UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period from to

Commission file number: 001-36340
ENLINK MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
1722 Routh St., Suite 1300	
Dallas, Texas	**75201**
(Address of principal executive offices)	(Zip Code)

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

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

Title of Each Class	Name of Exchange on which Registered
None.	None.

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐
Emerging growth company ☐	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately $2.6 billion on June 30, 2018, based on $15.53 per unit, the closing price of the common units as reported on the New York Stock Exchange on such date.

At February 13, 2019, there were 144,535,672 common units outstanding, all of which were held by our affiliate, EnLink Midstream LLC.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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DEFINITIONS

The following terms as defined are used in this document:

Defined Term	**Definition**
/d	Per day.
2017 EDA	Equity Distribution Agreement entered into by ENLK in August 2017 with UBS Securities LLC, Barclays Capital Inc., BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc., and Wells Fargo Securities, LLC (collectively, the "Sales Agents") to sell up to $600.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program.
Acacia	Acacia Natural Gas Corp. I, Inc.
AMZ	Alerian MLP Index for Master Limited Partnerships.
ASC	The FASB Accounting Standards Codification.
ASC 606	ASC 606, *Revenue from Contracts with Customers.*
ASC 842	ASC 842, *Leases.*
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Marathon Petroleum Corporation in which ENLK owns a 50% interest and Marathon Petroleum Corporation owns a 50% interest. The Ascension JV, which began operations in April 2017, owns an NGL pipeline that connects ENLK's Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery.
ASU	The FASB Accounting Standards Update.
Avenger	Avenger crude oil gathering system, a crude oil gathering system in the northern Delaware Basin.
Bbls	Barrels.
Bcf	Billion cubic feet.
Black Coyote	Black Coyote crude oil gathering system, a crude oil gathering system in the STACK.
BLM	Bureau of Land Management.
Cedar Cove JV	Cedar Cove Midstream LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Kinder Morgan, Inc. in which ENLK owns a 30% interest and Kinder Morgan, Inc. owns a 70% interest. The Cedar Cove JV, which was formed in November 2016, owns gathering and compression assets in Blaine County, Oklahoma, located in the STACK play.
CFTC	U.S. Commodity Futures Trading Commission.
CNOW	Central Northern Oklahoma Woodford Shale.
CO_2	Carbon dioxide.
Consolidated Credit Facility	A $1.75 billion unsecured revolving credit facility entered into by ENLC that matures on January 25, 2024, which includes a $500.0 million letter of credit subfacility. The Consolidated Credit Facility was available upon closing of the Merger, and is guaranteed by ENLK.
CPI	Consumer Price Index.
Delaware Basin JV	Delaware G&P LLC, a joint venture between a subsidiary of ENLK and an affiliate of NGP in which ENLK owns a 50.1% interest and NGP owns a 49.9% interest. The Delaware Basin JV, which was formed in August 2016, owns the Lobo processing facilities located in the Delaware Basin in Texas.
Devon	Devon Energy Corporation.
ECP System	EnLink Crude Purchasing System. The ECP System includes assets that were acquired through the acquisition of LPC Crude Oil Marketing LLC in January 2015.
EMI	EnLink Midstream, Inc.
Enfield	Enfield Holdings, L.P.
ENLC	EnLink Midstream, LLC.
ENLC Class C common Units	A class of non-economic ENLC common units issued to Enfield immediately prior to the Merger equal to the number of Series B Preferred Units held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the "Partnership."
ENLK Credit Facility	A $1.5 billion unsecured revolving credit facility entered into by ENLK that would have matured on March 6, 2020, which included a $500.0 million letter of credit subfacility. The ENLK Credit Facility was terminated on January 25, 2019 in connection with the consummation of the Merger.
EOGP	EnLink Oklahoma Gas Processing, LP or EnLink Oklahoma Gas Processing, LP together with, when applicable, its consolidated subsidiaries. As of January 31, 2019, EOGP is wholly-owned by the Operating Partnership.
FASB	Financial Accounting Standards Board.

FERC	Federal Energy Regulatory Commission.
GAAP	Generally accepted accounting principles in the United States of America.
Gal	Gallons.
GCF	Gulf Coast Fractionators, which owns an NGL fractionator in Mont Belvieu, Texas. ENLK owns 38.75% of GCF.
GHG	Greenhouse gas.
GIP	Global Infrastructure Management, LLC, an independent infrastructure fund manager, itself, its affiliates, or managed fund vehicles, including GIP III Stetson I, L.P., GIP III Stetson II, L.P., and their affiliates.
GIP Transaction	On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP.
Goldman Sachs	Goldman Sachs Group, Inc.
Greater Chickadee	Crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin.
Gross Operating Margin	Revenue less cost of sales. Gross Operating Margin is a non-GAAP financial measure. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures” for other information.
HEP	Howard Energy Partners, LP. ENLK sold its 31% ownership interest in HEP in March 2017.
ISDAs	International Swaps and Derivatives Association Agreements.
Mcf	Thousand cubic feet.
MEGA system	Midland Energy Gathering Area system in Midland, Martin, and Glasscock counties, Texas.
Merger	On January 25, 2019, NOLA Merger Sub merged with and into ENLK with ENLK continuing as the surviving entity and a subsidiary of ENLC.
Merger Agreement	The Agreement and Plan of Merger, dated as of October 21, 2018, by and among ENLK, the general partner of ENLK, ENLC, the managing member of ENLC, and NOLA Merger Sub related to the Merger.
Midstream Holdings	EnLink Midstream Holdings, LP.
MMbbls	One million barrels.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP.
NOLA Merger Sub	NOLA Merger Sub, LLC, previously a wholly-owned subsidiary of ENLC prior to the Merger.
NTPL	North Texas Pipeline, a pipeline in North Texas that the Operating Partnership sold in December 2016.
NYSE	New York Stock Exchange.
Operating Partnership	EnLink Midstream Operating, LP, a Delaware limited partnership and wholly-owned subsidiary of ENLK.
ORV	ENLK’s Ohio River Valley crude oil, condensate stabilization, natural gas compression, and brine disposal assets in the Utica and Marcellus shales.
OTC	Over-the-counter.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins primarily in West Texas and New Mexico.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Redbud	Redbud crude oil gathering system, a crude oil gathering system in the STACK.
Series B Preferred Units	ENLK’s Series B Cumulative Convertible Preferred Units.
Series C Preferred Units	ENLK’s Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.
Term Loan	An $850.0 million term loan entered into by ENLK on December 11, 2018 with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto, which ENLC assumed in connection with the Merger and the obligations of which ENLK guarantees.
Thunderbird Plant	A gas processing plant in Central Oklahoma.
TPG	TPG Global, LLC.
VEX	ENLK’s Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in South Texas.

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 of capacity of 100 MMcf correlates to an approximate energy content of 100,000 MMBtu, although this correlation will vary depending on the composition of natural gas and is typically higher for unprocessed gas, which contains a higher concentration of NGLs. 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”).

ENLINK MIDSTREAM PARTNERS, LP

PART I

Item 1. Business

General

ENLK is a Delaware limited partnership formed in 2002. Our business activities are conducted through the Operating Partnership and the subsidiaries of the Operating Partnership. Our executive offices are located at 1722 Routh Street, Suite 1300, 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 ("SEC"): 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. Additionally, filings are available on the SEC's website (www.sec.gov). In this report, the term "Partnership," as well as the terms "ENLK," "our," "we," and "us" or like terms are sometimes used as references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership and EOGP.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is a direct, wholly-owned subsidiary of ENLC as successor-in-interest to EMI, which merged with and into ENLC on December 31, 2018. ENLC's units are traded on the NYSE under the symbol "ENLC." ENLC's managing member is a wholly-owned subsidiary of GIP.

The Business Combination with Devon

Effective as of March 7, 2014, the Operating Partnership acquired (the "Acquisition")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. At the same time, EMI became a wholly-owned subsidiary of ENLC (together with the Acquisition, the "Business Combination"). In 2015, the Operating Partnership acquired the remaining 50% of the outstanding equity interests in Midstream Holdings.

Midstream Holdings was formerly a wholly-owned subsidiary of Devon, and it gathers, processes, and transports natural gas, primarily for Devon. Midstream Holdings also fractionates 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.

EOGP Acquisition

On January 7, 2016, EOGP, an indirect subsidiary of ENLK, completed its acquisition of100% of the issued and outstanding membership interests of TOMPC LLC and TOM-STACK, LLC. As a result of the acquisition, the Operating Partnership acquired an 83.9% limited partner interest in EOGP, and ENLC acquired the remaining 16.1% limited partner interest in EOGP. On January 31, 2019,ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership in exchange for55,827,221 ENLK common units, resulting in the Operating Partnership owning 100% of the limited partner interests in EOGP.

GIP Transaction

On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP. As a result of the transaction:

- GIP, through GIP III Stetson I, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLK and the managing member of ENLC, which, as of the closing date, amounted to 100% of the outstanding limited liability company interests in the managing member of ENLC and approximately 23.1% of the outstanding limited partner interests in ENLK;

- GIP, through GIP III Stetson II, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLC, which, as of the closing date, amounted to approximately 63.8% of the outstanding limited liability company interests in ENLC; and

- Through this transaction, GIP acquired control of (i) the managing member of ENLC, (ii) ENLC, and (iii) ENLK, as a result of ENLC's ownership of ENLK's general partner.

Merger of EMI and Acacia

On December 31, 2018, EMI and Acacia merged with and into ENLC, with ENLC continuing as the surviving entity.

Simplification of the Corporate Structure

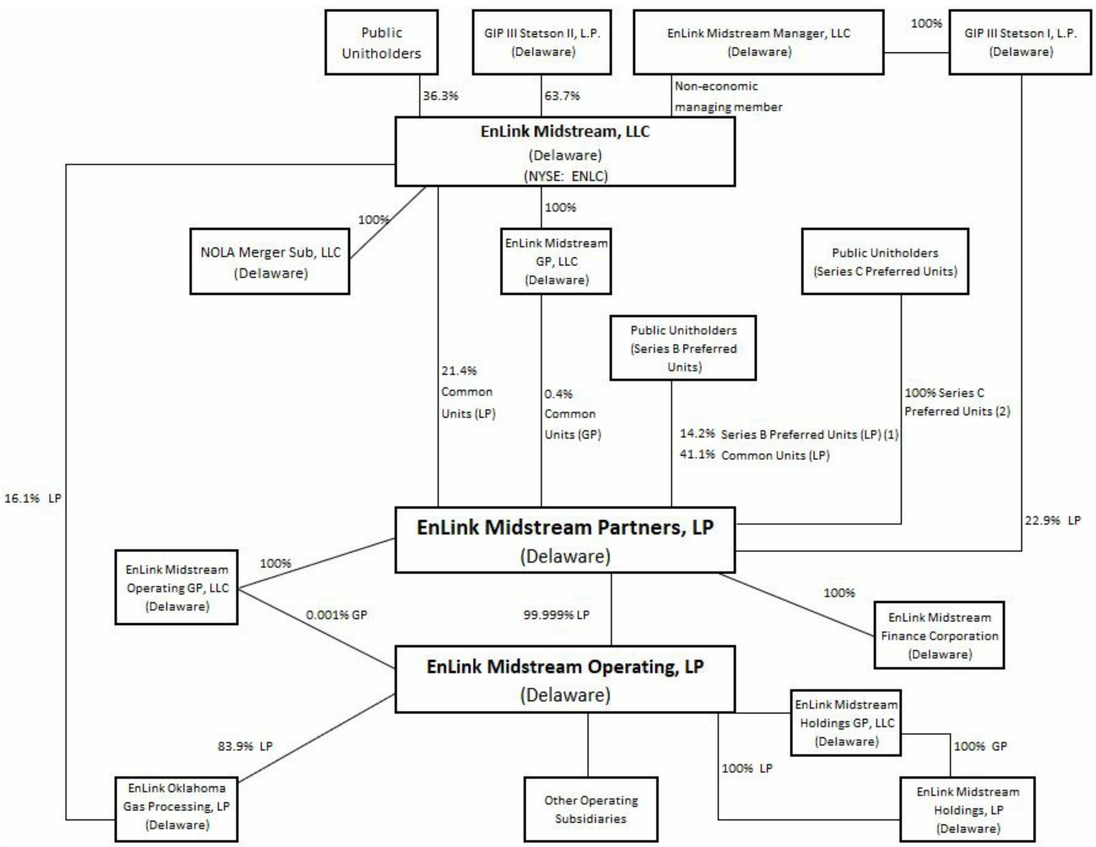
On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. See "Item 8. Financial Statements and Supplementary Data—Note 18—Subsequent Events" for more information on the Merger and related transactions.

