interests adjusted EBITDA	(193.0)	—	—
Predecessor adjusted EBITDA (6)	(82.8)	(383.1)	(303.2)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 377.6	$ —	$ —
Interest expense	(46.3)	—	—
Litigation settlement adjustment (7)	(4.7)	—	—
Interest rate swap (8)	(3.6)	—	—
Cash taxes and other	(0.1)	—	—
Maintenance capital expenditures	(21.5)	—	—
Distributable cash flow	$ 301.4	$ —	$ —

(1) Information has been recast to include results attributable to the Transferred Interests and VEX Interests.

(2) Net of amortization of debt issuance costs and discount and premium included in interest expense.

(3) Represents Predecessor stock-based compensation contributed through equity and reflected in net distributions to Predecessor in cash flows from financing activities in the Consolidated Statements of Cash Flows.

(4) Includes transaction costs.

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

(6) Represents Predecessor adjusted EBITDA.

(7) Represents portion of litigation settlement related to the reimbursement of capital expenditures.

(8) During the fourth quarter of 2014, we entered into interest rate swap arrangements to mitigate our exposure to interest rate movements prior to our note issuances. The gain on settlement of the interest rate swaps was considered excess proceeds for the note issuance, and therefore, excluded from distributable cash flow.

Gross Operating Margin

We define gross operating margin as revenues minus cost of purchased gas, NGLs, condensate and crude oil. We present gross operating margin by segment in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" in Exhibit 99.3 to this Current Report on Form 8-K. We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of gross operating margin to operating income:

	Years Ended December 31,		
	2014 (1)	2013	2012
		(In millions)	
Total gross operating margin	$ 1,013.3	$ 559.6	$ 479.7
Add (deduct):			
Operating expenses	(283.6)	(156.2)	(149.9)
General and administrative expenses	(94.5)	(45.1)	(41.7)
Depreciation, amortization and impairments	(284.3)	(187.0)	(161.8)
Gain on sale of property	0.1	—	—
Gain on litigation settlement	6.1	—	—
Operating income	$ 357.1	$ 171.3	$ 126.3

(1) Information has been recast to include results attributable to the VEX Interests.

Management's Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included in Exhibit 99.4 to this Current Report on Form 8-K. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the financial statements included in Exhibit 99.4 to this Current Report on Form 8-K.

The historical financial statements included in this Exhibit 99.4 to this Current Report on Form 8-K reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to EnLink Midstream Holdings, LP ("Midstream Holdings"), which is the historical predecessor of EnLink Midstream Partners, LP and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream Partners, LP after giving effect to the business combination discussed under "Devon Energy Transaction" below. The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon Energy Corporation ("Devon") prior to the business combination, including its 38.75% interest in Gulf Coast Fractionators ("GCF"). However, in connection with the business combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

You should read this discussion in conjunction with the historical financial statements and accompanying notes included in Exhibit 99.4 to this Current Report on Form 8-K. All references in this section to the "Partnership", as well as the terms "our," "we," "us" and "its" (1) for periods prior to March 7, 2014 refer to the Predecessor and (2) for periods on or after March 7, 2014 refer to EnLink Midstream Partners, LP, together with its consolidated subsidiaries including EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.) (the "Operating Partnership") and Midstream Holdings.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 8,900 miles of pipelines, thirteen natural gas processing plants, seven fractionators, 3.1 million barrels of NGL cavern storage, 11.0 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. We manage and report our activities primarily according to geography. We have five reportable segments: (1) Texas, which includes our activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes our activities in Cana-Woodford and Arkoma-Woodford Shale areas; (3) Louisiana, which includes our pipelines, processing plants and NGL assets located in Louisiana; (4) Ohio River Valley ("ORV"), which includes our crude oil activities in the Utica and Marcellus Shales, our equity interests in E2 Energy Services, LLC, E2 Appalachian Compression, LLC and E2 Ohio Compression, LLC (collectively, "E2") and crude oil activities associated with the Victoria Express Pipeline and related truck terminal and storage assets ("VEX") located in the Eagle Ford shale in south Texas; and (5) Corporate Segment, or Corporate, which includes our equity investments in Howard Energy Partners, or HEP, in the Eagle Ford Shale, our contractual right to the economic burdens and benefits associated with Devon's ownership interest in GCF in south Texas and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas, NGLs, crude oil and condensate for a margin or to gather, process, transport or market natural gas, NGLs, crude oil and condensate for a fee. In addition, we earn a volume based fee for brine disposal services and condensate stabilization. We define gross operating margin as operating revenue minus cost of purchased gas, NGLs, condensate and crude oil. Gross operating margin is a non-generally accepted accounting principle, or non-GAAP, financial measure and is explained in greater detail under "Non-GAAP Financial Measures" under Selected Financial Data in Exhibit 99.2 to this Current Report on Form 8-K.

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities, the volumes of crude oil and condensate handled at our crude terminals, the volumes of crude oil and condensate gathered, transported, purchased and sold, the volume of brine disposed and the volume of condensate stabilized. We generate revenues from eight primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing the recovered NGLs;

- providing compression services;
- purchasing and reselling crude oil and condensate;
- providing crude oil and condensate transportation and terminal services;
- providing condensate stabilization services; and
- providing brine disposal services.

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the same market index. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, on occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our margin. Changes in the basis spread can increase or decrease our margins.

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 potentially result in losses. For example, we are a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices on its 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 fair value of this performance obligation was recorded as a result of the March 7, 2014 business combination and was based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of December 31, 2014, the balance sheet reflects a liability of $80.7 million related to this performance obligation. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

The majority of our NGL fractionation business, which includes transportation, fractionation, and storage, is under fee-based arrangements. We are typically paid a fixed fee based on the volume of NGLs transported, fractionated or stored. On our Cajun-Sibon pipeline, we buy the mixed NGL stream from our suppliers for an indexed-based price for the component NGLs with a deduction for our fractionation fee. After the NGLs are fractionated, we sell the fractionated NGL products based on the same index-based prices. The operating results of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With our fractionation business, we also have the opportunity for product upgrades for each of the discrete NGL products. The margins we realize on the product upgrade from this fractionation business are higher during periods with high liquids prices.

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

We also realize gross operating margins from our processing services primarily through three different contract arrangements: processing margins ("margin"), percentage of liquids ("POL") or fixed-fee based. Under margin contract arrangements our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Under fixed-fee based contracts our gross operating margins are driven by throughput volume. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014 (the “2014 Form 10-K”) filed with the Securities and Exchange Commission (“SEC”) on February 20, 2015.

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

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

Devon Energy Transaction

On March 7, 2014, the Partnership consummated the transactions contemplated by the Contribution Agreement, dated as of October 21, 2013 (the “Contribution Agreement”), among the Partnership, the Operating Partnership, Devon, Devon Gas Corporation, Devon Gas Services, L.P. (“Gas Services”) and Southwestern Gas Pipeline, Inc. (“Southwestern Gas” and, together with Gas Services, the “Contributors”) pursuant to which the Contributors contributed (the “Contribution”) to the Operating Partnership a 50% limited partner interest in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings (“Midstream Holdings GP” 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”). On February 17, 2015, the Partnership acquired a 25% limited partner interest in Midstream Holdings (the “February Transferred Interests”) from Acacia, a wholly-owned subsidiary of ENLC, in a drop down transaction (the “February EMH Drop Down”). As consideration for the February Transferred Interests, the Partnership issued 31.6 million Class D Common Units in the Partnership to Acacia. On May 27, 2015, the Partnership acquired the remaining 25% interest in Midstream Holdings (the "May Transferred Interests" and, together with the February Transferred Interests, the "Transferred Interests") from Acacia in a drop down transaction (the "May EMH Drop Down" and, together with the February EMH Drop Down, the "EMH Drop Downs"). As consideration for the May Transferred Interests, the Partnership issued 36.6 million Class E Common Units in the Partnership to Acacia. After giving effect to the EMH Drop-Downs, the Partnership owns 100% of Midstream Holdings. See “Recent Growth Developments.”

The Partnership units held by Devon represent approximately 49% of the outstanding limited partner interests in the Partnership, with approximately 43% 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 ENLC, as of December 31, 2014, which does not reflect the partnership interest acquired in the EMH Drop Downs. The Class B Units were substantially similar in all respects to the Partnership’s common units representing limited partnership interests in the Partnership (“Common Units”), except that they were only entitled to a pro rata distribution for the fiscal quarter ended March 31, 2014. The Class B Units automatically converted into Common Units on a one-for-one basis on May 6, 2014.

Also on March 7, 2014, EnLink Midstream, Inc. (“EMI”) and Devon consummated the transactions contemplated by the Merger Agreement, dated as of October 21, 2013 (the “Merger Agreement”), among EMI, Devon, ENLC, Acacia, formerly a wholly-owned subsidiary of Devon, and certain other wholly-owned subsidiaries of Devon pursuant to which EMI and Acacia each became wholly-owned subsidiaries of ENLC (collectively, the “Mergers” and together with the Contribution, the “business combination”). Upon completion of the merger with Acacia, ENLC indirectly owned the remaining 50% limited partner interest in Midstream Holdings (which was transferred in the EMH Drop Downs).

Recent Growth Developments

Organic Growth

Ohio River Valley Condensate Pipeline and Condensate Stabilization Facilities. In August 2014, we announced plans to construct a new 45-mile, eight-inch condensate pipeline and six natural gas compression and condensate stabilization facilities that will service major producer customers in the Utica Shale, including Eclipse Resources. As a component of the project, the Partnership has entered into a long-term, fee-based agreement under which Eclipse Resources will receive compression and stabilization services and has agreed to sell stabilized condensate to us.

The new-build stabilized condensate pipeline will connect to our existing 200-mile pipeline in the ORV, providing producer customers in the region access to premium market outlets through our barge facility on the Ohio River and rail terminal in Ohio. The pipeline, which is expected to be complete in the second half of 2015, is expected to have an initial capacity of approximately 50,000 Bbls/d.

We also expect to build and operate six natural gas compression and condensate stabilization facilities in Noble, Belmont, and Guernsey counties in Ohio. Upon completion, the facilities will have a combined capacity of approximately 560 MMcf/d of natural gas compression and approximately 41,500 Bbls/d of condensate stabilization. The first two compression and condensate stabilization facilities began operations during the fourth quarter of 2014 and the remaining four facilities are expected to be operational by the end of 2015.

In support of the project, we plan to leverage and expand our existing midstream assets in the region, including increasing condensate storage capacity and handling capabilities at our barge terminal on the Ohio River. We will add approximately 130,000 barrels of above ground storage, bringing our total storage capacity at the barge facility to over 360,000 barrels.

Marathon Petroleum Joint Venture. We have entered into a series of agreements with a subsidiary of Marathon Petroleum Corporation to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will build a new 30-mile NGL pipeline connecting our existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. The bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, we will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Cajun-Sibon Phases I and II. In Louisiana, we have transformed our business that historically has been focused on processing offshore natural gas to a business that is now 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 now 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.

The pipeline expansion and the Eunice fractionation expansion under Phase I were completed and commenced operation in November 2013. Phase II of the Cajun-Sibon expansion was completed and commenced operation in September 2014, which increased the Cajun-Sibon pipeline capacity by an additional 50,000 Bbls/d to approximately 130,000 Bbls/d and added a new 100,000 Bbl/d fractionator at our Plaquemine gas processing complex. The throughput of the pipeline averaged 109,900 Bbls/d during the fourth quarter of 2014. Our fractionators in south Louisiana averaged approximately 98,300 Bbls/d during the fourth quarter of 2014.

We believe the Cajun-Sibon project represents a tremendous growth step by leveraging our Louisiana assets and also by creating 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 September 2014, we completed construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin called Bearkat. The natural gas processing complex includes treating, processing and gas takeaway solutions for regional producers. The project, which is fully owned by us, is supported by a 10-year, fee-based contract.

Bearkat is strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant has an initial capacity of 60 MMcf/d, increasing our total operational processing capacity in the Permian Basin to approximately 115 MMcf/d. We also completed construction of a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan counties.

During 2014, we constructed a new 35-mile, 12-inch diameter high-pressure pipeline to provide gathering capacity for the Bearkat natural gas processing complex. The pipeline has an initial capacity of approximately 100 MMcf/d and provides gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The pipeline commenced operation in the fourth quarter of 2014.

Growing with Devon

West Texas Expansion. We are expanding our natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing plant and expanding our rich gas gathering system. The new 120 MMcf/d gas processing plant will be strategically located on the north end of our existing midstream assets and will offer additional gas processing capabilities to producer customers in the region, including Devon. Due to the impact from the current commodity environment and a shift in producers' drilling expectations, we are delaying construction on the processing plant until late 2015. Upon completion, our total operated processing capacity in the region will be approximately 240 MMcf/d.

As a part of the expansion, we have signed a long-term, fee-based agreement with Devon to provide gathering and processing services for over 18,000 acres under development in Martin County. We constructed multiple low pressure gathering pipelines and a new 23-mile, 12-inch high pressure gathering pipeline that will tie into the previously announced Bearkat natural gas gathering system. The new pipelines commenced operation in January 2015.

Drop Downs

Midstream Holdings Drop Down. On February 17, 2015, the Partnership acquired the February Transferred Interests from Acacia, a wholly-owned subsidiary of ENLC, in the February EMH Drop Down. As consideration for the February Transferred Interests, the Partnership issued 31.6 million Class D Common Units in the Partnership to Acacia. The Partnership's Class D Common Units converted into the Partnership's Common Units on a one-for-one basis May 4, 2015.

On May 27, 2015, the Partnership acquired the May Transferred Interests from Acacia in the May EMH Drop Down. As consideration for the May Transferred Interests, the Partnership issued 36.6 million Class E Common Units in the Partnership to Acacia. The Partnership's Class E Common Units are substantially similar in all respects to the Partnership's Common Units, except that they will only be entitled to a pro rata distribution for the fiscal quarter ended June 30, 2015. The Partnership's Class E Common Units will automatically convert into the Partnership's 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 June 30, 2015. After giving effect to the EMH Drop Downs, the Partnership owns 100% of Midstream Holdings.

VEX Interests. On April 1, 2015, the Partnership acquired VEX from Devon (the "VEX Interests"), which are located in the Eagle Ford shale in south Texas. The aggregate consideration paid by the Partnership consisted of $171.0 million in cash, 338,159 common units representing limited partner interests in the Partnership with an aggregate value of approximately $9 million and the Partnership's assumption of up to $40 million in certain construction costs related to VEX, subject to certain adjustments set forth in the contribution agreement. The VEX pipeline is a 56-mile multi-grade crude oil pipeline with a current capacity of approximately 50,000 Bbls/d and, following completion of currently-underway expansion projects, will have capacity of approximately 90,000 Bbls/d. Other VEX assets at the destination of the pipeline include an eight-bay truck unloading terminal, 200,000 barrels of above-ground storage, of which 50,000 barrels are under construction, and rights to barge loading docks.