As a result of the Merger, ENLC owns all of our outstanding common units. ENLC also owns our general partner and has the power to appoint all of the officers and directors of our general partner. ENLC is managed by its managing member, which is wholly-owned by GIP. Therefore, GIP indirectly controls our general partner, which has the sole authority to manage and operate our business. Accordingly, through its control of our general partner, GIP effectively has the ability to control our management.

Transfer of EOGP interest

On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership. See "Item 8. Financial Statements and Supplementary Data—Note 18—Subsequent Events" for more information regarding this transaction.

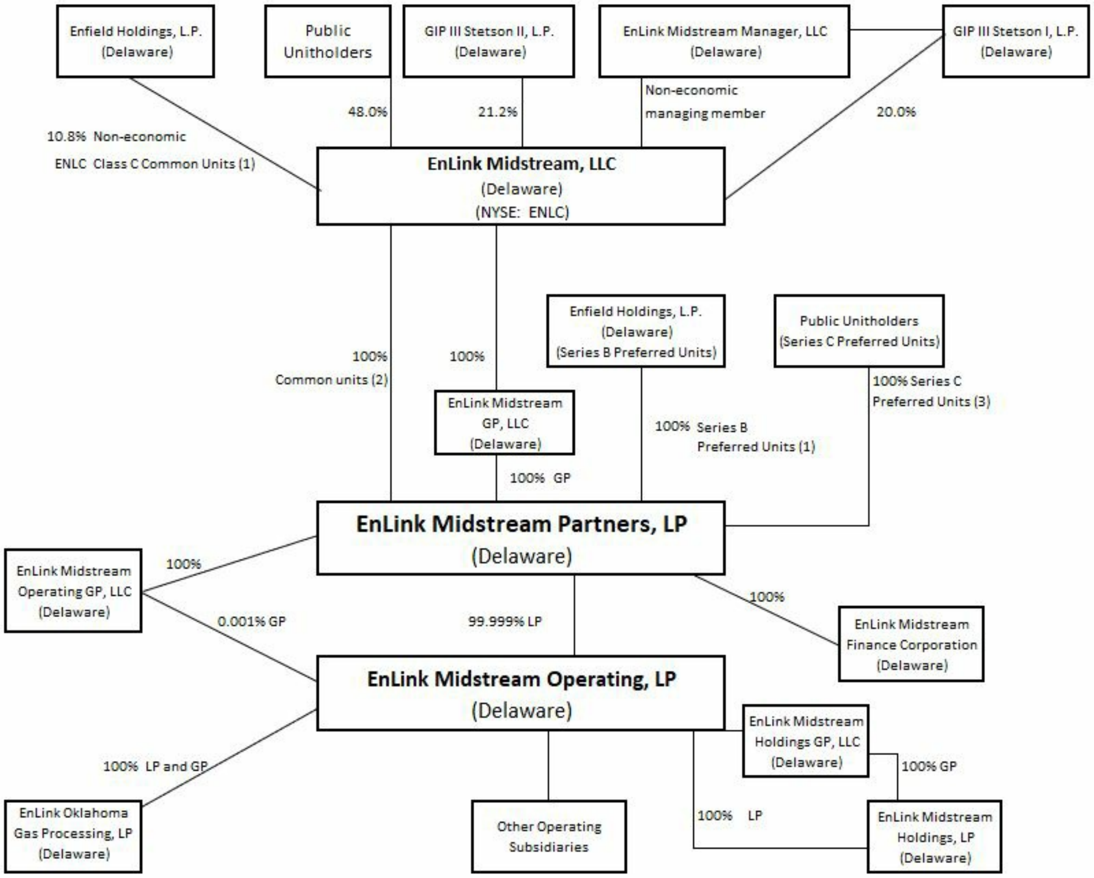
The following diagram depicts our organization and ownership as of December 31, 2018:



(1) The general partner ("GP") ownership percentage for ENLK accounts for general partner units, while the limited partner ("LP") ownership percentages for ENLK account for ENLK common units and Series B Preferred Units. Subsequent to the closing of the Merger, Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments.

(2) Series C Preferred Units are perpetual preferred units that are not convertible into other equity interests, and therefore, are not factored into the ENLK ownership calculations for the limited partner and general partner ownership percentages presented.

The following diagram depicts our organization and ownership as of February 1, 2019, after the close of the Merger and the transfer of the 16.1% limited partner interest in EOGP from ENLC to the Operating Partnership:



(1) Subsequent to the closing of the Merger, Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments. Upon the exchange of any Series B Preferred Units into ENLC common units, an equal number of the ENLC Class C Common Units will be canceled. As of February 1, 2019, the outstanding ENLC Class C Common Units represent a 10.8% membership interest in ENLC.
(2) All ENLK common units are held by ENLC. The Series B Preferred Units are entitled to vote, on a one-for-one basis (subject to certain adjustments) as a single class with ENLC, on all matters that require approval of the ENLK unitholders.
(3) Series C Preferred Units are perpetual preferred units that are not convertible into other equity interests, and therefore, are not factored into the ENLK ownership calculations for the limited partner and general partner ownership percentages presented.

Our Operations

We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.9 Bcf/d of processing capacity, seven fractionators with approximately 280,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

Our natural gas business includes connecting the wells of producers in our market areas to our gathering systems. Our gathering systems consist of networks of pipelines that collect natural gas from points at or near producing wells and transport it to our processing plants or to larger pipelines for further transmission. We operate processing plants that remove NGLs from the natural gas stream that is transported to the processing plants by our own gathering systems or by third-party pipelines. In conjunction with our gathering and processing business, we may purchase natural gas and NGLs from producers and other supply sources and sell that natural gas or NGLs to utilities, industrial consumers, marketers, and pipelines. Our transmission pipelines 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.

Our fractionators separate NGLs into separate purity products, including ethane, propane, isobutane, normal butane, and natural gasoline. Our fractionators receive NGLs primarily through our transmission lines that transport NGLs from East Texas and from our South Louisiana processing plants. Our fractionators also have the capability to receive NGLs by truck or rail terminals. We also have agreements pursuant to which third parties transport NGLs from our West Texas and Central Oklahoma operations to our NGL transmission lines that then transport the NGLs to our fractionators. In addition, we have NGL storage capacity to provide storage for customers.

Our crude oil and condensate business includes the gathering and transmission of crude oil and condensate via pipelines, barges, rail, and trucks, in addition to condensate stabilization and brine disposal. We also purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities to various markets.

Across our businesses, we primarily earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodities purchased. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal.

As of December 31, 2018, our assets are included in five primary segments:

- *Texas Segment.* The Texas segment includes our natural gas gathering, processing, and transmission operations in North Texas and the Permian Basin;

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering, processing, and transmission activities in the Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, STACK, and CNOW shale areas;

- *Louisiana Segment*. The Louisiana segment includes our natural gas pipelines, natural gas processing plants, storage facilities, fractionation facilities, and NGL assets located in Louisiana;

- *Crude and Condensate Segment.* The Crude and Condensate segment includes ORV, our crude oil operations in the Permian Basin and Central Oklahoma, and our crude oil activities associated with VEX; and

- *Corporate Segment*. The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our ownership interest in GCF in South Texas, and our general corporate property and expenses.

For more information about our segment reporting, see “Item 8. Financial Statements and Supplementary Data—Note 14—Segment Information.”

Our Business Strategies

Our primary business objective is to provide cash flow stability in our business while growing prudently and profitably. We intend to accomplish this objective by executing the following strategies:

- *Execute in our core growth areas.* We believe our assets are positioned in some of the most economically advantageous basins in the U.S., as well as key demand centers with growing end-use customers. We expect to grow certain of our systems organically over time by meeting our customers’ midstream service needs that result from their drilling activity in our areas of operation or growth in supply needs. We continually evaluate economically attractive organic expansion opportunities in our 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.

- *Maintain a strong financial position.* We believe that maintaining a conservative and balanced capital structure, appropriate leverage, and other key financial metrics will afford us better access to the capital markets at a competitive cost of capital. We also believe a strong financial position provides us the opportunity to grow our business in a prudent manner throughout the cycles in our industry.

- *Maintain stable cash flows supported by long-term, fee-based contracts.*We will seek to generate cash flows pursuant to long-term, firm contracts with creditworthy customers. We will continue to pursue opportunities to increase the fee-based components of our contract portfolio to minimize our direct commodity price exposure.

Our Competitive Strengths

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

- *Strategically-located assets*. The majority of our assets are strategically located in economically advantageous regions with the potential for increasing throughput volume and cash flow generation. Our asset portfolio includes gathering, transmission, fractionation, and processing systems that are located in the areas in which producer activity is focused on crude oil, condensate, and NGLs, as well as natural gas. We have established platforms in Texas, Oklahoma, and Louisiana, and we are focused on growing our operations in Central Oklahoma, the Permian Basin, and southern Louisiana through organic development and acquisitions.

- *Stable cash flows.* Approximately 88.3% of our gross operating margin for the year endedDecember 31, 2018 was generated from fee-based contract arrangements with minimal direct commodity price exposure. In addition, our cash flows are generated across a variety of products, services, and geographic locations and through transactions with a strong portfolio of customers with investment-grade credit ratings. We have approximately 10 years remaining on fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which we provide gathering, treating, compression, dehydration, stabilization, processing, and fractionation services, as applicable, for natural gas delivered by Devon to our gathering and processing systems in the Barnett and Cana-Woodford Shales. These agreements provide us with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas, and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. Additionally, our EOGP assets are supported by Devon with acreage dedications and MVCs for gathering and processing on Devon's STACK acreage through the end of 2020. We will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.