E2 Drop Down. On October 22, 2014, the Partnership acquired from EMI, a wholly-owned subsidiary of ENLC, 100% of the Class A Units and 50% of the Class B Units (collectively, the "E2 Appalachian Units") in E2 Appalachian Compression, LLC ("E2 Appalachian"), and 93.7% of the Class A Units (the "Energy Services Units" and, together with the E2 Appalachian Units, the "Purchased Units") in E2 Energy Services, LLC ("Energy Services"). The total consideration paid by the Partnership to EMI for the Purchased Units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in the Partnership for the E2 Appalachian Units. The remaining 50% of the Class B Units in E2 Appalachian are owned by members of the E2 Appalachian management team and are designed to provide such management team members with equity incentives.

E2's assets include five condensate stabilization and natural gas compression stations with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression located in the ORV. Currently, three of the five stations are in service and commercial start-up of the two remaining stations is expected in the first half of 2015. The assets are supported by a long-term, fee-based contract with Antero Resources.

Acquisitions

Coronado Midstream. On February 1, 2015, the Partnership entered into an agreement with Reliance Midstream, LLC, a Texas limited liability company ("Reliance"), Windsor Midstream LLC, a Delaware limited liability company ("Windsor"), Wallace Family Partnership, LP, a Texas limited partnership ("Wallace"), and Ted Collins, Jr., an individual residing in Midland, Texas ("Collins" and, collectively with Reliance, Windsor and Wallace, the "Sellers," and each, a "Seller"), and Reliance in its capacity as representative of the Sellers, to acquire all of the equity interests in Coronado Midstream Holdings LLC, the parent company of Coronado Midstream LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin for approximately $600.0 million in cash and equity, subject to certain adjustments. Coronado operates three cryogenic gas processing plants and a gas gathering system in the North Midland Basin including approximately 270 miles of gathering pipelines, 175 MMcf/d of processing capacity and 35,000 horsepower of compression. The Coronado system is underpinned by long-term contracts, which include the dedication of production from over 190,000 acres.

LPC Crude Oil Marketing ("LPC"). On January 31, 2015, the Partnership, through one of its wholly owned subsidiaries, acquired LPC, which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $100.0 million. LPC is an integrated crude oil logistics service provider with operation throughout the Permian Basin. LPC's integrated logistics services are supported by 41 tractor trailers, 13 pipeline injection stations and 67 miles of crude oil gathering pipeline.

Natural Gas Pipeline Assets. On November 1, 2014, we acquired Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, for $234.0 million, subject to certain adjustments. These natural gas pipeline assets include the following:

- *Bridgeline System:* approximately 990 miles of natural gas pipelines in southern Louisiana with a total system capacity of approximately 900 MMcf/d;
- *Sabine Pipeline:* approximately 130 miles of natural gas pipelines in Texas and southern Louisiana with a total capacity of approximately 300 MMcf/d;

- *Chandeleur System*: approximately 215 miles of offshore Mississippi and Alabama pipelines with a total capacity of approximately 300 MMcf/d;
- *Storage Assets:* three caverns located in southern Louisiana with a combined working capacity of approximately 11 Bcf of natural gas, including two near Sorrento, LA with a capacity of approximately 4.0 Bcf and one inactive cavern near Napoleonville, LA with approximately 7.0 Bcf of capacity; and
- *Henry Hub:* ownership and management of the title tracking services offered at the Henry Hub, the delivery location for the New York Mercantile Exchange (the "NYMEX") natural gas futures contracts. Henry Hub is connected to 13 major interstate and intrastate natural gas pipeline and storage systems.

Issuance of Common Units

In November 2014, the Partnership issued 12,075,000 common units representing limited partner interests in the Partnership at an offering price of $28.37 per unit for net proceeds of $332.3 million. The net proceeds from the common units offering were used for capital expenditures and general partnership purposes.

In November 2014, the Partnership entered into an Equity Distribution Agreement (the "BMO EDA") with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the "Sales Agents") to sell up to $350.0 million in aggregate gross sales of the Partnership's common units representing limited partner interests from time to time through an "at the market" equity offering program. The Partnership may also sell Common Units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. The Partnership has no obligation to sell any of the Common Units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. Through December 2014, the Partnership sold an aggregate of 0.3 million common units under the BMO EDA, generating proceeds of approximately $7.8 million (net of approximately $0.1 million of commissions). The Partnership used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

In October 2014, the Partnership issued 1,016,322 common units to ENLC representing limited partner interests in the Partnership as partial consideration for E2 Appalachian Units.

In May 2014, the Partnership entered into an Equity Distribution Agreement (the "EDA") with BMO Capital Markets Corp. ("BMOCM"). Pursuant to the terms of the EDA, the Partnership may from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Through December 31, 2014, the Partnership sold an aggregate of 2.4 million common units under the EDA, generating proceeds of approximately $71.9 million (net of approximately $0.7 million of commissions to BMOCM). The Partnership used the net proceeds for general partnership purposes.

Results of Operations

The table below sets forth certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin which we define as operating revenue less cost of purchased gas, NGLs, condensate and crude oil as reflected in the table below.

Items Affecting Comparability of Our Financial Results

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

- In connection with the business combination, Midstream Holdings entered into new agreements with Devon that were effective on March 1, 2014 pursuant to which Midstream Holdings provides services to Devon under fixed-fee arrangements in which Midstream Holdings does not take title to the natural gas gathered or processed or the NGLs it fractionates. Prior to the effectiveness of these agreements, the Predecessor provided services to Devon under a percent-of-proceeds arrangement in which it took title to the natural gas it gathered and processed and the NGLs it fractionated.

- Prior to March 7, 2014, our financial results only included the assets, liabilities and operations of our Predecessor. Beginning on March 7, 2014, our financial results also consolidate the assets, liabilities and operations of the legacy business of the Partnership prior to giving effect to the business combination.

- Our financial statements for the year ended December 31, 2014 report financial results according to operating segments based principally upon geographic regions served. The Predecessor had no operations for certain of those reporting segments.

- All historical affiliated transactions prior to March 7, 2014 related to our continuing operations were net settled within our combined financial statements because these transactions related to Devon and were funded by Devon's working capital. Beginning on March 7, 2014, all our transactions are funded by our working capital. This impacts the comparability of our cash flow statements, working capital analysis and liquidity discussion.

- The Predecessor’s historical 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 a contractual right to the economic burdens and benefits of its 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the consummation of the business combination. Assets that were not contributed to Midstream Holdings are included in discontinued operations.
- The Predecessor’s historical combined financial statements include U.S. federal and state income tax expense. Due to Midstream Holdings’ status as a partnership, Midstream Holdings will not be subject to U.S. federal income tax or certain state income taxes in the future.

	For years ended December 31,		
	2014 (1)	2013	2012
	(in millions, except volumes)		
Texas Segment			
Revenues	$ 1,067.2	$ 1,549.1	$ 1,357.2
Purchased gas and NGLs	(490.9)	(1,130.4)	(983.3)
Total gross operating margin	$ 576.3	$ 418.7	$ 373.9
Louisiana Segment			
Revenues	$ 1,925.5	$ —	$ —
Purchased gas, NGLs and crude oil	(1,754.2)	—	—
Total gross operating margin	$ 171.3	$ —	$ —
Oklahoma Segment			
Revenues	$ 318.8	$ 746.8	$ 550.6
Purchased gas and NGLs	(142.5)	(605.9)	(444.8)
Total gross operating margin	$ 176.3	$ 140.9	$ 105.8
Ohio River Valley (2)			
Revenues	$ 268.7	$ —	$ —
Purchased crude oil and condensate	(201.4)	—	—
Total gross operating margin	$ 67.3	$ —	$ —
Corporate			
Revenues	$ (72.4)	$ —	$ —
Purchased gas, NGLs and crude oil	94.5	—	—
Total gross operating margin	$ 22.1	$ —	$ —
Total			
Revenues	$ 3,507.8	$ 2,295.9	$ 1,907.8
Purchased gas, NGLs, crude oil and condensate	(2,494.5)	(1,736.3)	(1,428.1)
Total gross operating margin	$ 1,013.3	$ 559.6	$ 479.7
Midstream Volumes:			
Texas (3)			
Gathering and Transportation (MMBtu/d)	2,958,000	2,102,000	2,127,000
Processing (MMBtu/d)	1,146,000	811,000	753,000
Louisiana (4)			
Gathering and Transportation (MMBtu/d)	615,200	—	—
Processing (MMBtu/d)	547,000	—	—
NGL Fractionation (Gals/d) (6)	3,804,300	—	—
Oklahoma (5)			
Gathering and Transportation (MMBtu/d)	471,000	390,000	351,000
Processing (MMBtu/d)	442,000	400,000	340,000
ORV (2)(4)			
Crude Oil Handling (Bbls/d)	26,300	—	—
Brine Disposal (Bbls/d)	4,700	—	—

(1) Financial information has been recast to include the financial position and results attributable to the Transferred Interests and VEX Interests.

(2) The crude oil operating activities attributable to the VEX Interests are included with ORV's crude oil activities for segment reporting.

(3) Volumes include volumes per day based on 365 day period for the years ended December 31, 2014, 2013 and 2012 for Midstream Holdings operations. Volumes include volumes per day based on the 300 day period from March 7 to December 31, 2014 for the year ended December 31, 2014 for the Partnership's legacy operations in Texas.

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

(5) Volumes include volumes per day based 365 day period for the years ended December 31, 2014, 2013 and 2012 respectively, for Midstream Holdings operations. The Partnership did not have any legacy operations in Oklahoma.

(6) NGL fractionation volumes for the quarterly periods ended March 31, 2014, June 30, 2104 and September 30, 2014 reflected in our quarterly reports on Form 10-Q for the respective periods were overstated due to a clerical error in compiling such information. The corrected NGL fractionation volumes based on gallons per day for the quarters ended March 31, 2014, June 30, 2014 and September 30, 2014 were 3,336,800, 3,360,400 and 2,727,400, respectively, as compared to the previously reported volumes of 3,291,900, 4,377,300 and 4,073,500, respectively.

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

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

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

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

Depreciation and Amortization. Depreciation and amortization expenses were $284.3 million for the year ended December 31, 2014 compared to $187.0 million for the year ended December 31, 2013, an increase of $97.3 million, or 52.0%. The increase in depreciation and amortization expenses result from an increase in depreciation expense of $137.9 million related to the legacy Partnership assets acquired in March 2014 together with additional depreciation for net asset additions during 2014 and $4.0 million attributable to the VEX pipeline. These increases were partially offset by a decrease of $44.6 million in depreciation and amortization expenses related to Midstream Holdings primarily due to the change in depreciation methodology from the units-of-production method to the straight-line method which accounted for $29.4 million of such decrease. The remaining $5.6 million decrease was related to a change in the annual units-of-production rate partially offset by a $1.7 million increase related to assets placed in service during 2013.

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

Interest Expense. Interest expense was $47.4 million for the year ended December 31, 2014. There was no interest expense for the year ended December 31, 2013 as Midstream Holdings did not have any debt. Net interest expense consists of the following (in millions):

	Year Ended December 31,
	2014
Senior notes	$ 55.6
Bank credit facility	5.8
Capitalized interest	(11.5)
Amortization of debt issue costs and net discount (premium)	(1.2)
Cash settlements on interest rate swap	(3.6)
Other	2.3
Total	$ 47.4

Income from Equity Investments. Income from equity investments was $18.9 million for the year ended December 31, 2014 compared to $14.8 million for the year ended December 31, 2013, an increase of $4.1 million. Of this increase in income from equity investments, $1.8 million is attributable to legacy Partnership equity investments. The remaining increase relates to our investment in GCF due to an improvement in turnaround downtime experience as compared to the 2013 period.

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

Net Income from Discontinued Operations. Net income from discontinued operations was $1.0 million for the year ended December 31, 2014 as compared to a net loss of $3.6 million for the year ended December 31, 2013, an increase of $4.6 million. The increase is due to Midstream Holdings' discontinued operations for the year ended December 31, 2013 which included assets that were sold during 2013, while year ended December 31, 2014 includes Predecessor assets that were not contributed to Midstream Holdings as part of the business combination.

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

Gross Operating Margin. Gross operating margin was $559.6 million for the year ended December 31, 2013 compared to $479.7 million for the year ended December 31, 2012, an increase of $79.9 million, or 16.7%. Higher gathering, processing and transportation volumes were responsible for an increase in gross 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 gross 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 gross 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 gross operating margin. These increases were partially offset by lower margins of $28.2 million primarily due to NGL price declines.

Operating Expenses. Operating expenses were $156.2 million for the year ended December 31, 2013 compared to $149.9 million for the year ended December 31, 2012, an increase of $6.3 million, or 4.2%. The increase primarily relates to an increase of $4.8 million related to higher ad valorem tax assessments on Midstream Holdings' Cana assets offset by decrease in other expenses.

General and Administrative Expenses. General and administrative expenses were $45.1 million for the year ended December 31, 2013 compared to $41.7 million for the year ended December 31, 2012, an increase of $3.4 million, or 8.2%. The increase is primarily due to higher employee compensation and benefits.

Depreciation and Amortization. Depreciation and amortization expenses were $187.0 million for the year ended December 31, 2013 compared to $145.4 million for the year ended December 31, 2012, an increase of $41.6 million, or 28.6%. 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.

Income from Equity Investments. Income from equity investments was $14.8 million for the year ended December 31, 2013 compared to $2.0 million for the year ended December 31, 2012. The increase relates to our investment in GCF due to an increase in volumes.

Income Tax Expense. Income tax expense was $67.0 million for the year ended December 31, 2013 as compared to income tax expense of $46.2 million for the year ended December 31, 2012, an increase of $20.8 million. This increase primarily relates to an increase in taxable income related to the Predecessor. 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.

Supplemental Information

As a supplement to the financial information included herein for the year ended December 31, 2014, the Partnership is furnishing the following table, which segregates the results of operations of Midstream Holdings from the Partnership's other operations. The tables below reflect the following for the year ended December 31, 2014:

- the Predecessor's results of operations for the period January 1, 2014 through March 6, 2014;
- the Partnership's results of operations excluding the operations of Midstream Holdings for the period March 7, 2014 through December 31, 2014;
- the results of operations of 100% of Midstream Holdings on a stand-alone basis for the period March 7, 2014 through December 31, 2014; and
- the Partnership's results of operations on a consolidated basis.