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

- *Experienced management team.* Our management team has deep experience in the energy industry and has a proven track record of creating value through the development, acquisition, optimization, and integration of midstream assets. 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."

Recent Developments

Simplification of the Corporate Structure. On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. See "Item 8. Financial Statements and Supplementary Data—Note 18—Subsequent Events" for more information on the Merger and related transactions.

Transfer of EOGP interest. On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership. See "Item 8. Financial Statements and Supplementary Data—Note 18—Subsequent Events" for more information regarding this transaction.

Strategic Partner Update. On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and ENLC's managing member to GIP. See "Item 8. Financial Statements and Supplementary Data—Note 1—Organization and Summary of Significant Agreements" for more information regarding the GIP Transaction.

Cajun-Sibon Pipeline. In 2018, we commenced an expansion of our Cajun-Sibon NGL pipeline capacity, which connects the Mont Belvieu NGL hub to our fractionation facilities in Louisiana. This is the third phase of our Cajun-Sibon system referred to as Cajun Sibon III, which will increase throughput capacity from 130,000 bbls/d to 185,000 bbls/d. We expect Cajun-Sibon III to be operational during the second quarter of 2019.

Avenger Crude Oil Gathering System. During 2018, we constructed a new crude oil gathering system in the northern Delaware Basin called Avenger. Avenger is supported by a long-term contract with Devon on dedicated acreage in their Todd and Potato Basin development areas in Eddy and Lea counties in New Mexico. We commenced initial operations on Avenger during the third quarter of 2018 and expect to begin full-service operations during the third quarter of 2019.

Central Oklahoma Plants. In December 2017, we commenced construction on our Thunderbird Plant to expand our Central Oklahoma processing capacity by an additional 200 MMcf/d gas processing plant. We expect to begin operations on the Thunderbird Plant during the second quarter of 2019.

Central Oklahoma Crude Oil Gathering Systems. In late March 2018, we completed construction of the first phase of Black Coyote. Black Coyote expands our operations in the core of the STACK play in Central Oklahoma and was built primarily to service acreage dedicated from Devon, which is the anchor customer on the system. In addition, we further expanded our crude oil gathering operations in the STACK through the construction of Redbud, which is supported by a contract with Marathon Oil Company. We commenced initial operations on Redbud during the third quarter of 2018.

Lobo Natural Gas Gathering and Processing Facilities. During the second quarter of 2018, we completed construction of an expansion to our Lobo II cryogenic gas processing plant, which brought total operational processing capacity at our Lobo facilities to 175 MMcf/d. We further expanded our natural gas processing capacity at our Lobo facilities through the construction of the Lobo III cryogenic gas processing plant, which was completed during the fourth quarter of 2018. Lobo III provides an additional 100 MMcf/d of operational capacity. An additional 100 MMcf/d of operational capacity will be completed during the first quarter of 2019.

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, 2018:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (HP) (1)	Estimated Capacity (2)	Year Ended December 31, 2018 Average Throughput (3)
Gas Pipelines				
Texas assets:				
Bridgeport rich and lean gathering systems	2,800	186,300	861	775,000
Johnson County gathering system	390	53,800	589	120,200
Silver Creek gathering system	600	69,000	522	303,300
Acacia transmission system	130	16,000	920	534,600
North Texas assets	3,920	325,100	2,892	1,733,100
MEGA System gathering facilities	730	115,400	413	330,400
Lobo gathering system (4)	155	30,200	155	192,300
Permian Basin gas assets (4)	885	145,600	568	522,700
Texas assets	4,805	470,700	3,460	2,255,800
Oklahoma assets:				
Central Oklahoma gathering system	1,755	258,700	1,137	1,168,300
Northridge gathering system	140	14,000	65	36,400
Oklahoma assets	1,895	272,700	1,202	1,204,700
Louisiana assets:				
Louisiana gas gathering and transmission system	3,220	97,400	3,975	2,196,200
Total Gas Pipelines	9,920	840,800	8,637	5,656,700
NGL, Crude Oil and Condensate Pipelines				
Louisiana assets:				
Cajun-Sibon NGL pipeline system	760	—	130,000	139,800
Ascension NGL pipeline (5)	35	—	50,000	21,700
Louisiana assets	795	—	180,000	161,500
Crude and condensate assets:				
Central Oklahoma crude oil gathering systems	85	—	160,000	10,100
Ohio River Valley (6)	210	—	25,650	18,600
Victoria Express Pipeline	60	—	90,000	14,600
Permian Basin gathering (7)	390	—	136,500	115,300
Total NGL, Crude Oil and Condensate Pipelines	1,540	—	592,150	320,100

(1) Includes power generation units.
(2) Estimated capacity for gas pipelines is MMcf/d. A volume capacity of 100 MMcf/d correlates to an approximate energy content of 100,000 MMBtu/d. Estimated capacity for liquids and crude and condensate pipelines is Bbls/d.
(3) Average throughput for gas pipelines is MMBtu/d. Average throughput for NGL, crude, and condensate pipelines is Bbls/d.
(4) Includes gross mileage, compression, capacity, and throughput for the Delaware Basin JV, which is owned 50.1% by us. Estimated capacity on our Lobo gathering system includes only the Delaware Basin JV's compression capacity and does not include gas compressed by third parties on our system.
(5) Includes gross mileage, capacity, and throughput for the Ascension JV, which is owned 50% by us.
(6) Estimated capacity is comprised of trucking capacity only.
(7) Estimated capacity is comprised of 86,500 Bbls/d of pipeline capacity and 50,000 Bbls/d of trucking capacity. Our Permian Basin gathering crude and condensate assets include the ECP system, Greater Chickadee system, and Avenger system.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2018 Average Throughput (MMBtu/d)
Texas assets:		
Bridgeport processing facility	800	576,300
Silver Creek processing system	280	171,100
North Texas assets	1,080	747,400
MEGA system processing facilities	408	344,800
Lobo processing facilities	275	186,900
Permian Basin assets	683	531,700
Texas assets	1,763	1,279,100
Oklahoma Assets:		
Central Oklahoma processing facilities	1,045	1,102,000
Northridge processing facility	200	93,300
Oklahoma assets	1,245	1,195,300
Louisiana assets:		
Louisiana gas processing facilities	1,903	431,200
Total Processing Facilities	4,911	2,905,600

Fractionation Facilities	Estimated NGL Fractionation Capacity (Bbls/d)	Year Ended December 31, 2018 Average Throughput (Bbls/d)
Louisiana assets:		
Plaquemine fractionation facility (1)	117,000	70,100
Plaquemine processing plant	11,000	5,000
Eunice fractionation facility	65,000	50,800
Riverside fractionation facility (1)	—	30,900
Louisiana assets	193,000	156,800
Texas assets:		
Bridgeport processing facility (2)	15,000	—
Mesquite terminal (2)	15,000	—
Texas assets	30,000	—
Gulf Coast Fractionators (3)	56,000	45,100
Total Fractionation Facilities	279,000	201,900

(1) The Plaquemine fractionation facility produces purity ethane and propane for sale to markets via pipeline, while butane and heavier products are sent to the Riverside fractionation facility for further processing. The Plaquemine fractionation facility and the Riverside fractionation facility have an aggregate fractionation capacity of 117 MBbls/d.

(2) We have two fractionation facilities with capacity of 15 MBbls/d each. Our Mesquite terminal in the Permian Basin and our Bridgeport processing plant in North Texas provide operational flexibility for the related processing plants but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under our current contracts, we do not earn fractionation fees for operating these facilities, so throughput volumes through these facilities are not captured on a routine basis and are not significant to our gross operating margins.

(3) Volumes shown reflect our 38.75% ownership in Gulf Coast Fractionators.

Storage Assets	Estimated Storage Capacity (1)
Gas storage:	
Belle Rose gas storage facility	11.9
Sorrento gas storage facility	7.3
Total gas storage	19.2
NGL storage:	
Napoleonville NGL storage facility	5.0
Crude oil storage:	
ORV storage	0.5
Permian storage	0.1
Central Oklahoma storage	0.2
VEX storage	0.2
Total crude oil storage	1.0

(1) Estimated capacity for gas storage is Bcf and includes linefill capacity necessary to operate storage facilities. Estimated capacity for NGL and crude oil storage is MMbbls.

Texas Assets. Our Texas assets include transmission pipelines, processing facilities, and gathering systems in the Barnett Shale in North Texas and the Permian Basin in West Texas.

- Acacia Transmission System. The Acacia transmission system is a 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. Devon is the largest customer on the Acacia pipeline with approximately five years remaining on a fixed-fee transportation agreement that covers transmission services and includes annual rate escalators.

- Processing and Fractionation Facilities. Our processing facilities in Texas include 11 gas processing plants and consist of the following:

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

        - *Bridgeport processing facility.* Our Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants. Devon is the Bridgeport facility's largest customer, providing substantially all of the natural gas processed for the year ended December 31, 2018. We have extended our fixed-fee processing agreement with Devon, which was effective after the GIP Transaction, and currently have approximately 10 years remaining on our agreement with Devon pursuant to which we provide processing services for natural gas delivered by Devon to the Bridgeport processing facility.

        - *Silver Creek processing system.* Our Silver Creek processing system, located in Weatherford, Azle, and Fort Worth, Texas, includes three processing plants: the Azle plant, the Silver Creek plant, and the Goforth plant, which account for 50 MMcf/d, 200 MMcf/d, and 30 MMcf/d of processing capacity, respectively. During 2018, we idled the Azle and GoForth plants due to decreased volumes. Currently, the processing capacity at the Silver Creek plant is sufficient to process all gas on the Silver Creek processing system.

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

        - *MEGA system processing facilities.* Our MEGA system natural gas processing facilities are located in Midland, Martin, and Glasscock counties, Texas and operate as a connected system. These assets consist of the Bearkat processing facility with a capacity of 75 MMcf/d, the Deadwood processing facility with a capacity of 58 MMcf/d, the Midmar processing facilities with a capacity of 175 MMcf/d, and the Riptide processing facility with a capacity of 100 MMcf/d.

- *Lobo processing facilities*. Our Lobo natural gas processing facilities are located in Loving County, Texas and include three processing plants, Lobo I, Lobo II, and Lobo III, which account for 35 MMcf/d, 140 MMcf/d, and 100 MMcf/d of processing capacity, respectively. The Lobo processing facilities and the connected gathering system are owned by the Delaware Basin JV.

- Gathering Systems. Our gathering systems in Texas are connected to our North Texas or Permian Basin processing assets.
  - *North Texas Assets.* Our North Texas gathering systems include the following:
    - *Bridgeport rich gas gathering system.* A substantial majority of the natural gas gathered on the Bridgeport rich gas gathering system is delivered to the Bridgeport processing facility. Devon is the largest customer on the Bridgeport rich gas gathering system contributing substantially all of the natural gas gathered for the year ended December 31, 2018. As described above, we have extended our fixed-fee gathering agreement with Devon, which was effective after the GIP Transaction, and currently have approximately 10 years remaining on a fixed-fee gathering agreement with Devon pursuant to which we provide gathering services on the Bridgeport system.
    - *Bridgeport lean gas gathering system.* Natural gas gathered on the Bridgeport lean gas gathering system is primarily attributable to Devon and is delivered to the Acacia transmission system and to intrastate pipelines without processing. As described above, we are party to a fixed-fee gathering and processing agreement with Devon that covers gathering services on the Bridgeport system.
    - *Johnson County gathering system*. Natural gas gathered on this system is primarily attributable to one customer with whom we have a fixed-fee processing agreement that currently has approximately five years remaining.
    - *Silver Creek gathering system*. Our Silver Creek gathering system is located primarily in Hood, Parker, and Johnson counties, Texas, and connects to the Silver Creek processing system.
  - *Permian Basin assets*. Our Permian Basin gathering systems include the following:
    - *MEGA system gathering facilities*. This gathering system in the Permian Basin serves as an interconnected system of pipelines and compressors to deliver gas from wellheads in the Permian Basin to the MEGA system processing facilities.
    - *Lobo gathering system.* This rich natural gas gathering system consists of gathering pipeline and compression assets in the Delaware Basin in Texas and New Mexico. The Lobo gathering system is owned by the Delaware Basin JV.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities and gathering systems in Southern and Central Oklahoma.

- Oklahoma processing system. Our processing facilities include the following:
  - *Central Oklahoma processing facilities.* The Central Oklahoma plants include the Chisholm plants, the Battle Ridge plant, and the Cana processing facilities (collectively, the “Central Oklahoma processing system”), which account for 560 MMcf/d, 85 MMcf/d, and 400 MMcf/d of processing capacity, respectively. The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners, LP and an affiliate of ONEOK, Inc. (“ONEOK”). The unprocessed NGLs from the Chisholm facilities are transported by ONEOK to NGL transmission lines, which then transport the NGLs to our fractionators in Louisiana. Devon is the primary customer of the Cana processing facilities. We have extended our fixed-fee processing agreement with Devon, which was effective after the GIP Transaction, and currently have approximately 10 years remaining on a fixed-fee gathering and processing agreement with us pursuant to which we provide processing services for natural gas delivered by Devon to the Cana processing facility. Additionally, we have

a contractual arrangement with Devon on the Chisholm plants that includes an MVC that will remain in effect until December 2020. For 2019, the MVC dictates that approximately 185 MMcf/d of natural gas will be delivered to the Chisholm plant processing facility. The MVC escalates quarterly, resulting in approximately 230 MMcf/d to be delivered in 2020.

    - *Northridge processing facility.* Our Northridge processing plant is located in Hughes County in the Arkoma-Woodford Shale in Southeastern Oklahoma. The residue natural gas from the Northridge processing facility is delivered to CenterPoint Energy, Inc., Enable Midstream Partners, LP, and MPLX LP.

- <u>Oklahoma gathering system.</u> Our Oklahoma gathering systems include the following:

    - *Central Oklahoma gathering system.* The Central Oklahoma gathering system serves the STACK and CNOW plays. In addition, our contractual arrangement with Devon includes an MVC that will remain in effect until December 2020. For 2019, the MVC dictates that approximately 185 MMcf/d of natural gas will be delivered through the Chisholm gathering system. The MVC escalates quarterly, resulting in approximately 230 MMcf/d to be delivered in 2020.

    - *Northridge gathering system.* Our Northridge gathering system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma.

Louisiana Assets. Our Louisiana assets consist of gas and NGL transmission pipelines, processing facilities, gathering systems, and gas and NGL storage.

- <u>Louisiana Gas Pipeline and Processing Systems.</u> The Louisiana gas pipeline system includes gathering and transmission systems, processing facilities, and underground gas storage.

    - *Gas Transmission and Gathering Systems.* Our transmission system consists of a portfolio of large capacity interconnections with the Gulf Coast pipeline grid that provides customers with supply access to multiple domestic production basins for redelivery to major industrial market consumption located primarily in the Mississippi River Corridor between Baton Rouge, Louisiana and New Orleans, Louisiana. Our natural gas transmission services are supplemented by fully integrated, high deliverability salt dome storage capacity strategically located in the natural gas consumption corridor. In combination with our transmission system, our gathering systems provide a fully integrated wellhead to burner tip value chain that includes local gathering, processing, and treating services to Louisiana producers.

    - *Gas Processing and Storage Facilities.* Our processing facilities in Louisiana include six gas processing plants, of which three are currently operational.

        - *Plaquemine Processing Plant.* The Plaquemine processing plant has 225 MMcf/d of processing capacity and is connected to the Plaquemine fractionation facility.

        - *Gibson Processing Plant.* The Gibson processing plant has 110 MMcf/d of processing capacity and is located in Gibson, Louisiana. The Gibson processing plant is connected to our Louisiana gathering system.

        - *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. The Pelican processing plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline. This plant has an interconnection with the Louisiana gas pipeline system allowing us to process natural gas from this system at our Pelican processing 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 gas processing plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. Our share of the plant’s capacity is approximately 193 MMcf/d. The plant is not expected to operate in the near 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. The plant is not expected to operate in the near future unless fractionation spreads are favorable, and volumes are sufficient to run the plant.

    - *Sabine Pass Processing Plant.* The Sabine Pass processing plant is located east of the Sabine River in Johnson's Bayou, Louisiana and has a processing capacity of 300 MMcf/d of natural gas. In 2013, we shut down the Sabine Pass processing plant and do not anticipate reopening the plant based on current market conditions.

  - *Belle Rose Gas Storage Facility.* The Belle Rose storage facility is located in Assumption Parish, Louisiana. This facility was placed in service in May 2016 and is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline.

  - *Sorrento Gas Storage Facility.* The Sorrento gas storage facility is located in Assumption Parish, Louisiana. This facility is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline.

- Louisiana Liquids Pipeline System. Our Louisiana liquids pipeline system includes NGL transport lines, fractionation assets, and underground NGL storage.

  - *Cajun-Sibon Pipeline System.* The Cajun-Sibon pipeline system transports unfractionated NGLs from areas such as the Liberty, Texas interconnects near Mont Belvieu, Texas, and, from time to time, our Gibson and Pelican processing plants in South Louisiana to either the Plaquemine or Eunice fractionators or to third-party fractionators when necessary.

  - *Ascension Pipeline.* The Ascension JV is an NGL pipeline that connects our Riverside fractionator to Marathon Petroleum Corporation’s Garyville refinery and is owned 50% by Marathon Petroleum Corporation.

  - *Fractionation Facilities.* There are four fractionation facilities located in Louisiana that are connected to our processing facilities and to Mont Belvieu, Texas and other hubs through our Cajun-Sibon pipeline system.

    - *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 produces purity ethane and propane for sale to markets via pipeline, while butane and heavier products are sent to our Riverside facility for further processing. The Plaquemine fractionator, collectively with the Riverside Fractionation Facility, has an approximate capacity of 117,000 Bbls/d of raw-make NGL products.

    - *Plaquemine Gas Processing Plant.* In addition to the Plaquemine fractionation facility, the adjacent Plaquemine gas processing plant also has an on-site fractionator.

    - *Eunice Fractionation Facility.* The Eunice fractionation facility is located in south central Louisiana. Liquids are delivered to the Eunice fractionation facility by the Cajun-Sibon pipeline system. The Eunice fractionation facility fractionates butane and heavier products from our Riverside facility and is directly connected to NGL markets and to a third-party storage facility.

    - *Riverside Fractionation Facility.* The Riverside fractionator and loading facility are located on the Mississippi River upriver from Geismar, Louisiana. Liquids are delivered to the Riverside fractionator by pipeline from the Eunice and Pelican processing plants or by third-party truck and rail assets. The loading/unloading facility has the capacity to transload 15,000 Bbls/d of crude oil and condensate from rail cars to barges.

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

Crude and Condensate. Our Crude and Condensate assets consist of crude oil and condensate pipelines, above ground storage, and a trucking fleet.

- *Ohio River Valley.* 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, crude oil and condensate pipelines in Ohio and West Virginia, above ground crude oil storage, a trucking fleet comprised of both semi and straight trucks, trailers for hauling NGL volumes, and seven existing brine disposal wells. Additionally, our ORV operations include eight condensate stabilization and natural gas compression stations that are supported by long-term, fee-based contracts with multiple producers.

- *Permian Crude and Condensate.* Our Permian Crude and Condensate assets have crude oil gathering, transportation, and marketing operations in the Permian Basin. These assets include:

  - *ECP System.* The ECP System includes trucking and crude gathering pipelines that were acquired in 2015.

  - *Avenger Crude Oil Gathering System.* During 2018, we constructed a new crude oil gathering system in the northern Delaware Basin called Avenger. Avenger is supported by a long-term contract with Devon on dedicated acreage in their Todd and Potato Basin development areas in Eddy and Lea counties in New Mexico. We commenced initial operations on Avenger during the third quarter of 2018 and expect to begin full-service operations during the third quarter of 2019.

  - *Greater Chickadee Gathering system.* Greater Chickadee was placed into service in March 2017 and delivers crude oil for customers to Enterprise Product Partners L.P.'s crude oil terminal in West Texas. Greater Chickadee also includes multiple central tank batteries with pump, truck injection, and storage stations to maximize shipping and delivery options for producers.

- *Central Oklahoma Crude Oil Gathering Systems.* Black Coyote was built primarily on acreage dedicated from Devon, which is the main shipper on the system. In addition, we further expanded our crude oil gathering operations in the STACK through the construction of Redbud, which is supported by a contract with Marathon Oil Company. We commenced initial operations on Redbud during the third quarter of 2018.

- *Victoria Express Pipeline.* VEX includes a multi-grade crude oil pipeline with terminals in Cuero and the Port of Victoria and barge docks. The Cuero truck unloading terminal at the origin of the VEX system contains eight unloading bays and above-ground storage capacity for receipt from, and delivery to, the VEX pipeline. The VEX pipeline terminates at the Port of Victoria Terminal, which has an eight-bay truck unloading dock and above-ground storage capacity. The Port of Victoria Terminal delivers to two barge loading docks at the Port of Victoria. We have an agreement with Devon to ship on VEX, which includes an MVC of 30,000 Bbls/d, that will remain in effect until July 2019.