	Year Ended December 31, 2014 (1)			
	Predecessor	Partnership Excluding Midstream Holdings	Midstream Holdings	Partnership Consolidated
	(in millions)			
Revenues:				
Revenues	$ 47.3	$ 2,365.4	$ —	$ 2,412.7
Revenues - affiliates	436.4	115.3	521.3	1,073.0
Gain on derivatives	—	22.1	—	22.1
Total revenues	483.7	2,502.8	521.3	3,507.8
Operating costs and expenses:				
Purchased gas, NGLs, condensate and crude oil	368.5	2,116.0	10.0	2,494.5
Operating expenses	23.7	145.7	114.2	283.6
General and administrative	10.9	52.9	30.7	94.5
Depreciation and amortization	28.9	138.0	117.4	284.3
Gain on sale of property	—	(0.1)	—	(0.1)
Gain on litigation settlement	—	(6.1)	—	(6.1)
Total operating costs and expenses	432.0	2,446.4	272.3	3,150.7
Operating income	51.7	56.4	249.0	357.1
Other income (expense):				
Interest expense, net of interest income	—	(47.4)	—	(47.4)
Income from equity investments	2.8	1.8	14.3	18.9
Gain on extinguishment of debt	—	3.2	—	3.2
Other expense	(0.5)	0.2	(0.2)	(0.5)
Total other income (expense)	2.3	(42.2)	14.1	(25.8)
Income from continuing operations before non-controlling interest and income taxes	54.0	14.2	263.1	331.3
Income tax provision	(19.5)	(0.5)	(2.0)	(22.0)
Net income from continuing operations	34.5	13.7	261.1	309.3
Discontinued operations:				
Income from discontinued operations, net of tax	1.0	—	—	1.0
Discontinued operations, net of tax	1.0	—	—	1.0
Net income	35.5	13.7	261.1	310.3
Net income attributable to the non-controlling interest	—	(0.2)	—	(0.2)
Net income attributable to EnLink Midstream Partners, LP	$ 35.5	$ 13.9	$ 261.1	$ 310.5

(1) Financial information has been recast to include the financial position and results attributable to the Transferred Interests and VEX Interests.

Critical Accounting Policies

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

Our critical accounting policies are discussed below. See *Note 2-Significant Accounting Policies* in Exhibit 99.4 to this Current Report on Form 8-K for further details on our accounting policies.

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

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

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

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

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, we evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, NGLs and crude oil, volume of gas, NGLs and crude oil available to the asset, markets available to the asset, operating expenses, and future natural gas, NGL product and crude oil prices. The amount of availability of gas, NGLs and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas and crude oil prices. Projections of gas, NGL and crude oil volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

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

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

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

At October 31, 2014, the date of our last impairment test, the fair values of our Texas, Louisiana, Oklahoma and ORV reporting units exceeded their related carrying values. The fair value of our Texas, Oklahoma and ORV reporting units substantially exceeded carrying value. However, the fair value of our Louisiana reporting unit is not substantially in excess of its carrying value. As of October 31, 2014, the fair value of our Louisiana reporting unit exceeded its carrying value by approximately 14 percent. As of December 31, 2014, we had $786.8 million of goodwill allocated to the Louisiana reporting unit.

Significant decreases to our unit price, decreases in commodity prices or negative deviations from projected Louisiana reporting unit earnings could result in a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Due to the inter-relationship of the various estimates involved in assessing goodwill for impairment, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates.

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

Historically, Midstream Holdings depreciated certain property, plant, and equipment using the units-of-production method. As a result of the business combination, Midstream Holdings is operated as an independent midstream company and thus no longer has access to Devon’s proprietary reserve and production data historically used to compute depreciation under the units-of-production method. Additionally, the existing contracts with Devon were revised to a fee-based arrangement with minimum volume commitments. Effective March 7, 2014, the Partnership changed its method of computing depreciation for these assets to the straight-line method, consistent with the depreciation method applied to the Partnership’s legacy assets. In accordance with FASB ASC 250, the Partnership determined that the change in depreciation method is a change in accounting estimate, and accordingly, the straight-line method will be applied on a prospective basis. This change is considered preferable because the straight-line method more accurately reflects the pattern of usage and the expected benefits of such assets.

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

Commodity Price Risk

We are subject to significant risks due to fluctuation in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. Processing margin and POL contracts are two types of contracts under which we process gas and are exposed to commodity price risk. For the year ended December 31, 2014, approximately 1.7% of our processed gas arrangements, based on gross operating margin, were processed under POL contracts. A portion of the volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. Under these contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the costs of the natural gas volumes lost (“shrink”). Accordingly, our revenues under these contracts are directly impacted by the market price of NGLs.

We also realize processing gross operating margin under margin contracts and spot purchases. For the year endedDecember 31, 2014, approximately 2.1% of our processed gas arrangements, based on gross operating margin, was processed under margin contracts and spot purchases. We have a number of margin contracts on our Plaquemine and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas shrink and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR.

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

In the past, the prices of oil, natural gas and NGLs have been extremely volatile, 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 2014 ranged from a high of $107.26 per Bbl in June 2014 to a low of $53.27 per Bbl in December 2014. Weighted average NGL prices in 2014 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $1.22 per gallon in February 2014 to a low of $0.45 per gallon in December 2014. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2014 ranged from a high of $7.94 per MMBtu in March 2014 to a low of $2.75 per MMBtu in December 2014.

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, NGLs, crude oil and condensate we gather and process. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. For a discussion of our risk management activities, please read “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $479.4 million, $330.3 million and $209.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. Operating cash flows and changes in working capital for 2014, 2013 and 2012 were as follows (in millions):

	Years Ended December 31,		
	2014	**2013**	**2012**
Operating cash flows before working capital	$ 590.0	$ 338.2	$ 229.8
Changes in working capital	(110.6)	(7.9)	(20.1)
Total	$ 479.4	$ 330.3	$ 209.7

The primary reason for the increase in cash flows before working capital of $251.8 million from 2013 to 2014 relates to an increase in gross operating margin from the acquired legacy Partnership assets and Midstream Holdings assets. The decrease in working capital for 2014 related to fluctuations in trade receivable and payable balances is due to timing of collection and payments and changes in inventory balances due to normal operating fluctuations. Further, prior to March 7, 2014, all cash receipts for the Predecessor were deposited into Devon’s bank accounts, and all cash disbursements were made from these accounts. Cash transactions handled by Devon were reflected in intercompany advances between Devon and the Predecessor, all of which were settled through an adjustment to equity and reflected in cash flows from financing activities. Subsequent to March 7, 2014, Midstream Holdings handles all of its cash transactions and the changes in working capital are reflected in our cash flows from operating activities.

The increase in cash flows from 2013 to 2012 are primarily driven by the fluctuations in volume and price described previously in results of operations.

Cash Flows from Investing Activities. Net cash used in investing activities was $1,211.8 million, $243.2 million and $352.4 million for the years ended December 31, 2014, 2013 and 2012, respectively. Our primary use of cash related to investing activities for the years ended December 31, 2014, 2013 and 2012 was acquisition costs and capital expenditures, net of accrued amounts, and an investment in equity investments as follows (in millions):

	Years Ended December 31,		
	2014	2013	2012
Growth capital expenditures	$ 758.9	$ 180.8	$ 249.5
Maintenance capital expenditures	37.1	63.5	87.7
Acquisition of business and asset purchases (1)	421.1	—	—
Proceeds from sale of property	(0.1)	—	—
Investment in equity investments	5.7	—	17.1
Distribution from equity investment company in excess of earnings	(10.9)	(1.1)	(1.9)
Total	$ 1,211.8	$ 243.2	$ 352.4

(1) The VEX pipeline assets, which were acquired by Devon in February 2014 for $74.9 million, are reflected in acquisition of business and assets purchases.

Cash Flows from Financing Activities. Net cash provided by financing activities was $636.3 million and $86.2 million for the years ended December 31, 2014 and 2012, respectively, and net cash used in financing activities was $151.2 million for the year ended December 31, 2013. Our primary financing activities subsequent to March 7, 2014 consist of the following (in millions):

	Year Ended December 31,
	2014
Net repayments on bank credit facility	$ (140.0)
Senior unsecured notes borrowings	1,600.7
Redemption of 2018 notes	(760.3)
Partial redemption of 2022 notes	(36.4)
Net repayments on E2 credit facility	(13.8)
Net repayments under capital lease obligations	(3.0)
Debt refinancing costs	(18.5)
Proceeds from issuance of Partnership units	412.0

Distributions to unitholders including our general partner, and distributions to ENLC relating to its ownership interest in Midstream Holdings represent primary uses of cash in financing activities. Also, Midstream Holdings made distributions of $159.5 million to ENLC for the year ended December 31, 2014 relating to ENLC's 50% ownership interest in Midstream Holdings during such period. Total unitholder cash distributions made during the years ended December 31, 2014 were as follows (in millions):

	Year ended December 31,
	2014 (1)
Common units	$ 222.7
General partner interest (including incentive distribution rights)	17.1
Total	$ 239.8

(1) Excludes distribution declared for the fourth quarter of 2014, which was paid on February 12, 2015.

Prior to the business combination, Midstream Holdings’ continuing operations had no separate cash accounts. The owner contributions and distributions represent the net amount of all transactions that were settled with adjustments to equity. Midstream Holdings had distributions of $21.3 million to Devon for the year ended December 31, 2014 (relating to the period from January 1, 2014 to March 6, 2014), contributions from Devon of $105.7 million related to VEX pipeline for the year ended December 31, 2014, distributions to Devon of $151.2 million for the year ended December 31, 2013 and contributions from Devon of $87.8 million for the year ended December 31, 2012.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. We borrow money under our credit facility to fund checks as they are presented. As of December 31, 2014, we had approximately $749.1 million of available borrowing capacity under this facility, although our actual borrowing capacity is limited by our financial covenant. Changes in drafts payable for 2014 were as follows (in millions):

	Years Ended December 31,		
	2014	2013	2012
Increase (decrease) in drafts payable	$ 10.2	$ —	$ (1.6)

Capital Requirements. Our 2015 capital budget includes around $500.0 million of identified growth projects, including capitalized interest. Our primary capital projects for 2015 include the construction of our ORV condensate pipeline, Bearkat plant facilities and West Texas expansion project. During 2014, we invested in several capital projects which primarily included the expansion of the Cajun-Sibon NGL Pipeline and the construction of the Bearkat facilities. See “Recent Growth Developments” for further details.

We expect to fund our 2015 maintenance capital expenditures of around $50.0 million from operating cash flows. We expect to fund the growth capital expenditures from the proceeds of borrowings under our bank credit facility discussed below and proceeds from other debt and equity sources. In 2015, it is possible that not all of the planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2014, 2013 and 2012.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2014 is as follows (in millions):

	Payments Due by Period						
	Total	2015	2016	2017	2018	2019	Thereafter
Long-term debt obligations	$ 1,762.5	$ —	$ —	$ —	$ —	$ 400.0	$ 1,362.5
Bank credit facility	237.0	—	—	—	—	237.0	—
Other Debt	0.4	0.2	0.1	0.1	—	—	—
Interest payable on fixed long-term debt obligations	1,403.8	79.6	81.3	81.3	81.3	75.9	1,004.4
Capital lease obligations	23.0	4.8	4.8	6.8	2.9	1.6	2.1
Operating lease obligations	119.1	11.6	9.2	6.6	11.5	9.0	71.2
Purchase obligations	133.9	133.9	—	—	—	—	—
Delivery contract obligation	80.7	17.9	17.9	17.9	17.9	9.1	—
Inactive easement commitment*	8.0	1.0	1.0	1.0	1.0	1.0	3.0
Uncertain tax position obligations	2.0	2.0	—	—	—	—	—
Total contractual obligations (1)	$ 3,770.4	$ 251.0	$ 114.3	$ 113.7	$ 114.6	$ 733.6	$ 2,443.2

* Amounts related to inactive easements paid as utilized with remaining balance of easements not utilized due at end of 10 years.

(1) Financial information has been recast to include the financial position and results attributable to the VEX Interests.

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

The interest payable under our credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates, which will vary from time to time. However, given the same borrowing amount and rates in effect at December 31, 2014, our cash obligation for interest expense on our credit facility would be approximately $4.5 million per year.

Indebtedness

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

		2014
Bank credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2014 was 1.9%	$	237.0
Senior unsecured notes (due 2019), net of discount of $0.5 million, which bear interest at the rate of 2.70%		399.5
Senior unsecured notes (due 2022), including a premium of $21.9 million, which bear interest at the rate of 7.125%		184.4
Senior unsecured notes (due 2024), including a premium of $3.2 million, which bear interest at the rate of 4.40%		553.2
Senior unsecured notes (due 2044), net of discount of $0.3 million, which bear interest at the rate of 5.60%		349.7
Senior unsecured notes (due 2045), net of discount of $1.7 million, which bear interest at the rate of 5.05%		298.3
Other debt		0.4
Debt classified as long-term	$	2,022.5

Credit Facility. On February 20, 2014, the Partnership entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the "Partnership credit facility"). On February 5, 2015, the commitments under the Partnership credit facility were increased to $1.5 billion and the maturity date was extended by a year. The Partnership credit facility will mature on the sixth anniversary of the initial funding date, which was March 7, 2014, unless the Partnership requests, and the requisite lenders agree, to extend it pursuant to its terms. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA may increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

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

As of December 31, 2014, there were $13.9 million in outstanding letters of credit and $237.0 million in outstanding borrowings under the Partnership's credit facility, leaving approximately $749.1 million available for future borrowing based on the borrowing capacity of $1.0 billion.

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

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

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

On March 12, 2014, the Partnership commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and on March 19, 2014, the Partnership made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, the Partnership delivered a notice of redemption for any and all outstanding 2018 Notes. All remaining outstanding 2018 Notes were redeemed on April 18, 2014 for $200.2 million, including accrued interest. The Partnership recorded a gain on extinguishment of debt related to the redemption of the 2018 Notes of $0.7 million for the year ended December 31, 2014.

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

On November 12, 2014, the Partnership issued $400 million aggregate principal amount of unsecured senior notes, consisting of $100.0 million aggregate principal amount of its 4.400% senior notes due 2024 (the "Additional 2024 Notes" and together with the Initial 2024 Notes, the "2024 Notes") and $300.0 million aggregate principal amount of its 5.050% senior notes due 2045 (the "2045 Notes," and, together with the 2018 Notes, 2019 Notes, 2022 Notes, 2024 Notes and 2044 Notes, the "Senior Notes"), at prices to the public of 104.007% and 99.452%, respectively, of their face value. The Additional 2024 Notes and the Initial 2024 Notes are treated as a single class of debt securities and have identical terms, other than the issue date. The 2045 Notes mature on April 1, 2045, and the interest payments on the 2045 Notes are due semi-annually in arrears in April and October.

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

Prior to March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2019 Notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the 2019 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 20 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2024 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 25 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2044 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2044, the Partnership may redeem all or a part of the 2045 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2045 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2045 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2044, the Partnership may redeem all or a part of the 2045 Notes at a redemption price equal to 100% of the principal amount of the 2045 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of our assets.

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

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures; and
- bankruptcy or other insolvency events involving us.

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

Other Borrowings. On December 31, 2014, E2 Energy Services, LLC, one of the Ohio services companies in which the Partnership invests, had certain promissory notes outstanding related to its vehicle fleet in the amount of $0.4 million due in increments through July 2017. The notes bear interest at fixed rates ranging 3.9% to 7.0%.

Credit Risk

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

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry's labor and material costs remained relatively unchanged in 2012, 2013 and 2014. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see “Item 1. Business—Environmental Matters” in Exhibit 99.1 to this Current Report on Form 8-K.

Contingencies

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

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

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

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

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. We are seeking to recover our losses related to the sinkhole from responsible parties. We have sued Texas Brine, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, but we have agreed to stay the matter pending resolution of our claims against Texas Brine and its insurers. In August 2014, we received a partial settlement with respect the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

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

In October 2014, Williams Olefins, L.L.C. filed a lawsuit against a subsidiary of the Partnership, EnLink NGL Marketing, LP, in the District Court of Tulsa County, Oklahoma. The plaintiff alleges breach of contract and negligent misrepresentation relating to an ethane output contract between the parties and the subsidiary's termination of ethane production from one of its fractionation plants. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

Disclosure Regarding Forward-Looking Statements

This Current Report on Form 8-K ("Current Report") contains forward-looking statements within the meaning of federal securities laws that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Current Report constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Current Report, the risk factors set forth in "Item 1A. Risk Factors" of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014 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

EnLink Midstream Partners, LP Financial Statements:

Report of Independent Registered Public Accounting Firm

The Partners
EnLink Midstream Partners, LP:

We have audited the accompanying consolidated balance sheets of EnLink Midstream Partners, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of EnLink Midstream Partners, LP and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

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

/s/ KPMG LLP

Dallas, Texas
May 28, 2015

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Balance Sheets

	December 31,	
	2014 (1)	2013
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9.6	$ —
Accounts receivable:		
Trade, net of allowance for bad debt	139.0	0.4
Accrued revenues and other	253.3	—
Related party	121.6	—
Fair value of derivative assets	16.7	—
Natural gas and natural gas liquids inventory, prepaid expenses and other	30.8	5.8
Assets held for disposition	—	72.7
Total current assets	571.0	78.9
Property and equipment, net of accumulated depreciation of $1,426.3 and $1,169.8, respectively	5,042.8	1,768.1
Intangible assets, net of accumulated amortization of $36.5	533.0	—
Goodwill	2,257.8	401.7
Fair value of derivative assets	10.0	—
Investments in unconsolidated affiliates	270.8	61.1
Other assets, net	16.6	—
Total assets	$ 8,702.0	$ 2,309.8
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 13.2	$ —
Accounts payable	108.6	1.7
Accounts payable to related party	3.0	—
Accrued gas, condensate and crude oil purchases	204.5	—
Contract liability	20.3	—
Accrued capital expenditures	22.6	—
Fair value of derivative liabilities	3.0	—
Accrued interest	16.9	—
Other current liabilities	90.0	38.8
Liabilities held for disposition	—	37.0
Total current liabilities	482.1	77.5
Long-term debt	2,022.5	—
Asset retirement obligations	12.4	7.7
Other long-term liabilities	84.0	—
Deferred tax liability	73.1	440.9
Fair value of derivative liabilities	2.0	—
Partners' equity:		
Predecessor	—	1,783.7
Common unitholders (245,421,549 units issued and outstanding at December 31, 2014)	5,833.3	—
General partner interest (1,594,974 equivalent units outstanding at December 31, 2014)	180.3	—
Non-controlling interest	12.3	—
Total partners' equity	6,025.9	1,783.7
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 8,702.0	$ 2,309.8

(1) Information has been recast to include results attributable to the 50% limited partner interest in Midstream Holdings (as defined below) (the “Transferred Interests”) acquired by the Partnership (as defined below) from Acacia (as defined below) and the VEX Interests (as defined below) acquired by the Partnership from Devon.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statements of Operations

	Years ended December 31,		
	2014 (1)	2013	2012
	(In millions, except per unit data)		
Revenues:			
Revenues	$ 2,412.7	$ 179.4	$ 153.9
Revenues - affiliates	1,073.0	2,116.5	1,753.9
Gain on derivatives	22.1	—	—
Total revenues	3,507.8	2,295.9	1,907.8
Operating costs and expenses:			
Purchased gas, NGLs, condensate and crude oil (2)	2,494.5	1,736.3	1,428.1
Operating expenses (3)	283.6	156.2	149.9
General and administrative (4)	94.5	45.1	41.7
Depreciation and amortization	284.3	187.0	145.4
Gain on sale of property	(0.1)	—	—
Impairments	—	—	16.4
Gain on litigation settlement	(6.1)	—	—
Total operating costs and expenses	3,150.7	2,124.6	1,781.5
Operating income	357.1	171.3	126.3
Other income (expense):			
Interest expense, net of interest income	(47.4)	—	—
Equity in income of equity investment	18.9	14.8	2.0
Gain on extinguishment of debt	3.2	—	—
Other expense	(0.5)	—	—
Total other income (expense)	(25.8)	14.8	2.0
Income from continuing operations before non-controlling interest and income taxes	331.3	186.1	128.3
Income tax provision	(22.0)	(67.0)	(46.2)
Net income from continuing operations	309.3	119.1	82.1
Discontinued operations:			
Income (loss) from discontinued operations, net of tax	1.0	(2.3)	(5.2)
Income from discontinued operations attributable to non-controlling interest, net of tax	—	(1.3)	(1.1)
Discontinued operations, net of tax	1.0	(3.6)	(6.3)
Net income	310.3	115.5	75.8
Net loss attributable to the non-controlling interest	(0.2)	—	—
Net income attributable to EnLink Midstream Partners, LP	$ 310.5	$ 115.5	$ 75.8
Predecessor interest in net income (5)	$ 35.5	$ —	$ —
General partner interest in net income	$ 138.3	$ —	$ —
Limited partners' interest in net income attributable to EnLink Midstream Partners, LP	$ 136.7	$ —	$ —
Net income attributable to EnLink Midstream Partners, LP per limited partners' unit:			
Basic common unit	$ 0.59	$ —	$ —
Diluted common unit	$ 0.59	$ —	$ —

(1) Financial information has been recast to include the financial position and results attributable to the Transferred Interests and VEX Interests.
(2) Includes $354.3 million, $1,588.2 million and $1,310.3 million for the year ended December 31, 2014, 2013 and 2012, respectively, of affiliate purchased gas.
(3) Includes $5.9 million, $36.2 million and $33.8 million for the year ended December 31, 2014, 2013 and 2012, respectively, of affiliate operating expenses.
(4) Includes $11.6 million, $45.1 million and $41.7 million for the year ended December 31, 2014, 2013 and 2012, respectively, of affiliate general and administrative expenses.
(5) Represents net income attributable to the Predecessor (as described below) for the periods prior to March 7, 2014.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statements of Changes in Partners' Equity

Years ended December 31, 2014, 2013 and 2012

	Common Units		General Partner Interest		Predecessor Equity	Non-Controlling Interest	
	$	Units	$	Units	$	$	Total
				(In millions)			
Balance, December 31, 2011	$ —	—	$ —	—	$ 1,856.0	$ 45.3	$ 1,901.3
Distributions from the Predecessor	—	—	—	—	21.5	—	21.5
Distributions from non-controlling interest	—	—	—	—	—	3.4	3.4
Net income	—	—	—	—	75.8	—	75.8
Balance, December 31, 2012	—	—	—	—	1,953.3	48.7	2,002.0
Distributions to the Predecessor	—	—	—	—	(285.1)	—	(285.1)
Distributions to non-controlling interest	—	—	—	—	—	(1.6)	(1.6)
Sale of non-controlling interest	—	—	—	—	—	(47.1)	(47.1)
Net income	—	—	—	—	115.5	—	115.5
Balance, December 31, 2013	—	—	—	—	1,783.7	—	1,783.7
Distributions to the Predecessor	—	—	—	—	(71.9)	—	(71.9)
Elimination of deferred taxes due to reorganization of predecessor	—	—	—	—	444.5	—	444.5
Issuance of units for reorganization of predecessor equity	1,095.9	120.5	—	—	(2,191.8)	1,095.9	—
Issuance of common units for acquisition of Partnership	3,329.6	109.1	48.7	1.6	—	—	3,378.3
Issuance of common units	412.0	14.6	—	—	—	—	412.0
Acquisition of interest in joint venture	31.0	1.0	—	—	—	7.2	38.2
Proceeds from exercise of unit options	0.4	0.1	—	—	—	—	0.4
Conversion of restricted units for common units, net of units withheld for taxes	(0.7)	0.1	—	—	—	—	(0.7)
Unit-based compensation	9.0	—	10.4	—	—	—	19.4
Distributions	(222.7)	—	(17.1)	—	—	—	(239.8)
Distributions to non-controlling interest	—	—	—	—	—	(159.5)	(159.5)
Non-controlling interest contributions	—	—	—	—	—	5.3	5.3
Acquisition of interest in Midstream Holdings (1)	936.4	—	—	—	—	(936.4)	—
Acquisition of VEX Interests (2)	105.7	—	—	—	—	—	105.7
Net income	136.7	—	138.3	—	35.5	(0.2)	310.3
Balance, December 31, 2014 (3)	$ 5,833.3	245.4	$ 180.3	1.6	$ —	$ 12.3	$ 6,025.9

(1) Financial information has been recast to include the financial position and results attributable to the Transferred Interests.

(2) Financial information has been recast to include the financial position and results attributable to the VEX Interests.

(3) Limited partner common units outstanding do not include Class D Common Units and Class E Common Units issued on February 17, 2015 and May 27, 2015, respectively, for the acquisition of the Transferred Interests.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2014 (1)	2013	2012
	(In millions)		
Cash flows from operating activities:			
Net income from continuing operations	$ 309.3	$ 119.1	$ 82.1
Adjustments to reconcile net income to net cash provided by operating activities, net of assets acquired or liabilities assumed:			
Depreciation and amortization	284.3	187.0	145.4
Asset impairments	—	—	16.4
Accretion expense	0.5	0.5	0.4
Gain on extinguishment of debt	(3.2)	—	—
Non-cash unit-based compensation	19.4	—	—
Gain on sale of property and other assets	(0.1)	—	—
Deferred tax expense (benefit)	15.3	35.5	(12.9)
Gain on derivatives recognized in net income	(22.1)	—	—
Cash settlements on derivatives	(0.3)	—	—
Amortization of debt issue costs	1.7	—	—
Amortization of premium on notes	(2.9)	—	—
Distribution of earnings from equity investments	7.0	10.9	0.4
Equity in income of equity investments	(18.9)	(14.8)	(2.0)
Changes in assets and liabilities:			
Accounts receivable, accrued revenue and other	(85.4)	—	—
Natural gas and natural gas liquids, prepaid expenses and other	(6.9)	0.7	(2.6)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(18.3)	(8.6)	(17.5)
Net cash provided by operating activities	479.4	330.3	209.7
Cash flows from investing activities:			
Additions to property and equipment	(796.0)	(244.3)	(337.2)
Acquisition of business	(421.1)	—	—
Proceeds from sale of property	0.1	—	—
Investment in limited liability company	(5.7)	—	(17.1)
Distribution from limited liability company in excess of earnings	10.9	1.1	1.9
Net cash used in investing activities	(1,211.8)	(243.2)	(352.4)
Cash flows from financing activities:			
Proceeds from borrowings	3,151.5	—	—
Payments on borrowings	(2,501.3)	—	—
Payments on capital lease obligations	(3.0)	—	—
Increase in drafts payable	10.2	—	(1.6)
Debt refinancing costs	(18.5)	—	—
Conversion of restricted units, net of units withheld for taxes	(0.7)	—	—
Proceeds from issuance of common units	412.0	—	—
Distributions to non-controlling interest	(159.5)	—	—
Contributions by non-controlling interest	6.3	—	—
Distribution to partners	(239.8)	—	—
Contributions by (distributions to) Predecessor	(21.3)	(151.2)	87.8
Contribution from Devon	105.7	—	—
Proceeds from exercise of unit options	0.4	—	—
Net cash provided by (used in) financing activities	742.0	(151.2)	86.2
Cash flow from discontinued operations:			
Net cash provided by operating activities	5.0	31.1	66.9
Net cash provided by (used in) investing activities	(0.6)	154.2	61.0
Net cash used in financing activities-net distributions to Devon and non-controlling interests	(4.4)	(136.8)	(63.9)
Net cash provided by discontinued operations	—	48.5	64.0
Net increase (decrease) in cash and cash equivalents	9.6	(15.6)	7.5
Cash and cash equivalents, beginning of period	—	15.6	8.1
Cash and cash equivalents, end of period	$ 9.6	$ —	$ 15.6
Cash paid for interest	$ 53.8	$ —	$ —
Cash paid for income taxes	$ 7.1	$ —	$ —

(1) Financial information has been recast to include the financial position and results attributable to the VEX Interests.

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Organization of Business and Nature of Business

EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (the “Partnership”) is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the NYSE under the symbol “ENLK.” Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.), a Delaware limited partnership (the “Operating Partnership”), and the subsidiaries of 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.” Devon Energy Corporation (“Devon”) owns ENLC's managing member and common units which represent approximately 70% of the outstanding limited liability company interests in ENLC.

Effective as of March 7, 2014, the Operating Partnership acquired (the “Acquisition”)50% of the outstanding equity interests in EnLink Midstream Holdings, LP (“Midstream Holdings”) and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units of limited partnership interests in the Partnership. At the same time, EnLink Midstream, Inc. (formerly known as Crosstex Energy, Inc.) (“EMI”), the entity that directly owns our General Partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the “business combination”). Prior to the drop downs described below, Acacia Natural Gas Corp I, Inc. ("Acacia"), a wholly-owned subsidiary of ENLC, owned 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.