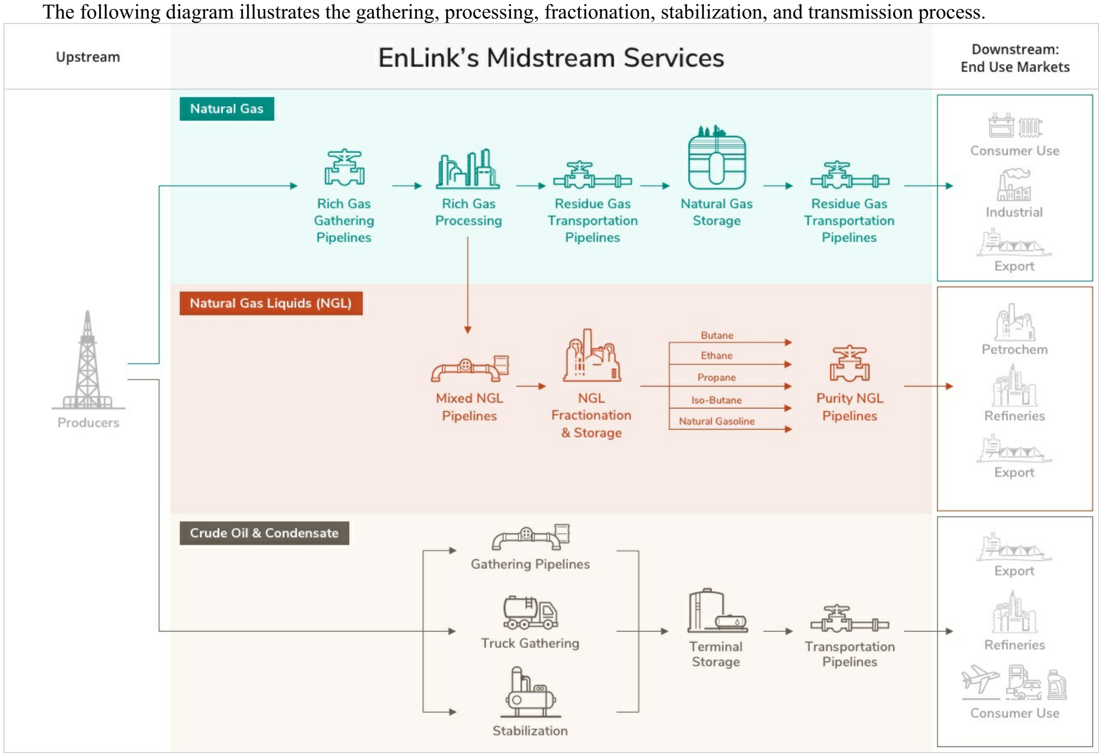
Corporate. Our Corporate assets primarily consist of our 38.75% ownership interest in GCF and 30% ownership interest in the Cedar Cove JV.

- *Gulf Coast Fractionators.* We own a 38.75% interest in GCF, with the remaining interests owned 22.5% by Phillips 66, and 38.75% by Targa Resources Partners, LP. GCF owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. GCF receives raw mix NGLs from customers, fractionates the raw mix, and redelivers the finished products to the customers for a fee.

- *Cedar Cove JV.* On November 9, 2016, we formed a joint venture with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma, which tie into our existing Oklahoma assets. All gas gathered by the Cedar Cove JV is processed by our Central Oklahoma processing facilities. We own 30% of the Cedar Cove JV.

Industry Overview

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



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

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

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

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

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

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

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

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

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

Storage. Demand for natural gas, NGLs, and crude oil fluctuate daily and seasonally, while production and pipeline deliveries are relatively constant in the short term. Storage of products during periods of low demand helps to ensure that sufficient supplies are available during periods of high demand. Natural gas and NGLs are stored in large volumes in underground facilities and in smaller volumes in tanks above and below ground, while crude oil is typically stored in tanks above ground.

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada. In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium market delivery points via pipelines, trucks, or rail.

Balancing Supply and Demand

When we purchase natural gas, NGLS, crude oil, and condensate, we establish a margin normally by selling it for physical delivery to third-party users. We can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the New York Mercantile Exchange ("NYMEX") related to our natural gas purchases. Through these transactions, we seek to maintain a position that is balanced between (1) purchases and (2) sales or future delivery obligations. Our policy is not to acquire and hold natural gas, NGL, or crude oil 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. For areas where acreage is not dedicated to us, we will compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation, which may offer more services or have strong financial resources and access to larger natural gas, NGLs, crude oil, and condensate supplies than we do. Our competition varies in different geographic areas.

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

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

Natural Gas, NGL, Crude Oil, and Condensate Supply

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

Credit Risk and Significant Customers

We are subject to risk of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. We diligently attempt to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of crude oil, condensate, NGLs, and natural gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to our overall profitability. A substantial portion of our throughput volumes come from customers that have investment-grade ratings. However, lower commodity prices in future periods may result in a reduction in our customers' liquidity and ability to make payments or perform on their obligations to us. Some of our customers have filed for bankruptcy protection, and their debts and payments to us are subject to laws governing bankruptcy.

The following customers individually represented greater than 10% of our consolidated revenues. These customers represent a significant percentage of revenues, and the loss of the customer would have a material adverse impact on our results of operations because the revenues and gross operating margin received from transactions with these customers is material to us. No other customers represented greater than 10% of our consolidated revenues.

	Year Ended December 31,		
	2018	2017	2016
Devon	10.4%	14.4%	18.5%
Dow Hydrocarbons and Resources LLC	11.1%	11.2%	10.8%
Marathon Petroleum Corporation	11.5%	(1)	(1)

(1) Consolidated revenues for Marathon Petroleum Corporation did not exceed 10% of our consolidated revenues for the years ended December 31, 2017 and 2016.

Regulation

Natural Gas Pipeline Regulation. We own interstate natural gas pipelines that are subject to regulation as natural gas companies by the FERC under the Natural Gas Act ("NGA"). FERC regulates the rates and terms and conditions of service on interstate natural gas pipelines, as well as the certification, construction, modification, expansion, and abandonment of facilities.

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

The cost-of-service rates charged by our FERC regulated natural gas pipelines may also be affected by FERC's income tax allowance policy, although we do not currently expect to experience any impact to financial results as a result of this policy. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *United Airlines, Inc., et al.v. FERC*, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting SFPP, L.P., then an interstate petroleum products pipeline organized as a master limited partnership, to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline double-recovering its investors' income taxes. The court vacated FERC's order and remanded to FERC. In March 2018, FERC issued an Order on Remand to SFPP, L.P. and simultaneously issued a revised policy statement disallowing master limited partnerships from recovering both an income tax allowance for the partners' tax costs and a discounted cash flow return on equity in their cost-of-service rates. The revised policy statement further provides that FERC will address the application of this policy to partnerships and pass-through entities that are not organized as master limited partnerships in subsequent proceedings on a case-by-case basis as the issue arises. In July 2018, FERC dismissed the requests for rehearing of the revised policy statement and provided guidance that if a pipeline organized as a master limited partnership or other pass-through entity eliminates its income tax allowance from its cost of service, FERC anticipates that such pipeline will also remove accumulated deferred income taxes from its cost of service. FERC further required all interstate natural gas pipelines to file a one-time informational filing in 2018 on a new form in order to collect information to evaluate the impact of the 2017 Tax Cuts and Jobs Act and the revised policy statement on such pipelines.

In addition to policies regarding rate setting, interstate natural gas pipelines regulated by FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates if such marketing affiliates are shippers on their interstate natural gas pipelines. FERC's market oversight and transparency regulations require regulated entities to submit annual reports of threshold purchases or sales of natural gas and publicly post certain information on scheduled volumes. FERC's market manipulation regulations, promulgated pursuant to the Energy Policy Act of 2005 (the "EPAct 2005"), make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme, or artifice to defraud; (2) make any untrue statement of material fact or omit to state a material fact necessary to make the statements made not misleading (in light of the circumstances under which the statements were made); or (3) engage in any act, practice, or course of business that operates (or would operate) as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to give FERC authority to impose civil penalties for violations of these statutes up to $1.0 million per day per violation for violations occurring after August 8, 2005. The maximum penalty authority established by the statute has been adjusted to approximately $1.3 million per day per violation and will continue to be adjusted periodically for inflation. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

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

In addition to Section 311 regulation, our intrastate natural gas pipeline operations are subject to regulation by various state agencies. Most state agencies possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment, and interconnection of physical facilities for intrastate pipelines. State agencies also may regulate transportation rates, service terms, and conditions and contract pricing.

Liquids Pipeline Regulation. We own certain liquids and crude oil pipelines that are regulated by FERC as common carrier interstate pipelines under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992, and related rules and orders.

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

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. This adjustment is subject to review every five years. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. On October 20, 2016, however, FERC issued an Advance Notice of Proposed Rulemaking indicating that FERC is considering a new policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service by a certain percentage or where the proposed index increases exceed certain annual cost changes reported to FERC. Under current FERC regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. The cost-of-service rates charged by our interstate liquids pipelines may also be affected by FERC's revised income tax allowance policy statement discussed above. In addition, FERC intends to incorporate its revised income tax allowance policy as well as the impact of the tax reduction from the Tax Cuts and Jobs Act of 2017 in its next five-year review of the oil pipeline index, which is scheduled to occur in 2020 to establish the index level for the July 1, 2021 to June 30, 2026 time period.

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 pay 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, including services that our marketing companies provide on our FERC-regulated liquids pipelines, 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 NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While such regulatory regimes vary, state agencies typically require intrastate NGL and petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish that a pipeline is a gathering pipeline and therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, however, so the classification and regulation of our gathering facilities are subject to change. Application of FERC jurisdiction to our gathering facilities could increase our operating costs, decrease our rates, and adversely affect our business. State regulation of gathering facilities generally includes various safety, environmental, and, in some circumstances, nondiscriminatory requirements and complaint-based rate regulation.

In addition, 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.

Natural Gas Storage Regulation. In December 2016, the DOT's Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued an interim final rule ("IFR") that addresses safety issues related to downhole facilities located at both intrastate and interstate underground storage facilities. The IFR incorporates by reference two of the American Petroleum Institute's Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Under the IFR, all intrastate transportation related underground natural gas storage facilities will become subject to minimum federal safety standards and be inspected by PHMSA or by a state entity that has chosen to expand its authority to regulate these facilities under a certification filed with PHMSA. The IFR became effective on January 18, 2017, with a compliance deadline of January 18, 2018. PHMSA subsequently determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the IFR that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule. On October 19, 2017, PHMSA formally reopened the comment period on the IFR in response to a petition for reconsideration. This matter remains ongoing and subject to future PHMSA determinations. We are in compliance with this IFR.

Certain of our field injection and withdrawal wells and water disposal wells are subject to the jurisdiction of the Railroad Commission of Texas ("TRRC"). TRRC regulations require that we report the volumes of natural gas and water disposal associated with the operations of such wells on a monthly and annual basis, respectively. Results of periodic mechanical integrity tests must also be reported to the TRRC. In addition, our underground gas storage caverns in Louisiana are subject to the jurisdiction of the Louisiana Department of Natural Resources ("LDNR"). In recent years, LDNR has put in place more comprehensive regulations governing underground hydrocarbon storage in salt caverns.

We also 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. For more information, see "Environmental Matters" below.

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, however, affected by the availability, terms, cost, and regulation of pipeline transportation.

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 PHMSA pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA") and the Pipeline Safety Improvement Act of 2002 ("PSIA"). The NGPSA regulates safety requirements in the design, construction, operation, and maintenance of gas pipeline facilities. The PSIA established mandatory inspections for all U.S. crude oil and natural gas transportation pipelines and some gathering lines in high-consequence areas ("HCAs"), which include, among other things, areas of high population density or that serve as sources of drinking water. PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. More recently, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly constructed pipelines, and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, and in June 2016, the President of the United States signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "PIPES Act"), which reauthorizes PHMSA's oil and gas pipeline programs through 2019.

In April 2016, PHMSA published a notice of proposed rulemaking ("NPRM"), addressing natural gas transmission and gathering lines. The proposed rule would, among other things, change existing integrity management requirements, expand assessment and repair requirements to pipelines in "moderate-consequence areas," including areas of medium population density, and increase requirements for monitoring and inspection of pipeline segments located outside of HCAs. Furthermore, this NPRM would require that records or other data relied on to determine operating pressures must be traceable, verifiable, and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in the reduction of allowable operating pressures, which would reduce available capacity on our pipelines. PHMSA, however, has yet to finalize this rulemaking, and the contents and timing of any final rule are currently uncertain.

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

On January 23, 2017, PHMSA published in the Federal Register amendments to the pipeline safety regulations to address requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and to update and clarify certain regulatory requirements regarding notifications of accidents and incidents. The final rule also adds provisions for cost recovery for design reviews of certain new projects, provides for renewal of existing special permits, and incorporates certain standards for in-line inspections and stress corrosion cracking assessments.

In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline.

At the state level, several states have passed legislation or promulgated rules 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 PHMSA or state requirements will not have a material adverse effect on our financial condition, results of operations, or cash flows.

On November 2, 2015, PHMSA issued a Notice of Probable Violation and Proposed Compliance Order (the “NOPV”) asserting probable violations of 49 CFR Part 195 due to our alleged misclassification of a transmission line as a gathering line. Transmission lines are subject to more fulsome pipeline safety regulations than gathering lines. The NOPV proposed a compliance order requiring us to satisfy the Part 195 requirements applicable to transmission lines but did not propose a penalty. On January 18, 2018, we received a letter from PHMSA withdrawing the NOPV and indicating that the case was closed effective as of January 18, 2018.

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

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals and permits, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in certain, less common circumstances, issuance of temporary or permanent injunctions, or construction or operation bans or delays. As part of the regular evaluation of 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 the environment, property, and persons as a result of any such upsets, releases, or spills. We may be unable to pass on current or future environmental costs to our customers. A discharge or release of hydrocarbons, hazardous substances, or solid wastes into the environment could, to the extent losses related to the event are not insured, subject 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, sediments, groundwater, and surface water and/or include measures to prevent and control pollution may pose significant costs to our industrial sector. These laws and regulations generally regulate the generation, storage, treatment, transportation, and disposal of solid wastes and hazardous substances and may require investigatory and corrective actions at facilities where such waste or substance may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the federal "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. Potentially responsible parties 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, state, or local 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 lose this exemption and be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Additionally, the Toxic Substances Control Act ("TSCA") and analogous state laws impose requirements on the use, storage, and disposal of various chemicals and chemical substances. In June 2017, the EPA finalized three rulemakings to update its implementation of TSCA. Two of the new rules establish the EPA's process and criteria for identifying high priority chemicals for risk evaluation and determining whether these high priority chemicals present an unreasonable risk to health or the environment. The third rule requires industry reporting of chemicals manufactured or processed in the U.S. over the past 10 years. 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 released on or under various properties owned, leased, or operated by us during the operating history of those properties. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices we had no control. These properties and wastes disposed thereon may be subject to the SWDA, 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 regulations promulgated thereunder and under comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various control, 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 or require us to incur additional capital expenditures. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition, results of operations, or cash flows, and the requirements are not expected to be more burdensome to us than to any similarly situated company.

In addition, the EPA included Wise County, the location of our Bridgeport facility, in its January 2012 revision to the Dallas-Fort Worth ozone nonattainment area (“DFW area”) for the 2008 revised ozone national ambient air quality standard (“NAAQS”). As a result of this moderate nonattainment designation, new major sources in Wise County, meaning sources that emit greater than 100 tons/year of nitrogen oxides (“NOx”) and volatile organic compounds (“VOCs”), as well as major modifications of existing facilities in the county resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review (“NSR”) pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at a 1.15 to 1 ratio. On November 14, 2018, EPA proposed to find that the DFW area failed to attain the 2008 ozone standard by its attainment date of July 20, 2017. If this proposal is finalized, the DFW area would be reclassified to a serious nonattainment area under this standard, imposing more stringent major source and major modification thresholds, increasing the applicable emission offset ratio, and potentially requiring the state to adopt more stringent permitting requirements.

In October 2015, the EPA promulgated a new NAAQS for ozone of 70 parts per billion (“ppb”) for both the 8-hour primary and secondary standards, down from the 75 ppb standards of the 2008 ozone NAAQS. On June 4, 2018, EPA designated the DFW area, including Wise County, as a marginal nonattainment area under this standard. EPA published a final rule to implement the 2015 ozone NAAQS on December 6, 2018. The area’s marginal classification does not require the additional control measures to be implemented. However, should the area fail to attain this standard by its marginal attainment date of August 2021, it risks reclassification to moderate, which could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in potentially significant expenditures for pollution control equipment. Furthermore, the area remains subject to the requirements associated with its serious classification under the 2008 standard notwithstanding its marginal classification under the 2015 standard. This new standard is being challenged in a pending appeal before the U.S. Court of Appeals for the D.C. Circuit, but if the standard is implemented, it could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in potentially significant expenditures for pollution control equipment.

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

In partial response to the issues raised regarding the 2012 rulemaking, the EPA recently finalized new rules that took effect August 2, 2016 to regulate emissions of methane and VOCs from new and modified sources in the oil and gas sector under the

NSPS. The EPA announced its intention to reconsider those regulations in April 2017 and sought to stay its requirements, however, the EPA's stay of these requirements was vacated by the D.C. Circuit in July 2017. In October 2018, and pursuant to its reconsideration, the EPA proposed a rule that would amend certain requirements of the NSPS standard. Accordingly, the rule remains in effect. In June 2016, the EPA also finalized a rule regarding alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities within one-quarter mile of one another to be deemed a major source on an aggregate basis, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. EPA draft guidance issued in September 2018 clarified that this rule pertains to the oil and gas industry. On November 10, 2016, the EPA issued a final Information Collection Request ("ICR") that requires numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, a step used to provide a basis for future rulemaking. The EPA withdrew this ICR in March 2017.

Other federal agencies have also taken steps to impose new or more stringent regulations on the oil and gas sector in order to further reduce methane emissions. For example, the BLM adopted new rules on November 15, 2016, to be effective on January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, the BLM published a final rule delaying the 2018 provisions until 2019. In February 2018, the BLM proposed to repeal certain of the requirements of the 2016 methane rules. Several states filed judicial challenges to the BLM's proposed repeal. However, this litigation was stayed in April 2018 pending the BLM's finalization or withdrawal of its February 2018 proposal. In September 2018, BLM published a final rule that largely adopted the February 2018 proposal and rescinded several requirements. The September 2018 rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. The challenge is still pending. As a result of this continued regulatory focus and other factors, additional GHG regulation of the oil and gas industry remains possible. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs for us and for other companies in our industry. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules, as well as any new state rules, may also make it more difficult for our suppliers and customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business. However, the status of recent and future rules and rulemaking initiatives under the Trump Administration remains uncertain.

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

In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. 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. In addition, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement entered into force November 4, 2016, and requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. In June 2017, the Trump Administration announced its intent to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the earliest date the United States can withdraw is November 2020. 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 condition, results of operations, or cash flows.

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. In June 2015, the EPA and the U.S. Army Corps of Engineers finalized a rule intended to clarify the meaning of the term "waters of the United States," ("WOTUS") which establishes the scope of regulated waters under the Clean Water Act. The rule has been challenged and was stayed by federal courts. If upheld, the rule is expected to expand federal jurisdiction under the Clean Water Act. On February 6, 2018, EPA and the U.S. Army Corps of Engineers published a final rule to postpone the effectiveness of the WOTUS rule until February 6, 2020. The February 2018 delay rule is subject to pending judicial challenges in multiple federal district courts. In December 2018, EPA and the Army Corps of Engineers issued a proposed rule that, if finalized, would narrow the scope of their jurisdiction. To the extent that any future rules expand the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for activities in jurisdictional waters, including wetlands. Regulations promulgated pursuant to the Clean Water Act require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") permits and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil, and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed by our permits and that continued compliance with such existing permit conditions will not have a material effect on our financial condition, results of operations, or cash flows.

We operate brine disposal wells that are regulated as Class II wells under the SDWA. The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting, and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the SDWA, such as the Ohio Department of Natural Resources rules that took effect October 1, 2012. These rules set new, more stringent standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state-of-the-art technology. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. Compliance with current and future laws and regulations regarding our brine disposal wells may impose substantial costs and restrictions on 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. In the state of Ohio, the Ohio Department of Natural Resources ("ODNR") requires a seismic study prior to the authorization of any new disposal well. In addition, the ODNR has instituted a continuous monitoring network of seismographs and is able to curtail injected volumes regionally based upon seismic activity detected. The Oklahoma Corporation Commission ("OCC") has also taken steps to focus on induced seismicity, including increasing the frequency of required recordkeeping for wells that dispose into certain formations and considering seismic information in permitting decisions. For instance, on August 3, 2015, the OCC adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes, the implementation of which has involved reductions of injection or shut-ins of disposal wells. The OCC also recently released well completion seismicity guidelines in December 2016 for operators in the STACK play that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. 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. Such regulations could also affect our customers' injection well operations and, therefore, impact our gathering business.

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 of our customers and suppliers. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities potentially can impact drinking water resources in the United States under some circumstances. This study or similar studies could spur initiatives to further regulate hydraulic fracturing. In June 2016, the EPA finalized rules prohibiting discharges of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Also, effective June 24, 2015, BLM adopted rules regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and American Indian lands. A federal district court invalidated these BLM rules in June 2016, but they were reinstated on appeal by the U.S. Court of Appeals for the Tenth Circuit in September 2017. In December 2017, BLM published a final rule rescinding the 2015 BLM rules. This rescission is subject to pending challenges in federal courts. Reinstatement of the 2015 BLM rules, or the adoption of 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 financial condition, results of operations or cash flows.

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

Office Facilities

We occupy approximately 157,600 square feet of space at our executive offices in Dallas, Texas under a lease expiring in February 2030. We also occupy office space of approximately 56,000 square feet in Midland, Texas, 32,000 square feet in Houston, Texas under long-term leases, and various other locations to support our operations.

Employees

As of December 31, 2018, we (through our subsidiaries) employed 1,449 full-time employees. Of these employees, 319 were general and administrative, engineering, accounting, and commercial personnel, and the remainder were operational employees. We are not party to any collective bargaining agreements, and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 1A. Risk Factors

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition, results of operations, or cash flows (including our ability to make distributions to our noteholders) could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.

We are dependent on Devon for a substantial portion of the natural gas that we gather, process, and transport. The expiration of five-year MVCs from Devon in 2019 and 2020 will result in a decline in our operating results and cash available for distribution because the volumes of natural gas that we gathered, processed, and transported for Devon during 2018 have been below the MVC levels under certain of our contracts.