On February 17, 2015, the Partnership acquired a 25% limited partner interest in Midstream Holdings (the “ February Transferred Interests”) from Acacia in a drop down transaction (the “February EMH Drop Down”). On May 27, 2015, the Partnership acquired the remaining 25% interest in Midstream Holdings (the "May Transferred Interests" and, together with the February Transferred Interests, the "Transferred Interests") from Acacia in a drop down transaction (the "May EMH Drop Down" and, together with the February EMH Drop Down, the "EMH Drop Downs") as described in Note (3)-Acquisitions. In addition, on April 1, 2015, the Partnership acquired the Victoria Express Pipeline and related truck terminal and storage assets from Devon (the "VEX Interests") as described in Note (3)-Acquisitions.

Due to ENLC's control of the Partnership through its ownership and control of the General Partner, and Devon's control of the Partnership through its ownership of the managing member of ENLC, the acquisitions are considered a transfer of net assets under common control. As such, the Partnership’s historical financial statements previously filed with the SEC have been recast in this Current Report on Form 8-K to include the results attributable to the Transferred Interests and VEX Interests from March 7, 2014, the date these entities were under common control.

The consolidated financial statements for periods prior to the Partnership’s acquisition of the assets from ENLC and Devon have been prepared from ENLC’s and Devon's historical cost-basis accounts for the acquired assets and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the acquired assets during the periods reported. Net income attributable to the assets acquired from ENLC and Devon for periods prior to the Partnership’s acquisition is allocated to the General Partner.

(b) Nature of Business

The Partnership primarily focuses on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing, to producers of natural gas, natural gas liquids (“NGLs”), crude oil and condensate. We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee-based arrangements. We provide a variety of crude oil and condensate services, which include crude oil and condensate gathering and transmission via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. We also have crude oil and condensate terminal facilities that provide access for crude oil and condensate producers to premium markets. Our gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. We also have transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants to our fractionators in south Louisiana. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport oil from a producer site to an end user. Our processing plants remove NGLs and CO2 from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“US GAAP”). Further, the consolidated financial statements give effect to the business combination and related transactions discussed above under the acquisition method of accounting and are treated as a reverse acquisition. Under the acquisition method of accounting, Midstream Holdings was the accounting acquirer in the transactions because its parent company, Devon, obtained control of the Partnership through the indirect control of the General Partner as a result of the business combination. Consequently, Midstream Holdings’ assets and liabilities retained their carrying values and are reflected in the balance sheet as of December 31, 2013 as the Predecessor. All financial results prior to March 7, 2014 reflect the historical operations of Midstream Holdings and its majority-owned subsidiaries and are reflected as Predecessor income on the statement of operations. Additionally, the Partnership’s assets acquired and liabilities assumed by Midstream Holdings in the business combination were recorded at their fair values measured as of the acquisition date, March 7, 2014. The excess of the purchase price over the estimated fair values of the Partnership’s net assets acquired was recorded as goodwill. Financial results subsequent to March 7, 2014 reflect the combined operations of Midstream Holdings and the Partnership and their majority-owned subsidiaries, which give effect to new contracts entered into with Devon and include the legacy Partnership assets. All significant intercompany transactions and balances have been eliminated. Certain assets were not contributed to Midstream Holdings from the Predecessor and the operations of such non contributed assets have been presented as discontinued operations. In conjunction with the business combination, Midstream Holdings became a non-taxable entity which was treated as a reorganization under common control with the removal of historical deferred taxes reflected through equity.

Prior year balances 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 Predecessor equity, in lieu of owner’s equity, in the consolidated financial statements.

During the prior year 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.

(b) Management's Use of Estimates

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

(c) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, NGLs, condensate or crude oil are delivered or at the time the service is performed at a fixed or determinable price. The Partnership generally accrues one month of sales and the related natural gas, NGL, condensate and crude oil purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the consolidated statement of operations in accordance with the Financial Accounting Standards Board Accounting Standards Codification ("FASB ASC") 605-45-45-1. Except for fee based arrangements, the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk. The Partnership accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

(d) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. The Partnership had imbalance payables of $1.5 million at December 31, 2014, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $1.2 million at December 31, 2014, which are carried at the lower of cost or market value. There were no imbalance payables or receivables at December 31, 2013.

(e) Cash, Cash Equivalents and Supplemental Information

The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

For the year ended December 31, 2014, we had non-cash financing activities of $31.2 million related to the issuance of Partnership units for the E2 drop down assets.

(f) Income Taxes

Certain of the Partnership's operations are subject to income taxes assessed by the federal and various state jurisdictions in the U.S. Additionally, certain of the Partnership'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. The Predecessor's operations prior to the merger on March 7, 2014 were subject to income taxes assessed by federal and various state jurisdictions.

The Partnership 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.

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

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

(h) Property, Plant, and Equipment

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

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

	December 31,	
	2014	2013
Transmission assets	$ 1,100.1	$ 95.9
Gathering systems	2,391.9	1,617.8
Gas processing plants	2,356.1	1,223.7
Other property and equipment	379.5	0.5
Construction in process	241.5	—
Property, plant and equipment	6,469.1	2,937.9
Accumulated depreciation and amortization	(1,426.3)	(1,169.8)
Property, plant and equipment, net	$ 5,042.8	$ 1,768.1

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

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

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

Depreciation expense of $247.8 million, $187.0 million and $145.4 million was recorded for the years ended December 31, 2014, 2013 and 2012, respectively.

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

Impairment Review. We evaluate our property, plant and equipment for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset's carrying value over its fair value. The fair values of long-lived assets are generally determined from estimated discounted future net cash flows. Our estimate of cash flows is based on assumptions which include (1) the amount of fee based services, the purchase and resale margins and the volume of natural gas, NGL, condensate and crude oil available to the asset, (2) markets available to the asset, (3) operating expenses, and (4) future natural gas, crude oil, condensate and NGL product prices. The volume of available natural gas, condensate, NGLs and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, condensate and crude oil prices. Projections of volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset. During 2012, the Predecessor recognized $16.4 million of asset impairment related to its continuing operations. The impairment resulted from the impact of lower natural gas and NGL prices on the Predecessor's Northridge system and is included in the Oklahoma segment.

(i) Equity Method of Accounting

The Partnership accounts for investments where it does not control the investment but has the ability to exercise significant influence using the equity method of accounting. Under this method, equity investments are initially carried at the acquisition cost, increased by the Partnership'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 Partnership 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.

(j) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership evaluates goodwill for impairment annually as of October 31st, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. The Partnership or Predecessor performed annual impairment tests of goodwill as of the fourth quarters of 2014, 2013 and 2012. Based on these assessments, no impairment of goodwill was required.

The table below provides a summary of the Partnership's goodwill, by assigned reporting unit.

	December 31, 2014	December 31, 2013
	(in millions)	
Texas	$ 1,168.2	$ 325.4
Louisiana	786.8	—
Oklahoma	190.3	76.3
Ohio River Valley	112.5	—
Total	$ 2,257.8	$ 401.7

The increase to the Partnership's goodwill in 2014 of $1.9 billion represents the goodwill recognized on the business combination with Midstream Holdings described in Note 3.

(k) Intangible Assets

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

The following table represents the Partnership's total purchased intangible assets at years ended December 31, 2014 (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$ 569.5	$ (36.5)	$ 533.0

The weighted average amortization period for intangible assets is 13.7 years. Amortization expense for intangibles was approximately $36.5 million for the year ended December 31, 2014.

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

2015	$ 44.5
2016	44.5
2017	44.5
2018	44.5
2019	43.6
Thereafter	311.4
Total	$ 533.0

(l) Asset Retirement Obligations

The Partnership 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 Partnership's retirement obligations include estimated environmental remediation costs which arise from normal operations and are associated with the retirement of the long-lived assets. The asset retirement cost is depreciated using the straight line depreciation method similar to that used for the associated property, plant and equipment. The Partnership provided an asset retirement obligation of $20.6 million and $7.7 million as of December 31, 2014 and 2013, respectively. $8.2 million of the provided asset retirement obligation as of December 31, 2014 is reflected in Other Current Liabilities.

(m) Other Long-Term Liabilities

Included in other current and long-term liabilities is an$80.7 million total liability related to an onerous performance obligation assumed in the business combination. The Partnership has one delivery contract which requires it to deliver a specified volume of gas each month at an indexed base price with a term to 2019. 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 recorded as a result of the March 7, 2014 business combination and was based on forecasted discounted cash obligations in excess of market under this gas delivery contract. The liability is reduced each month as delivery is made over the remaining life of the contract with an offsetting reduction in purchase gas costs.

(n) Derivatives

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

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

(o) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and commodity financial instruments. Management believes the risk is limited, other than the Partnership's exposure to Devon discussed below, since the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure of its marketing counter-parties and letters of credit or other appropriate security are obtained when considered necessary to limit the risk of loss. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had no reserve for uncollectible receivables as of December 31, 2014 and 2013.

During the year ended December 31, 2014, the Partnership had only one customer other than the affiliate transactions that individually represented greater than10.0% of its consolidated midstream revenues. The customer is located in the Louisiana segment and represented 11.0% of the consolidated revenues for year ended December 31, 2014. The affiliate transactions with Devon represented 30.6%, 92.2% and 91.9% of the consolidated midstream revenues for the years ended December 31, 2014, 2013 and 2012, respectively. As the Partnership continues to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. Devon and our Louisiana customer represent a significant percentage of revenues and the loss of either as a customer would have a material adverse impact on the Partnership's results of operations because the gross operating margin received from transactions with these customers are material to the Partnership.

(p) Environmental Costs

Environmental expenditures are expensed or capitalized depending on the nature of the expenditures and the future economic benefit. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the year ended December 31, 2014, 2013 and 2012 such expenditures were not material.

(q) Unit-Based Awards

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

The Partnership recognizes compensation cost related to all unit-based awards in its consolidated financial statements in accordance with FASB ASC 718. The Partnership and ENLC each have similar unit-based payment plans for employees. Unit-based compensation associated with ENLC's unit-based compensation plans awarded to directors, officers and employees of the General Partner of the Partnership are recorded by the Partnership since ENLC has no substantial or managed operating activities other than its interests in the Partnership and Midstream Holdings.

(r) Commitments and Contingencies

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

(s) Discontinued Operations

The Partnership classifies as discontinued operations its assets that have clearly distinguishable cash flows and are in the process of being sold or have been sold. The Partnership also includes as discontinued operations Predecessor assets that were not contributed in the business combination.

(t) Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-08, *Presentation of Financial Statements and Property, Plant and Equipment, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. This amendment has no impact on our current disclosures, but will in the future if we dispose of any individually significant components.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* (“ASU 2014-09”). ASU 2014-09 will replace existing revenue recognition requirements in US GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires significantly expanded disclosures regarding the qualitative and quantitative information of an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period and is to be applied retrospectively, with early application not permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures. Subject to this evaluation, we have reviewed all recently issued accounting pronouncements that became effective during the year ended December 31, 2014, and have determined that none would have a material impact on our Consolidated Financial Statements.

(u) Other Assets

Costs incurred in connection with the issuance of long-term debt are deferred and recorded as interest expense over the term of the related debt. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issue costs. Unamortized debt issuance costs totaling $16.6 million as of December 31, 2014 are included in other assets, net. Debt issuance costs are amortized into interest expense using the straight-line method over the term of the debt.

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

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

(3) Acquisitions

VEX Drop Down

On April 1, 2015, the Partnership acquired the VEX Interests from Devon in a drop down transaction (the "VEX Drop Down"). The aggregate consideration paid by the Partnership consisted of $171.0 million in cash, 338,159 common units representing limited partner interests in the Partnership with an aggregate value of approximately $9.0 million and the Partnership's assumption of up to $40.0 million in certain construction costs related to VEX. The VEX pipeline is a multi-grade crude oil pipeline located in the Eagle Ford shale in south Texas. Other VEX assets at the destination of the pipeline include a truck unloading terminal, above-ground storage and rights to barge loading docks. This acquisition has been accounted for as an acquisition under common control under ASC 805, resulting in the retrospective adjustment of our prior results.

EMH Drop Downs

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

On May 27, 2015, the Partnership acquired the remaining 25% limited partner interest in Midstream Holdings from Acacia in the May EMH Drop Down. As consideration for the May Transferred Interests, the Partnership issued 36.6 million Class E Common Units in the Partnership to Acacia with an implied value of $900.0 million. The Partnership's Class E Common Units are substantially similar in all respects to the Partnership's Common Units, except that they will only be entitled to a pro rata distribution for the fiscal quarter ended June 30, 2015. The Partnership's Class E Common Units will automatically convert into the Partnership's 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 June 30, 2015. After giving effect to the EMH Drop Downs, the Partnership owns 100% of Midstream Holdings.

Due to ENLC's control of the Partnership through its ownership and control of the General Partner, and Devon's control of the Partnership through its ownership of the managing member of ENLC, the acquisitions are considered a transfer of net assets under common control. As such, the Partnership's historical financial statements previously filed with the SEC have been recast in this Current Report on Form 8-K to include the results attributable to the Transferred Interests and VEX Interests from the date these entities were under common control.

The following table presents the collective impact of the VEX Drop Down and EMH Drop Downs on 2014 revenue, net income, net income attributable to non-controlling interest and net income attributable to EnLink Midstream Partners, LP as presented in the Partnership's historical Consolidated Statements of Operations:

	Year Ended December 31, 2014			
	Partnership Historical	EMH*	VEX**	Combined
	(in millions)			
Revenues	$ 3,500.4	$ —	$ 7.4	$ 3,507.8
Net income (loss)	$ 312.3	$ —	$ (2.0)	$ 310.3
Net income (loss) attributable to non-controlling interest	$ 131.2	$ (131.4)	$ —	$ (0.2)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 181.1	$ 131.4	$ (2.0)	$ 310.5
General partner interest in net income (loss)	$ 8.9	$ 131.4	$ (2.0)	$ 138.3

* The EMH 2014 amounts reflect the period from March 7, 2014 through December 31, 2014.

** The VEX amounts reflect the period from February 28, 2014 (the date VEX was acquired by Devon) through December 31, 2014.

Chevron acquisition

Effective November 1, 2014, the Partnership acquired, through one of its wholly owned subsidiaries, Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana for $234.0 million in cash, subject to certain adjustments. The natural gas assets include natural gas pipelines spanning from Beaumont, Texas to the Mississippi River corridor and working natural gas storage capacity in southern Louisiana. The Partnership paid cash of $231.5 million in November 2014 in cash.