We are dependent on Devon for a substantial portion of our natural gas supply. For the year ended December 31, 2018, Devon represented approximately 36.4% of our gross operating margin. In order to minimize volumetric exposure, in March 2014, we obtained five-year MVCs from Devon at the Bridgeport processing facility, Bridgeport, and East Johnson County gathering systems, and the Central Oklahoma gathering system, and these MVCs expired on January 1, 2019. We expect gross operating margin to decline approximately $90 million to $100 million due to the expiration of these MVCs. We also have a five-year MVC from Devon attributable to VEX, and this MVC expires on July 31, 2019. Because the volumes of natural gas and crude oil that we gather and transport on our systems are below the MVC levels, we will experience a decline in our operating revenues and cash flow. For the year ended December 31, 2018, we recognized $84.3 million, $1.2 million, and $11.5 million in MVC shortfall revenue from Devon attributable to our Texas, Oklahoma, and Crude and Condensate segments, respectively, because volumes were below the minimum level.

Because we are substantially dependent on Devon for a significant portion of our gross operating margin, any development that materially and adversely affects their operations, financial condition, or market reputation could have a material and adverse impact on us. Material adverse changes for Devon could restrict our access to capital, make it more expensive to access the capital markets, or increase the costs of our borrowings.

We expect to derive a significant portion of our gross operating margin from Devon for the foreseeable future. As a result, any development, whether in our area of operations or otherwise, that adversely affects their production, financial condition, leverage, market reputation, liquidity, results of operations, or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of our significant customers, some of which are the following:

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

Further, we are subject to the risk of non-payment or non-performance by Devon, including with respect to our gathering and processing agreements. We cannot predict the extent to which Devon's business will be impacted by pricing conditions in the energy industry, nor can we estimate the impact such conditions would have on Devon's ability to perform under our gathering and processing agreements. Additionally, due to our dependence on Devon, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Devon's financial condition or adverse changes in its credit ratings. S&P Global Ratings ("S&P") and Moody's Investors Services ("Moody's") have currently assigned to Devon a BBB and Ba1 credit rating, respectively. Any material limitations on our ability to access capital as a result of such adverse changes at Devon could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future limiting our ability to engage in, expand, or pursue our business activities and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas, and NGL services businesses would reduce our ability to make distributions to our unitholders.

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

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

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

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new crude oil, condensate, and natural gas reserves. In prior years we have seen suppressed drilling activity due to low commodity prices. Although drilling activity has improved during 2017 and 2018 in some of the most economic basins, including the Permian Basin, we could see downward pressure on future drilling activity in these basins if commodity prices decline below current levels, which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to our systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying our processing plants. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A continued decrease in the level of drilling activity or a material decrease in production in our principal geographic areas for a prolonged period, as a result of unfavorable commodity prices or otherwise, likely would have a material adverse effect on our financial condition, results of operations, and cash flows.

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

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

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

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

An impairment of goodwill, long-lived assets, including intangible assets and equity method investments, could reduce our earnings.

GAAP requires us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the unconsolidated affiliate investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. In the first quarter of 2016, we recognized a goodwill impairment of$566.3 million. For the year ended December 31, 2017, we recognized impairments on property and equipment of $17.1 million. For the year ended December 31, 2018, we recognized a goodwill impairment of $232.0 million and impairments on property and equipment of $133.8 million related to the carrying values of certain non-core natural gas and crude pipeline assets. Additional impairment of the value of our existing goodwill and long-lived assets could have a significant negative impact on our future operating results.

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

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

Construction of our major development projects subjects us to risks of construction delays, cost over-runs, limitations on our growth, and negative effects on our financial condition, results of operations, or cash flows.

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

Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations requires that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our business activities. A decision by a governmental authority or other third party to deny, delay, or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

In order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies, and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time needed to develop a site or pipeline alignment. Also, obtaining or renewing required permits or other approvals is sometimes delayed or prevented due to community opposition and other factors beyond our control. The denial of a permit or other approvals essential to our operations or the imposition of restrictive conditions with which it is not practicable or feasible to comply could impact our operations or prevent our ability to expand our operations or obtain rights-of-way. Significant opposition to a permit or other approvals by neighboring property owners, members of the public, or non-governmental organizations, or other third parties or delays in the environmental review and permitting process also could impact our operations or prevent our ability to expand our operations or obtain rights-of-way.

We conduct a portion of our operations through joint ventures, which subjects us to additional risks that could have a material adverse effect on the success of these operations, our financial position, results of operations, or cash flows.

We participate in several joint ventures, and we may enter into other joint venture arrangements in the future. The nature of a joint venture requires us to share control with unaffiliated third parties. If our joint venture partners do not fulfill their contractual and other obligations, the affected joint venture may be unable to operate according to its business plan, and we may be required to increase our level of commitment. If we do not timely meet our financial commitments or otherwise comply with our joint venture agreements, our ownership of and rights with respect to the applicable joint venture may be reduced or otherwise adversely affected. Differences in views among joint venture participants could also result in delays in business decisions or otherwise, failures to agree on major issues, operational inefficiencies and impasses, litigation, or other issues. Third parties may also seek to hold us liable for the joint ventures' liabilities. These issues or any other difficulties that cause a joint venture to deviate from its original business plan could have a material adverse effect on our financial condition, results of operations, or cash flows.

Any reductions in our credit ratings could increase our financing costs, increase the cost of maintaining certain contractual relationships, and reduce our cash available for distribution.

We cannot guarantee that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. S&P and Moody's have currently assigned to ENLK a BB+ and Ba1 credit rating, respectively, and to ENLC a BB+ and Ba1 credit rating, respectively. Any downgrade could also lead to higher borrowing costs for future borrowings and, if below investment grade, could require:

- additional or more restrictive covenants that impose operating and financial restrictions on us and our subsidiaries;
- our subsidiaries to guarantee such debt and certain other debt;
- us and our subsidiaries to provide collateral to secure such debt; and
- us or our subsidiaries to post cash collateral or letters of credit under our hedging arrangements or in order to purchase commodities or obtain trade credit.

Any increase in our financing costs or additional or more restrictive covenants resulting from a credit rating downgrade could adversely affect our ability to finance future operations. If a credit rating downgrade and the resultant collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations could be adversely affected.

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

We typically do not obtain independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate, and we are unable to secure additional sources, then the volumes transported on our gathering systems or that we otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on our financial condition, results of operations, or cash flows.

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

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

We have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points, and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect our margins or even result in losses. For example, we are a party to one contract associated with our North Texas operations with a term to June 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices 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. As of December 31, 2018, the balance sheet reflected a liability of $9.0 million related to this performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

Our profitability is dependent upon prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control and have been volatile. A depressed commodity price environment could result in financial losses and reduce our cash available for distribution.

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing and NGL fractionation components of our business. For the year ended December 31, 2018, approximately 9% of our total gross operating margin was generated under percent of liquids contracts and percent of proceeds contracts, with most of these contracts relating to our processing plants in the Permian Basin. Under percent of liquids contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Accordingly, our revenues under percent of liquids contracts are directly impacted by the market price of NGLs. Gross operating margin under percent of proceeds contracts is impacted only by the value of the natural gas or liquids produced with margins higher during periods of higher natural gas and liquids prices.

We also realize gross operating margins under processing margin contracts. For the year ended December 31, 2018, approximately 1% of our total gross operating margin was generated under processing margin contracts. We have a number of processing margin contracts for activities at our Plaquemine and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (“shrink”) and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction (“PTR”). Our margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices.

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

Although the majority of our NGL fractionation business is under fee-based arrangements, a portion of our business is exposed to commodity price risk because we realize a margin due to product upgrades associated with our Louisiana fractionation business. For the year ended December 31, 2018, gross operating margin realized associated with product upgrades represented approximately 1% of our gross operating margin.

The prices of crude oil, condensate, natural gas, and NGLs were volatile during 2018. Crude oil and weighted average NGL prices decreased 26% and 34%, respectively, while natural gas prices increased 19% from January 1, 2018 to December 31, 2018. We expect continued volatility in these commodity prices. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2018 ranged from a high of $76.41 per Bbl in October 2018 to a low of $42.53 per Bbl in December 2018. Weighted average NGL prices in 2018 (based on the Oil Price Information Service (“OPIS”) Napoleonville daily average spot liquids prices) ranged from a high of $0.93 per gallon in September 2018 to a low of $0.46 per gallon in December 2018. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2018 ranged from a high of $4.84 per MMBtu in November 2018 to a low of $2.55 per MMBtu in February 2018.

The markets and prices for crude oil, condensate, natural gas, and NGLs depend upon factors beyond our control that make it difficult to predict future commodity price movements with any certainty. These factors include the supply and demand for crude oil, condensate, natural gas, and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the supply and demand for crude oil and natural gas;
- the level of domestic crude oil, condensate, and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported crude oil, natural gas, and NGLs;
- international demand for crude oil and NGLs;
- actions taken by foreign crude oil and gas producing nations;
- the continued threat of terrorism and the impact of military action and civil unrest;
- the availability of local, intrastate, and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of hydraulic fracturing and “greenhouse gases.”

Changes in commodity prices also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil, and condensate we gather and process and NGLs we fractionate. Volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in “Item 7A. Quantitative and Qualitative Disclosure about Market Risk.” Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has (in the past) resulted and could (in the future) result in financial losses or reductions in our income.

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

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

We may not realize the benefits we expect from the Merger.

We believe that the Merger will, among other things, provide increased financial flexibility for execution of our strategic growth plan. However, our assessments and expectations regarding the anticipated benefits of the Merger may prove to be incorrect. Accordingly, there can be no assurance we will realize the anticipated benefits of the Merger.

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

We continue to have the ability to incur debt, subject to limitations in the Consolidated Credit Facility and the Term Loan, both of which we have guaranteed. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions, or other purposes may be impaired or such financing may not be available on favorable terms;
- our debt level will make us more vulnerable to general adverse economic and industry conditions;
- our ability to plan for, or react to, changes in our business and the industry in which we operate; and
- our risk that we may default on our debt obligations.

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

The terms of the Consolidated Credit Facility, Term Loan, and indentures governingour senior notes may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

The Consolidated Credit Facility and the Term Loan, both of which we have guaranteed, and the indentures governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur subsidiary indebtedness;
- engage in transactions with our affiliates;
- consolidate, merge, or sell substantially all of our assets;
- incur liens;
- enter into sale and lease back transactions; and
- change business activities we conduct.

In addition, the Consolidated Credit Facility and the Term Loan require ENLC to satisfy and maintain specified financial ratios. ENLC's ability to meet these financial ratios can be affected by events beyond its control, and we cannot assure you that ENLC will continue to meet these ratios.

Our ability to comply with the covenants and restrictions contained in the Consolidated Credit Facility, the Term Loan, and ENLK's indentures may be affected by events beyond our control, including prevailing economic, financial, and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A breach of any of these covenants could result in an event of default under the Consolidated Credit Facility, the Term Loan, and ENLK's indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable, and all applicable commitments to extend further credit could be terminated. If indebtedness under the Consolidated Credit Facility, the Term Loan, or ENLK's indentures is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

We are vulnerable to operational, regulatory, and other risks due to our significant assets in South Louisiana and the Texas Gulf Coast, including the effects of adverse weather conditions such as hurricanes.