The following table is a preliminary summary of the fair value of the assets acquired and liabilities assumed:

Purchase Price Allocation (in millions):	
Assets acquired:	
Property, Plant and equipment	$ 242.2
Liabilities assumed:	
Current liabilities	(10.7)
Total purchase price	$ 231.5

The purchase price allocation has been prepared on a preliminary basis pending receipt of a final valuation report and is subject to change. For the period from November 1, 2014 to December 31, 2014, the Partnership recognized $5.3 million of revenues and $4.9 million of operating expenses related to the assets acquired.

E2 Drop Down

On October 22, 2014, the Partnership acquired equity interests in E2 Appalachian Compression, LLC and E2 Energy Services, LLC (together “E2”) from EMI. The total consideration for the transaction is approximately $194.0 million, including a cash payment of $163.0 million and approximately 1.0 million Partnership units (valued at approximately $31.2 million based on the October 22, 2014 closing price of the Partnership's units). This acquisition has been accounted for as an acquisition under common control under ASC 805, resulting in the retrospective adjustment of our prior results.

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

Assets acquired:		
Current assets	$	25.4
Property, plant and equipment		136.7
Intangibles		41.9
Liabilities assumed:		
Current liabilities		(4.4)
Long term debt		(0.4)
Other long term liabilities		(0.4)
Total identifiable net assets	$	198.8

For the period from November 1, 2014 to December 31, 2014, the Partnership recognized $2.3 million of revenues and $1.8 million of operating expenses related to the assets acquired.

Devon Merger

On March 7, 2014, the Partnership acquired, through one of its wholly owned subsidiaries, 50% of the outstanding equity interests in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (the "Class B Units"). Midstream Holdings owns midstream assets in the Barnett Shale in North Texas and the Cana-Woodford and Arkoma-Woodford Shales in Oklahoma, as well as a contractual right to the economic burdens and benefits of Devon's 38.75% interest in Gulf Coast Fractionator ("GCF") in Mt. Belvieu, Texas.

Under the acquisition method of accounting, Midstream Holdings is the acquirer in the business combination because its parent company, Devon, obtained control of the Partnership through the indirect control of the General Partner. Consequently, Midstream Holdings' assets and liabilities retained their carrying values 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 measured as of the acquisition date. The excess of the purchase price over the estimated fair values of the Partnership's net assets acquired has been recorded as goodwill.

Since equity consideration was issued for this business combination, the purchase of these assets and liabilities has been excluded from our statement of cash flows, except for transaction related costs totaling $34.8 million assumed by the Partnership at closing and subsequently paid by the Partnership.

The following table summarizes the purchase price (in millions, except per unit price):

EnLink Midstream Partners, LP outstanding units:		
Common units held by public unitholders		75.1
Common units held by EMI		18.0
Preferred units held by third party (1)		17.1
Restricted units		0.4
Total units exchanged		110.6
EnLink Midstream Partners, LP common unit price (2)	$	30.51
EnLink Midstream Partners, LP common units fair value	$	3,374.4
EnLink Midstream Partners, LP outstanding unit options fair value	$	3.9
Total purchase price	$	3,378.3

(1) The Partnership converted the preferred units to common units in February 2014.

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

The following table is a summary of the fair value of the assets acquired and liabilities assumed from the Partnership in the business combination as of March 7, 2014:

Purchase Price Allocation (in millions):		
Assets acquired:		
Current assets	$	435.9
Property, plant and equipment		2,341.9
Intangibles		524.9
Equity investment		221.5
Goodwill		1,856.0
Other long-term assets		1.1
Liabilities assumed:		
Current liabilities		(474.0)
Long-term debt		(1,364.3)
Deferred taxes		(63.6)
Long term liabilities		(101.1)
Total purchase price	$	3,378.3

Goodwill recognized from the business combination primarily relates to the value created from additional growth opportunities and greater operating leverage in the Partnership's core areas. The goodwill is allocated among our Texas, Louisiana, Oklahoma, and ORV segments. All of the goodwill is non-deductible for tax purposes.

For the period from March 7, 2014 to December 31, 2014, the Partnership recognized $2,495.8 million of revenues and $2,447.4 million of operating expenses related to the assets acquired in the business combination.

Unaudited Pro Forma Information

The following unaudited pro forma condensed financial data for the year ended December 31, 2014 and 2013 gives effect to the business combination, Chevron acquisition, E2 drop down, EMH Drop Downs and VEX Drop Down as if they had occurred on January 1, 2013. The pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results. As of March 7, 2014, Midstream Holdings entered into gathering and processing agreements with Devon, which are described in Note 4. Pro forma financial information associated with the business combination and with these agreements with Devon is reflected below.

	Year Ended December 31,			
	2014		2013	
	(in millions except for per unit data)			
Pro forma total revenues	$	3,705.5	$	2,597.9
Pro forma net income	$	285.1	$	154.6
Pro forma net income attributable to EnLink Midstream Partners, LP	$	285.4	$	41.1
Pro forma net income per common unit:				
Basic	$	0.52	$	0.16
Diluted	$	0.52	$	0.16

(4) Affiliate Transactions

The Partnership engages in various transactions with Devon and other affiliated entities. Prior to March 7, 2014, these transactions relate to Predecessor transactions consisting of sales to and from affiliates, services provided by affiliates, cost allocations from affiliates and centralized cash management activities performed by affiliates. 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 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 contractual rights to the economic burdens and benefits of Devon's 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the business combination. Assets that were not contributed from the Predecessor are reflected as discontinued operations prior to March 7, 2014 and reflected as a reduction in equity at March 7, 2014. Further, the Predecessor's historical combined financial statements include U.S. federal and state income tax expense. As a result of the business combination, Midstream Holdings is a legal entity that is treated as a partnership for tax purposes and is not subject to U.S. federal income tax or certain state income taxes in the future. The business combination transactions were treated as a reorganization under common control for tax purposes. Therefore, the elimination of the related deferred tax liability is reflected as an increase in equity.

Midstream Holdings, in which the Partnership holds a 50% economic interest as of March 7, 2014, conducts business with Devon pursuant to the gathering and processing agreements described below. On February 17, 2015, the Partnership acquired the February Transferred Interest from Acacia, a wholly-owned subsidiary of ENLC, as described in Note (3)-Acquisitions. On May 27, 2015, the Partnership acquired the May Transferred Interest from Acacia as described in Note (3)-Acquisitions. In addition, on April 1, 2015, the Partnership acquired the VEX Interests from Devon as described in Note (3)-Acquisitions.

The legacy Partnership also historically has maintained a relationship with Devon as a customer, as described in more detail below.

Gathering and Processing Agreements

As described in Note 1, Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. In connection with the consummation of the business combination, EnLink Midstream Services, LLC, a wholly-owned subsidiary of Midstream Holdings ("EnLink Midstream Services"), entered into 10-year gathering and processing agreements with Devon pursuant to which EnLink Midstream Services provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon Gas Services, L.P., a subsidiary of Devon ("Gas Services") to Midstream Holdings' gathering and processing systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. SWG Pipeline, L.L.C. ("SWG Pipeline"), another wholly-owned subsidiary of Midstream Holdings, entered into a 10-year gathering agreement with Devon pursuant to which SWG Pipeline provides gathering, treating, compression, dehydration and redelivery services, as applicable, for natural gas delivered by Gas Services to another of the Partnership's gathering system in the Barnett Shale.

These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. Pursuant to the gathering and processing agreements, Devon has committed to deliver specified average minimum daily volumes of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales during each calendar quarter for a five-year period following execution. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

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

On August 29, 2014, Gas Services assigned its 10-year gathering and processing agreement to Linn Exchange Properties, LLC ("Linn Energy"), which is a subsidiary of Linn Energy, LLC, in connection with Gas Services' divestiture of certain of its southeastern Oklahoma assets. Such assignment was effective as of December 1, 2014. Accordingly, beginning on December 1, 2014, Linn Energy is responsible to perform Gas Services' obligations under the agreement, which remains in full force and effect. The assignment of this agreement relates to production dedicated to our Northridge assets in southeastern Oklahoma. Gross operating margin related to our Northridge assets totaled $28.4 million for the year ended December 31, 2014.

Historical Customer Relationship with Devon

As noted above, the Partnership maintained a customer relationship with Devon prior to the business combination pursuant to which certain of the Partnership's subsidiaries provide gathering, transportation, processing and gas lift services to Devon subsidiaries in exchange for fee-based compensation under several agreements with such Devon subsidiaries. The terms of these agreements vary, but the agreements expire between March 2015 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 the Partnership's subsidiaries has agreements with a subsidiary of Devon pursuant to which the Partnership's subsidiary purchases and sells NGLs and pays or receives, as applicable, a margin-based fee. These NGL purchase and sale agreements have month-to-month terms.

Transition Services Agreement

In connection with the consummation of the business combination, the Partnership entered into a transition services agreement with Devon pursuant to which Devon provides certain services to the Partnership with respect to the business and operations of Midstream Holdings, including IT, accounting, pipeline integrity, compliance management and procurement services, and the Partnership provides certain services to Devon and its subsidiaries, including IT, human resources and other commercial and operational services. Substantially all services under the transition services agreement were completed during 2014.

GCF Agreement

In connection with the closing of the business combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which 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% interest in GCF, which owns a fractionation facility in Mont Belvieu, Texas.

Lone Camp Gas Storage Agreement

In connection with the closing of the business combination, Midstream Holdings entered into an agreement with Gas Services under which Midstream Holdings provides gas storage services at its Lone Camp storage facility. Under this agreement, Gas Services reimburses Midstream Holdings for the expenses it incurs in providing the storage services. This agreement has minimal to no impact on Midstream Holdings' annual revenue.

Acacia Transportation Agreement

In connection with the closing of the business combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Midstream Holdings provides transportation services to Devon on its Acacia pipeline.

Office Leases

In connection with the closing of the business combination, the Operating Partnership entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which the Operating Partnership leases office space from Devon at its 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.

Tax Sharing Agreement

In connection with the closing of the business combination, 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.

The following presents financial information for the Predecessor's affiliate transactions and other transactions with Devon, all of which were settled through an adjustment to equity prior to March 7, 2014 (in millions):

	Year Ended December 31,		
	2014	2013	2012
Continuing Operations:			
Operating revenues - affiliates	$ (436.4)	$ (2,116.5)	$ (1,753.9)
Operating expenses - affiliates	340.0	1,669.5	1,385.8
Net affiliate transactions	(96.4)	(447.0)	(368.1)
Capital expenditures	16.2	244.3	337.2
Other third-party transactions, net	58.9	51.5	118.7
Net third-party transactions	75.1	295.8	455.9
Net cash distributions to Devon - continuing operations	(21.3)	(151.2)	87.8
Non-cash distribution of net assets to Devon	(6.3)	—	—
Total net distributions per equity	$ (27.6)	$ (151.2)	$ 87.8
Discontinued operations:			
Operating revenues - affiliates	$ (10.4)	$ (84.6)	$ (152.0)
Operating expenses - affiliates	5.0	32.7	86.3
Cash used in financing activities - affiliates	—	(5.6)	(1.1)
Net affiliate transactions	(5.4)	(57.5)	(66.8)
Capital expenditures	0.6	1.1	26.5
Other third-party transactions, net	0.4	(72.0)	(23.6)
Net third-party transactions	1.0	(70.9)	2.9
Net distributions to Devon and non-controlling interests - discontinued operations	(4.4)	(128.4)	(63.9)
Non-cash distribution of net assets to Devon	(39.9)	—	—
Total net distributions per equity	$ (44.3)	$ (128.4)	$ (63.9)
Total distributions- continuing and discontinued operations	$ (71.9)	$ (279.6)	$ 23.9

For the years ended December 31, 2014, 2013, 2012, Devon was a significant customer to the Partnership. Devon accounted for 30.6%, 92.2% and 91.9% of the Partnership's revenues for the year ended December 31, 2014, 2013 and 2012, respectively. The affiliate revenues after March 7, 2014 through December 31, 2014 were $636.6 million. The Partnership had an accounts receivable balance related to transactions with Devon of $121.6 million as of December 31, 2014. Additionally, the Partnership had an accounts payable balance related to transactions with Devon of $3.0 million as of December 31, 2014.

Share-based compensation costs included in the management services fee charged to Midstream Holdings by Devon were approximately $2.8 million for the year ended December 31, 2014 and $12.8 million for both 2013 and 2012. Pension, postretirement and employee savings plan costs included in the management services fee charged to the Partnership by Devon were approximately $1.6 million, $8.7 million and $9.1 million for the year ended December 31, 2014, 2013 and 2012 respectively. These amounts are included in general and administrative expenses in the accompanying statements of operations.

Transactions with ENLC

ENLC paid the Partnership $1.2 million during the year ended December 31, 2014 to cover its portion of administrative and compensation costs for officers and employees that perform services for ENLC. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for ENLC provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes and other benefit costs) is allocated to ENLC for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support and information service support.

(5) Long-Term Debt

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

	2014
Bank credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2014 was 1.9%	$ 237.0
Senior unsecured notes (due 2019), net of discount of $0.5 million, which bear interest at the rate of 2.70%	399.5
Senior unsecured notes (due 2022), including a premium of $21.9 million, which bear interest at the rate of 7.125%	184.4
Senior unsecured notes (due 2024), including a premium of $3.2 million, which bear interest at the rate of 4.40%	553.2
Senior unsecured notes (due 2044), net of discount of $0.3 million, which bear interest at the rate of 5.60%	349.7
Senior unsecured notes (due 2045), net of discount of $1.7 million, which bear interest at the rate of 5.05%	298.3
Other debt	0.4
Debt classified as long-term	$ 2,022.5

Maturities. Maturities for the long-term debt as of December 31, 2014 are as follows (in millions):

2015	$ 0.2
2016	0.1
2017	0.1
2018	—
2019	637.0
Thereafter	1,362.4
Subtotal	1,999.8
Less: premium (discount)	22.7
Total outstanding debt	$ 2,022.5

Credit Facility. On February 20, 2014, the Partnership entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “Partnership credit facility”). The Partnership credit facility will mature on the fifth anniversary of the initial funding date, which was March 7, 2014, unless the Partnership requests, and the requisite lenders agree, to extend it pursuant to its terms. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the 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 Partnership credit facility bear interest at the Partnership’s option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent’s prime rate) plus an applicable margin. The applicable margins vary depending on the Partnership’s credit rating. Upon breach by the Partnership of certain covenants governing the Partnership credit facility, amounts outstanding under the Partnership credit facility, if any, may become due and payable immediately. The Partnership expects to be in compliance with the covenants in the existing credit facility for at least the next twelve months.

As of December 31, 2014, there were $13.9 million in outstanding letters of credit and $237.0 million in outstanding borrowings under the Partnership’s credit facility, leaving approximately $749.1 million available for future borrowing based on the borrowing capacity of $1.0 billion.

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

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

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

On March 12, 2014, the Partnership commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and on March 19, 2014, the Partnership made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, the Partnership delivered a notice of redemption for any and all outstanding 2018 Notes. All remaining outstanding 2018 Notes were redeemed on April 18, 2014 for $200.2 million, including accrued interest. The Partnership recorded a gain on extinguishment of debt related to the redemption of the 2018 Notes of $0.7 million for the year ended December 31, 2014.

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

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

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

Prior to March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2019 Notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the 2019 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 20 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2024 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 25 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2044 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2044, the Partnership may redeem all or a part of the 2045 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2045 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2045 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2044, the Partnership may redeem all or a part of the 2045 Notes at a redemption price equal to 100% of the principal amount of the 2045 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of our assets.

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

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures;
- our default under other indebtedness that exceeds a certain threshold amount;
- failure 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.

Other Borrowings. On December 31, 2014, E2 Energy Services LLC ("E2 Services"), one of the Ohio services companies in which the Partnership invests, had certain promissory notes outstanding related to its vehicle fleet in the amount of $0.4 million due in increments through July 2017. The notes bear interest at fixed rates ranging from 3.9% to 7.0%.

(6) Income Taxes

The Predecessor's historical combined financial statements include U.S. federal and state income tax expense. As a result of the business combination, the Predecessor was reorganized and Midstream Holdings is treated as a partnership and not subject to federal or certain state income taxes subsequent to the March 7, 2014 transaction date. The elimination of Predecessor's related deferred federal and state income tax liabilities totaling $444.5 million is reflected through equity and treated as a reorganization under common control.

The Partnership is subject to the Texas margin tax consisting generally of a 1% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas.

Deferred tax liabilities also include $63.1 million related to the legacy Partnership's wholly-owned corporate entity that was formed to acquire the common stock of Clearfield Energy, Inc. and assumed the carryover tax basis of the ORV assets acquired from Clearfield. This deferred tax liability represents the future tax payable on the difference between the fair value and the tax basis of the assets acquired and is expected to become payable no later than 2027.

Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statement of operations, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each partner's tax attributes in us.

The Partnership provides for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis that will reverse in future periods (in millions).

	Years Ended December 31,		
	2014	2013	2012
Current income tax expense	$ 6.7	$ 31.5	$ 59.1
Deferred tax expense (benefit)	15.3	35.5	(12.9)
Total income tax expense	$ 22.0	$ 67.0	$ 46.2

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 (in millions):

	Years Ended December 31,		
	2014	2013	2012
Expected income tax expense based on federal statutory rate of 35%	$ 20.0	$ 65.1	$ 44.6
State income taxes, net of federal benefit and other	3.8	1.9	1.6
Other taxes (benefit)	(1.8)	—	—
Total income tax expense	$ 22.0	$ 67.0	$ 46.2

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 (in millions):

	Years Ended December 31,	
	2014	2013
Deferred income tax assets:		
Asset retirement obligations	$ —	$ 2.8
Other	—	0.4
Total deferred tax assets	—	3.2
Deferred tax liabilities:		
Property, plant and equipment	(73.1)	(444.1)
Total deferred tax liabilities	(73.1)	(444.1)
Deferred tax liability, net	$ (73.1)	$ (440.9)

A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in millions):

Balance as of December 31, 2013	$ —
Unrecognized tax positions assumed in merger	3.8
Decrease due to prior year tax positions	(2.0)
Increases due to current year tax positions	0.2
Balance as of December 31, 2014	$ 2.0

The $2.0 million decrease due to prior year tax positions mainly consists of unrecognized tax benefits assumed in the merger that expired in 2014. Unrecognized tax benefits as of December 31, 2014 of $2.0 million if recognized, would affect the effective tax rate. It is unknown when the remaining uncertain tax position will be resolved.

Per the Partnership's accounting policy election, $0.1 million of penalties and interest related to prior year tax positions was recorded to income tax expense in 2014. In the event interest or penalties are incurred with respect to income tax matters, the Partnership's policy will be to include such items in income tax expense. As of December 31, 2014, tax years 2011 through 2014 remain subject to examination by the Internal Revenue Service and tax years 2010 through 2014 remain subject to examination by various state taxing authorities.

(7) Partners’ Capital

(a) Issuance of Common Units

In November 2014, the Partnership issued 12,075,000 common units representing limited partner interests in the Partnership at an offering price of $28.37 per unit for net proceeds of $332.3 million. The net proceeds from the common units offering were used for capital expenditures and general partnership purposes.

In October 2014, the Partnership issued 1,016,322 common units to ENLC representing limited partner interests in the Partnership as partial consideration for E2 Appalachian Units.

In May 2014, the Partnership entered into an Equity Distribution Agreement (the “EDA”) with BMO Capital Markets Corp. (“BMOCM”). Pursuant to the terms of the EDA, the Partnership may from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Through December 31, 2014, the Partnership sold an aggregate of 2.4 million common units under the EDA, generating proceeds of approximately $71.9 million (net of approximately $0.7 million of commissions to BMOCM). The Partnership used the net proceeds for general partnership purposes.

In November 2014, the Partnership entered into an Equity Distribution Agreement (the “BMO EDA”) with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the “Sales Agents”) to sell up to $350.0 million in aggregate gross sales of the Partnership’s common units representing limited partner interests from time to time through an “at the market” equity offering program. The Partnership may also sell Common Units to any Sales Agent as principal for the Sales Agent’s own account at a price agreed upon at the time of sale. The Partnership has no obligation to sell any of the Common Units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. Through December 2014, the Partnership sold an aggregate of 0.3 million common units under the BMO EDA, generating proceeds of approximately $7.8 million (net of approximately $0.1 million of commissions). The Partnership used the net proceeds for general partnership purposes.

(b) Distributions

Unless restricted by the terms of the Partnership’s credit facility and/or the indentures governing the Partnership's unsecured senior notes, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions are made to the General Partner in accordance with its current percentage interest with the remainder to the common unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The Partnership's first quarter 2014 distribution on its common units and Class B Units of $0.36 per unit and $0.10 per unit, respectively, was paid on May 14, 2014. Distributions declared for the Class B Units represent a pro rata distribution for the number of days the Class B Units were issued and outstanding during the quarter. The Class B Units automatically converted into common units on a one-for-one basis on May 6, 2014. The Partnership declared a second quarter 2014 distribution on its common units of $0.365 per unit which was paid on August 13, 2014. The Partnership declared a third quarter 2014 distribution on its common units of $0.37 which was paid on November 13, 2014. Additionally, the Partnership declared a fourth quarter 2014 distribution on its common units of $0.375 per unit which was paid on February 12, 2015.

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

(c) Earnings per Unit and Dilution Computations

As required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. Net income earned by the Predecessor prior to March 7, 2014 is not included for purposes of calculating earnings per unit as the Predecessor did not have any unitholders. Net income attributable to the Transferred Interests and VEX Interests acquired from Acacia and Devon, respectively, for the period prior to the Partnership's acquisition of the Transferred Interests and VEX Interests are not allocated to the limited partners for purposes of calculating net income per common unit.

The following table reflects the computation of basic and diluted earnings per limited partner units for the periods presented (in millions except per unit amounts):

	Year Ended December 31, 2014*
Limited partners' interest in net income	$ 136.7
Distributed earnings allocated to:	
Common units and Class B Units (1) (2)	$ 310.0
Unvested restricted units	1.3
Total distributed earnings	$ 311.3
Undistributed loss allocated to:	
Common units and Class B Units (2)	$ (173.9)
Unvested restricted units	(0.7)
Total undistributed loss	$ (174.6)
Net income allocated to:	
Common units and Class B Units (2)	$ 136.1
Unvested restricted units	0.6
Total limited partners' interest in net income	$ 136.7
Total basic and diluted net income per unit:	
Basic	$ 0.59
Diluted	$ 0.59

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

(1) The 2014 amount represents distributions of $0.36 per unit paid on May 14, 2014, distributions of $0.365 per unit paid on August 13, 2014 , distributions of $0.37 per unit paid on November 13, 2014 and distributions declared of $0.375 per unit payable on February 12, 2015.

(2) The 2014 amount includes distribution of $0.10 per unit for Class B Units paid on May 14, 2014. The Class B Units converted into common units on a one-for-one basis on May 6, 2014.

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

	Year Ended December 31, 2014
Basic and diluted earnings per unit:	
Weighted average limited partner common units outstanding (1)	232.8
Diluted weighted average units outstanding:	
Weighted average limited partner basic common units outstanding (1)	232.8
Dilutive effect of restricted units issued	0.4
Total weighted average limited partner diluted common units outstanding (1)	233.2

(1) Weighted average limited partner common units outstanding do not include Class D Common Units and Class E Common Units issued on February 17, 2015 and May 27, 2015, respectively, in connection with the acquisitions of the Transferred Interests or the common units issued on April 1, 2015 in connection with the acquisition of the VEX Interests.

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented.

Net income is allocated to the General Partner in an amount equal to its incentive distribution rights as described in Note 7(b). The General Partner's share of net income consists of incentive distribution rights to the extent earned, a deduction for unit-based compensation attributable to ENLC’s restricted units and the percentage interest of the Partnership’s net income adjusted for ENLC's unit-based compensation specifically allocated to the General Partner. The net income allocated to the general partner is as follows (in millions):

	Year Ended December 31, 2014 (1)
Income allocation for incentive distributions	$ 20.6
Unit-based compensation attributable to ENLC’s restricted units	(10.4)
General Partner interest in net income	1.1
General Partner interest in E2, Transferred Interests and VEX Interests	127.0
General Partner share of net income	$ 138.3

(1) Financial information has been recast to include the financial position and results attributable to the Transferred Interests and VEX Interests.

(8) Asset Retirement Obligations

The schedule below summarizes the changes in the Partnership’s asset retirement obligations:

	December 31, 2014 (1)	December 31, 2013
	(in millions)	
Beginning asset retirement obligations	$ 7.7	$ 9.1
Revisions to existing liabilities	2.2	(1.8)
Liabilities acquired	10.2	—
Accretion	0.5	0.5
Liabilities settled	—	(0.1)
Ending asset retirement obligations	$ 20.6	$ 7.7

(1) Financial information has been recast to include the financial position and results attributable to the VEX Interests.

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

(9) Investment in Unconsolidated Affiliates

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

The following table shows the activity related to the Partnership's investment in unconsolidated affiliates for the periods indicated (in millions):

	Gulf Coast Fractionators		Howard Energy Partners (1)		Total	
December 31, 2014						
Distributions	$	11.0	$	12.7	$	23.7
Equity in income	$	17.1	$	1.8	$	18.9
December 31, 2013						
Distributions	$	12.0	$	—	$	12.0
Equity in income	$	14.8	$	—	$	14.8
December 31, 2012						
Distributions	$	2.3	$	—	$	2.3
Equity in income	$	2.0	$	—	$	2.0

(1) Includes income and distributions for the period from March 7, 2014 through December 31, 2014.

The following table shows the balances related to the Partnership's investment in unconsolidated affiliates for the periods indicated (in millions)

	December 31, 2014		December 31, 2013	
Gulf Coast Fractionators (1)	$	54.1	$	61.1
Howard Energy Partners		216.7		—
Total investments in unconsolidated affiliates	$	270.8	$	61.1

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

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership and ENLC each have similar unit or unit-based payment plans for employees, which are described below. Unit-based compensation associated with ENLC's compensation plan awarded to officers and employees of the Partnership are recorded by the Partnership since ENLC has no substantial or managed operating activities other than its interests in the Partnership and Midstream Holdings. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in millions):

	Year Ended December 31,		
	2014	2013	2012
Cost of unit-based compensation allocated to Predecessor general and administrative expense (1)	$ 2.8	$ 12.8	$ 12.8
Cost of unit-based compensation charged to general and administrative expense	16.7	—	—
Cost of unit-based compensation charged to operating expense	2.7	—	—
Total amount charged to income	$ 22.2	$ 12.8	$ 12.8

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

The Partnership accounts for unit-based compensation in accordance with FASB ASC 718, which requires that compensation related to all unit-based awards, including unit options, be recognized in the consolidated financial statements. On March 7, 2014, the General Partner amended and restated the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the "Plan") (formerly the Crosstex Energy GP, LLC Long-Term Incentive Plan). Amendments to the Plan included a change in name and other technical amendments. The Plan provides for the issuance of up to 9,070,000 awards.

(b) Restricted Incentive Units

The restricted incentive units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2014 is provided below:

EnLink Midstream Partners, LP Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	—	$ —
Assumed in business combination	371,225	30.51
Granted	768,989	31.47
Vested*	(62,428)	29.40
Forfeited	(55,595)	31.35
Non-vested, end of period	1,022,191	$ 31.25
Aggregate intrinsic value, end of period (in millions)	$ 29.7	

* Vested units include 24,314 units withheld for payroll taxes paid on behalf of employees.

Restricted incentive units assumed in the business combination were valued as of March 7, 2014, will vest at the end oftwo years. These units are included in the restricted incentive units outstanding and the current unit-based compensation cost calculations as of December 31, 2014. The Partnership issued restricted incentive units in 2014 to officers and other employees. These restricted incentive units typically vest at the end of three years.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the year ended December 31, 2014 are provided below (in millions):

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

As of December 31, 2014, there was $20.1 million of unrecognized compensation cost related to Partnership non-vested restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.9 years.

(c) Unit Options

During the year ended December 31, 2014, 37,432 unit options of the Partnership were exercised with an intrinsic value of $0.8 million. As of December 31, 2014, all unit options were fully vested and fully expensed.

(d) EnLink Midstream, LLC's Restricted Incentive Units

On February 5, 2014, ENLC's sole unitholder at the time, EnLink Midstream Manager, LLC, approved the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "Company Plan"). The Company Plan provides for the issuance of 11,000,000 awards.

On March 7, 2014, effective as of the closing of the business combination, ENLC (i) assumed the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan (the "2009 Plan") and all awards thereunder outstanding following the business combination and (ii) amended and restated the 2009 Plan to reflect the conversion of the awards under the 2009 Plan relating to EMI's common stock to awards in respect of common units of ENLC.

ENLC's restricted incentive units are valued at their fair value at the date of grant which is equal to the market value of the common units on such date. A summary of the restricted incentive unit activities for the year ended December 31, 2014 is provided below:

EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	—	$ —
Assumed in business combination	435,674	37.60
Granted	678,347	36.71
Vested*	(78,133)	37.64
Forfeited	(49,416)	36.75
Non-vested, end of period	986,472	$ 37.03
Aggregate intrinsic value, end of period (in millions)	$ 35.1	

* Vested shares include 31,093 units withheld for payroll taxes paid on behalf of employees.

Restricted incentive units assumed in the business combination were valued as of March 7, 2014, will vest at the end of two years. These units are included in restricted incentive units outstanding and the current unit-based compensation cost calculations as of December 31, 2014. ENLC issued restricted incentive units in 2014 to officers and other employees. These restricted incentive units typically vest at the end of three years and are included in restricted incentive units outstanding.

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2014 is provided below (in millions):

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

As of December 31, 2014, there was $20.5 million of unrecognized compensation costs related to ENLC non-vested restricted incentive units for directors, officers and employees. The cost is expected to be recognized over a weighted average period of 1.9 years.

(e) Benefit Plan

The Partnership sponsors a single employer 401(k) plan whereby it matches 100% of up to 6% of an employee's contribution. Contributions of $5.5 million were made to the plan for the year ended December 31, 2014.

(11) Derivatives

Interest Rate Swaps

The Partnership entered into interest rate swaps for 9 to 22 days in October and November during the year ended December 31, 2014 in connection with the issuance of the 2024 Notes and 2045 Notes in November 2014.

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as part of interest expense, net, as follows (in millions):

	December 31, 2014
Settlement gains on derivatives	$ 3.6

Commodity Swaps

The Partnership manages its exposure to fluctuation in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas, NGLs, condensate and crude oil. The Partnership does not designate transactions as cash flow or fair value hedges for hedge accounting treatment under FASB ASC 815. Therefore, changes in the fair value of the Partnership's derivatives are recorded in revenue in the period incurred. In addition, the risk management policy does not allow the Partnership to take speculative positions with its derivative contracts.

The Partnership commonly enters into index (float-for-float) or fixed-for-float swaps in order to mitigate its cash flow exposure to fluctuations in the future prices of natural gas, NGLs, condensate and crude oil. For natural gas, index swaps are used to protect against the price exposure of daily priced gas versus first-of-month priced gas. They are also used to hedge the basis location price risk resulting from supply and markets being priced on different indices. For natural gas, NGLs, condensate and crude oil, fixed-for-float swaps are used to protect cash flows against price fluctuations: 1) in the NGL component of our percentage of liquids contracts, which we receive as a fee for natural gas processing, 2) in the natural gas processing and fractionation components of our business and 3) in the storage component of our business where we have price risk for product held in inventory or storage.

The components of gain on derivatives in the consolidated statements of operations relating to commodity swaps are (in millions):

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

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

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

	December 31, 2014
Fair value of derivative assets — current	$ 16.7
Fair value of derivative assets — long term	10.0
Fair value of derivative liabilities — current	(3.0)
Fair value of derivative liabilities — long term	(2.0)
Net fair value of derivatives	$ 21.7

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes at December 31, 2014. The remaining term of the contracts extend no later than December 2016.

		December 31, 2014		
Commodity	**Instruments**	**Unit**	**Volume**	**Fair Value**
			(In millions)	
NGL (short contracts)	Swaps	Gallons	(57.0)	$ 26.3
NGL (long contracts)	Swaps	Gallons	45.4	(4.5)
Natural Gas (short contracts)	Swaps	MMBtu	(5.4)	0.3
Natural Gas (long contracts)	Swaps	MMBtu	3.1	(0.4)
Total fair value of derivatives				$ 21.7

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements (“ISDAs”) that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2014 of $26.7 million would be reduced to$21.7 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

Fair Value of Derivative Instruments

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

	Maturity Periods			
	Less than one year	**One to two years**	**More than two years**	**Total fair value**
December 31, 2014	$ 13.7	$ 8.0	$ —	$ 21.7

(12) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative contracts primarily consist of commodity swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

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

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

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income at each measurement date. The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value, thus, the estimates provided below are not necessarily indicative of the amount the Partnership could realize upon the sale or refinancing of such financial instruments (in millions):

	December 31, 2014	
	Carrying Value	Fair Value
Long-term debt	$ 2,022.5	$ 2,026.1
Obligations under capital lease	$ 20.3	$ 19.8

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership had $237.0 million in outstanding borrowings under its revolving credit facility as of December 31, 2014. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2014, the Partnership had borrowings totaling $399.5 million, $553.2 million, $349.7 million and $298.3 million, net of discount, under the 2019 Notes, 2024 Notes, 2044 Notes and 2045 Notes with a fixed rate of 2.70%, 4.40%, 5.60% and 5.05%, respectively. Additionally, the Partnership had borrowings of $184.4 million, including premium, under the 2022 Notes with a fixed rate of 7.125% as of December 31, 2014. The fair value of all senior unsecured notes as of December 31, 2014 was based on Level 2 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) Leases—Lessee

The Partnership has operating leases for office space, office and field equipment.

The following table summarizes the Partnership's remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

2015	$	11.6
2016		9.2
2017		6.6
2018		11.5
2019		9.0
Thereafter		71.2
	$	119.1

(b) Change of Control and Severance Agreements

Certain members of management of the Partnership are parties to change of control and/or severance agreements with the General Partner. The change of control and severance agreements provide those managers with severance payments in certain circumstances.

(c) Environmental Issues

The operation of pipelines, plants and other facilities for the gathering, processing, transmitting or disposing of natural gas, NGLs, crude oil, condensate, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, the Partnership 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 Partnership's results of operations, financial condition or cash flows.

(d) Litigation Contingencies

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

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

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

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

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. We are seeking to recover our losses from responsible parties. We have sued Texas Brine, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, but we have agreed to stay the matter pending resolution of our claims against Texas Brine and its insurers. In August 2014, we received a partial settlement with respect the Texas Brine claims in the amount of $6.1 million but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

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

In October 2014, Williams Olefins, L.L.C. filed a lawsuit against a subsidiary of the Partnership, EnLink NGL Marketing, LP, in the District Court of Tulsa County, Oklahoma. The plaintiff alleges breach of contract and negligent misrepresentation relating to an ethane output contract between the parties and the subsidiary’s termination of ethane production from one of its fractionation plants. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership’s costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

(14) Segment Information

Identification of operating segments is based principally upon regions served. The Partnership's reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in north Texas, south Texas and the Permian Basin in west Texas (“Texas”), the pipelines and processing plants located in Louisiana and NGL assets located in south Louisiana (“Louisiana”), natural gas gathering and processing operations located throughout Oklahoma (“Oklahoma”) and crude rail, truck, pipeline, and barge facilities in the Ohio River Valley (“ORV”). The VEX Interests are included with the Partnership's ORV crude operations for segment reporting for the year ended December 31, 2014. The Partnership's sales are derived from external domestic customers.

Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist primarily of cash, property and equipment, including software, for general corporate support, debt financing costs and its investments in HEP and GCF. Profit in the corporate segment for the year ended 2014 includes the operating activity for intersegment eliminations and gains on derivative activity. The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table:

	Texas	Louisiana	Oklahoma	ORV (1)	Corporate	Totals
			(In millions)			
Year Ended December 31, 2014 (2):						
Sales to external customers	$ 284.3	$ 1,852.3	$ 14.8	$ 261.3	$ —	$ 2,412.7
Sales to affiliates	782.9	73.2	304.0	7.4	(94.5)	1,073.0
Purchased gas, NGLs, condensate and crude oil	(490.9)	(1,754.2)	(142.5)	(201.4)	94.5	(2,494.5)
Operating expenses	(145.4)	(68.2)	(28.6)	(41.4)	—	(283.6)
Gain on litigation settlement	—	6.1	—	—	—	6.1
Gain on derivative activity	—	—	—	—	22.1	22.1
Segment profit	$ 430.9	$ 109.2	$ 147.7	$ 25.9	$ 22.1	$ 735.8
Depreciation, amortization and impairments	$ (125.9)	$ (69.3)	$ (49.4)	$ (37.0)	$ (2.7)	$ (284.3)
Goodwill	$ 1,168.2	$ 786.8	$ 190.3	$ 112.5	$ —	$ 2,257.8
Capital expenditures	$ 271.0	$ 273.1	$ 17.1	$ 183.6	$ 13.9	$ 758.7
Year Ended December 31, 2013:						
Sales to external customers	$ 129.3	$ —	$ 50.1	$ —	$ —	$ 179.4
Sales to affiliates	1,419.8	—	696.7	—	—	2,116.5
Purchased gas, NGLs, condensate and crude oil	(1,130.4)	—	(605.9)	—	—	(1,736.3)
Operating expenses	(121.2)	—	(35.0)	—	—	(156.2)
Segment profit	$ 297.5	$ —	$ 105.9	$ —	$ —	$ 403.4
Depreciation, amortization and impairments	$ (110.6)	$ —	$ (76.4)	$ —	$ —	$ (187.0)
Goodwill	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Capital expenditures	$ 147.0	$ —	$ 66.1	$ —	$ —	$ 213.1
Year Ended December 31, 2012:						
Sales to external customers	$ 124.4	$ —	$ 29.5	$ —	$ —	$ 153.9
Sales to affiliates	1,232.8	—	521.1	—	—	1,753.9
Purchased gas, NGLs, condensate and crude oil	(983.3)	—	(444.8)	—	—	(1,428.1)
Operating expenses	(119.8)	—	(30.1)	—	—	(149.9)
Segment profit	$ 254.1	$ —	$ 75.7	$ —	$ —	$ 329.8
Depreciation, amortization and impairments	$ (98.3)	$ —	$ (63.5)	$ —	$ —	$ (161.8)
Goodwill	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Capital expenditures	$ 142.4	$ —	$ 209.3	$ —	$ —	$ 351.7

(1) The crude oil operating activities attributable to the VEX Interests are included with ORV's crude oil activities for segment reporting.
(2) Financial information has been recast to include the financial position and results attributable to the VEX Interest.

The table below represents information about segment assets as of December 31, 2014 and 2013 (in millions):

	Years Ended December 31,	
Segment Identifiable Assets:	2014 (1)	2013
Texas	$ 3,302.9	$ 1,460.0
Louisiana	3,316.5	—
Oklahoma	892.8	777.1
ORV	871.8	—
Corporate	318.0	72.7
Total identifiable assets	$ 8,702.0	$ 2,309.8

(1) Financial information has been recast to include the financial position and results attributable to the VEX Interest.

The following table reconciles the segment profits reported above to the operating income as reported in the consolidated statements of operations (in millions):

	Years Ended December 31,		
	2014 (1)	2013	2012
Segment profits	$ 735.8	$ 403.4	$ 329.8
General and administrative expenses	(94.5)	(45.1)	(41.7)
Depreciation, amortization and impairments	(284.3)	(187.0)	(161.8)
Gain on sale of property	0.1	—	—
Operating income	$ 357.1	$ 171.3	$ 126.3

(1) Financial information has been recast to include the financial position and results attributable to the VEX Interest.

(15) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In millions, except per unit data)				
2014 (1):					
Revenues	$ 723.0	$ 927.2	$ 857.4	$ 1,000.2	$ 3,507.8
Operating income	$ 73.6	$ 91.4	$ 88.2	$ 103.9	$ 357.1
Net income attributable to the EnLink Midstream Partners, LP	$ 53.6	$ 81.8	$ 83.5	$ 91.6	$ 310.5
General partner interest in net income	$ 10.4	$ 43.5	$ 43.0	$ 41.4	$ 138.3
Limited partners' interest in net income attributable to EnLink Midstream Partners, LP	$ 7.7	$ 38.3	$ 40.5	$ 50.2	$ 136.7
Income per limited partner unit-basic	$ 0.03	$ 0.17	$ 0.18	$ 0.21	$ 0.59
Income per limited partner unit-diluted	$ 0.03	$ 0.17	$ 0.18	$ 0.21	$ 0.59
2013:					
Revenues	$ 526.9	$ 588.0	$ 578.2	$ 602.8	$ 2,295.9
Operating income	$ 35.9	$ 42.6	$ 48.1	$ 44.7	171.3
Net income attributable to EnLink Midstream Partners, LP	$ 29.4	$ 32.8	$ 30.3	$ 23.0	$ 115.5

(1) Financial information has been recast to include the financial position and results attributable to the Transferred Interests and VEX Interest.

(16) Discontinued Operations

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 contractual rights to the benefits and burdens associated with Devon's 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the business combination on March 7, 2014. Therefore, the Predecessor's non-contributed historical assets and liabilities are presented as held for sale as of December 31, 2013. All operations activity related to the non-contributed assets prior to March 7, 2014 are classified as discontinued operations.

The following schedule summarizes net income from discontinued operations (in millions):

	Years Ended December 31,		
	2014	2013	2012
Operating revenues:			
Operating revenues	$ 6.8	$ 42.1	$ 53.1
Operating revenues - affiliates	10.5	84.6	152.0
Total operating revenues	17.3	126.7	205.1
Operating expenses:			
Operating expenses:	15.7	130.3	213.2
Total operating expenses	15.7	130.3	213.2
Income (loss) before income taxes	1.6	(3.6)	(8.1)
Income tax provision (benefit)	0.6	(1.3)	(2.9)
Net income (loss)	1.0	(2.3)	(5.2)
Net income attributable to non-controlling interest	—	(1.3)	(1.1)
Net income (loss) including non-controlling interest	$ 1.0	$ (3.6)	$ (6.3)

The following table presents the main classes of assets and liabilities associated with the Partnership's discontinued operations at December 31, 2013. There were no assets and liabilities associated with discontinued operations at December 31, 2014:

	December 31, 2013
	(in millions)
Inventories	$ 0.2
Other current assets	0.2
Total current assets	0.4
Property, plant & equipment	72.3
Total assets	$ 72.7
Accounts payable	$ 3.2
Other current liabilities	1.1
Total current liabilities	4.3
Asset retirement obligations	7.1
Deferred income taxes	25.3
Other long-term liabilities	0.3
Total liabilities	$ 37.0

(17) Subsequent Events

Credit Facility Amendment. On February 5, 2015, the commitments under the Partnership credit facility were increased to$1.5 billion and the maturity date was extended by a year to March 6, 2020.

LPC Acquisition. On January 31, 2015, the Partnership, through one of its wholly owned subsidiaries acquired LPC Crude Oil Marketing LLC (“LPC”), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $100.0 million, subject to certain adjustments.