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

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

- changes in the regulatory environment.

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

Our business is subject to a number of weather-related risks. These weather conditions can cause significant damage and disruption to our operations and adversely impact our financial condition, results of operations, or cash flows.

Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods, fires, severe temperatures, and earthquakes. In particular, South Louisiana and the Texas Gulf Coast experience hurricanes and other extreme weather conditions on a frequent basis. The location of our significant assets and concentration of activity in these regions make us particularly vulnerable to weather risks in these areas.

High winds, storm surge, flooding, and other natural disasters can cause significant damage and curtail our operations for extended periods during and after such weather conditions, which may result in decreased revenues and otherwise adversely impact our financial condition, results of operations, or cash flow. These interruptions could involve significant damage to people, property, or the environment, and repair time and costs could be extensive. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

In addition, we rely on the volumes of natural gas, crude oil, condensate, and NGLs gathered, processed, fractionated, and transported on our assets. These volumes are influenced by the production from the regions that supply our systems. Adverse weather conditions can cause direct or indirect disruptions to the operations of, and otherwise negatively affect, producers, suppliers, customers, and other third parties to which our assets are connected, even if our assets are not damaged. As a result, our financial condition, results of operations, and cash flows could be adversely affected.

We may also suffer reputational damage as a result of a natural disaster or other similar event. The occurrence of such an event, or a series of such events, especially if one or more of them occurs in a highly populated or sensitive area, could negatively impact public perception of our operations and/or make it more difficult for us to obtain the approvals, permits, licenses, rights-of-way, or real property interests we need in order to operate our assets or complete planned growth projects.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We could experience increased severity or frequency of trucking accidents and other claims, which could materially affect our results of operations.

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

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

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

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

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

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

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

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

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

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including the price of, and demand for, crude oil, condensate, NGLs, and natural gas in the markets we serve and competition from other midstream service providers. Our competitors include companies larger than we are, which could have both a lower cost of capital and a greater geographic coverage, as well as companies smaller than we are, which could have lower total cost structures. In addition, competition is increasing in some markets that have been overbuilt, resulting in an excess of midstream energy infrastructure capacity, or where new market entrants are willing to provide services at a discount in order to establish relationships and gain a foothold. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. As a consequence of the increase in competition in the industry and volatility of natural gas prices, industrial end-users and utilities may be reluctant to enter into long-term purchase contracts. Many industrial end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these industrial end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in marketing natural gas, we often compete in the industrial end-user and utilities markets primarily on the basis of price.

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

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders. Additionally, equity values for many of our customers continue to be low. The combination of a reduction in cash flow from lower commodity prices, a reduction in borrowing bases under reserve-based credit facilities, and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

Increased federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing could result in increased costs and reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. State legislatures and agencies have enacted legislation and promulgated rules to regulate hydraulic fracturing, require disclosure of hydraulic fracturing chemicals, temporarily or permanently ban hydraulic fracturing and impose additional permit requirements and operational restrictions in certain jurisdictions or in environmentally sensitive areas. EPA and the BLM have also issued rules, conducted studies, and made proposals that, if implemented, could either restrict the practice of hydraulic fracturing or subject the process to further regulation. For instance, the EPA has issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and adopted rules prohibiting the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA announced its intention to reconsider the regulations relating to the capture of air emissions in April 2017 and sought to stay its requirements, however, EPA's stay of these requirements was vacated by the D.C. Circuit in July 2017. In October 2018, and pursuant to its reconsideration, EPA proposed a rule that would amend certain requirements of the NSPS standard. Accordingly, the rule remains in effect along with the restriction on discharges to publicly owned wastewater treatment plants. The BLM also adopted new rules, effective on January 17, 2017, to reduce venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, BLM published a final rule delaying the 2018 provisions until 2019. In February 2018, the BLM proposed to repeal certain of the requirements of the 2016 methane rules. Several states filed judicial challenges to the BLM's proposed repeal. However, this litigation was stayed in April 2018 pending the BLM's finalization or withdrawal of its February 2018 proposal. In September 2018, BLM published a final rule that largely adopted the February 2018 proposal and rescinded several requirements. The September 2018 rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. The challenge is still pending. State and federal regulatory agencies also have recently focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in induced seismicity, which has resulted in some regulation at the state level. For instance, in December 2016 the Oklahoma Corporation Commission released well completion seismicity guidelines for operators in the STACK play that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. As regulatory agencies continue to study induced seismicity, additional legislative and regulatory initiatives could affect our brine disposal operations and our customers' injection well operations, which could impact our gathering business.

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

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

The rates, terms, and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to regulation by FERC under the NGA and Section 311 of the NGPA and the rules and regulations promulgated under those statutes. Under the NGA, FERC regulation requires that interstate natural gas pipeline rates be filed with FERC and that these rates be “just and reasonable,” not unduly preferential and not unduly discriminatory, although negotiated or settlement rates may be accepted in certain circumstances. Interested persons may challenge proposed new or changed rates, and FERC is authorized to suspend the effectiveness of such rates pending an investigation or hearing. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a pipeline to change its rates prospectively. Accordingly, action by FERC could adversely affect our ability to establish rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition, results of operations, and cash available for distribution. Under the NGPA, we are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. In addition, our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for transportation service should be lowered, our business could be adversely affected.

The cost-of-service rates charged by our FERC-regulated natural gas pipelines may also be affected by FERC’s income tax allowance policy, although we do not currently expect to experience any impact to financial results as a result of this policy. This policy disallows master limited partnerships from recovering both an income tax allowance for the partners’ tax costs and a discounted cash flow return on equity in their cost-of-service rates and provides that FERC will address this double recovery as it relates to partnerships and pass-through entities not organized as master limited partnerships in subsequent proceedings on a case-by-case basis as the issue arises.

Additionally, FERC required all interstate natural gas pipelines to file a one-time informational filing in 2018 on a new form in order to collect information to evaluate the impact of the Tax Cuts and Jobs Act of 2017, which included a reduction in the highest marginal U.S. federal corporate income tax rate from 35% to 21%, effective for taxable years beginning on or after January 1, 2018. At this time, it is uncertain how the cost of service rates of our interstate natural gas pipelines could be affected by this one-time filing to the extent FERC proposes new rates or challenges or changes to our existing rates as a result of such filing.

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

If we fail to comply with all the applicable FERC-administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority to impose penalties for current violations of the NGA or NGPA of up to $1.0 million per day for each violation. The maximum penalty authority established by statute has been adjusted to approximately $1.3 million per day and will continue to be adjusted periodically for inflation. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

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

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

Our interstate liquids transportation pipelines are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. If, upon completion of an investigation, FERC finds that new or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively if it determines that the rates are unjust and unreasonable or unduly discriminatory or preferential. Under certain circumstances, FERC could limit our recovery of costs or could require us to reduce our rates and the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. In particular, FERC's current income tax allowance policy could affect our rates going forward, although we do not currently expect to experience any impact to financial results as a result of this policy. In addition, our rates going forward could be affected by proposed changes to FERC's annual indexing methodology, including both changes to the methodology to account for the impact of the tax reduction from the Tax Cuts and Jobs Act of 2017 as well as the potential adoption of a policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service numbers by a certain percentage or where the proposed index increases exceed certain annual cost changes. All of these FERC policies and potential changes could have a material impact on our business and, if accepted, could decrease our rates and adversely affect our business.

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

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

The pipelines we own and operate are subject to stringent and complex regulation related to pipeline safety and integrity management. For instance, the Department of Transportation, through PHMSA, has established a series of rules that require pipeline operators to develop and implement integrity management programs for hazardous liquid (including oil) pipeline segments that, in the event of a leak or rupture, could affect HCAs. In April 2016, PHMSA also proposed rules that would expand existing integrity management requirements to natural gas transmission and gathering lines in areas with medium population densities. PHMSA, however, has yet to finalize this rulemaking, and the contents and timing of any final rule are currently uncertain. Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies, such as the TRRC, could result in substantial expenditures for testing, repairs, and replacement. For example, TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $1.8 million, $2.3 million, and $3.3 million for the years ended December 31, 2018, 2017, and 2016, respectively. If our pipelines fail to meet the safety standards mandated by the TRRC or PHMSA regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced operating pressure, the cost of which actions cannot be estimated at this time.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. Moreover, because certain of our operations are located around urban or more populated areas, such as the Barnett Shale, we may incur additional expenses from compliance with municipal and other local or state regulations that impose various obligations including, among other things, regulating the locations of our facilities; limiting the noise, odor, or light levels of our facilities; and requiring certain other improvements, including to the appearance of our facilities, that result in increased costs for our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation activities.

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

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

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

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

We are subject to stringent and complex regulation under the federal Clean Air Act, implementing regulations, and state and local equivalents, including regulations related to controls for oil and natural gas production, pipelines, and processing operations. For instance, the EPA finalized new rules, effective August 2, 2016, to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector. The EPA announced its intention to reconsider those regulations in April 2017 and has sought to stay its requirements. In October 2018, and pursuant to its reconsideration, EPA proposed a rule that would amend certain requirements of the NSPS standard. However, EPA's stay of these requirements was vacated by the D.C. Circuit in July 2017. Accordingly, the rule remains in effect. The EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source if within one quarter-mile of one another, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. In addition, on November 10, 2016, the EPA issued a final Information Collection Request ("ICR") that requires numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, a step used to provide a basis for future rulemaking. The EPA withdrew this ICR in March of 2017.

The BLM also adopted new rules on November 15, 2016, effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, BLM published a final rule delaying the 2018 provisions until 2019. In February 2018, the BLM proposed to repeal certain of the requirements of the 2016 methane rules. Several states filed judicial challenges to the BLM's proposed repeal. However, this litigation was stayed in April 2018 pending the BLM's finalization or withdrawal of its February 2018 proposal. In September 2018, BLM published a final rule that largely adopted the February 2018 proposal and rescinded several requirements. The September 2018 rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. The challenge is still pending.

Additional regulation of GHG emissions from the oil and gas industry remains a possibility. These regulations could require a number of modifications to our operations, and our natural gas exploration and production suppliers' and customers' operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for our services. Responding to rule challenges, the EPA has since revised certain aspects of its April 2012 rules and has indicated that it may reconsider other aspects of the rules.

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

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the adoption of the Paris Agreement. The Paris Agreement became effective November 4, 2016 and requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. Although the Trump Administration has announced its intent to withdraw from the Paris Agreement, the earliest effective date of this withdrawal pursuant to the terms of the Paris Agreement is November 2020. At the federal regulatory level, both the EPA and the BLM have adopted regulations for the control of methane emissions, which also include leak detection and repair requirements, from the oil and gas industry.

In addition, many states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved.

Although it is not possible at this time to predict whether future legislation or new regulations may be adopted to address greenhouse gas emissions or how such measures would impact our business, the adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our performance of operations in the absence of any permits that may be required to regulate emission of GHGs, or could adversely affect demand for the natural gas we gather, process, or otherwise handle in connection with our services.

The ESA and MBTA govern our operations and additional restrictions may be imposed in the future, which could have an adverse impact on our operations.

The ESA and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the MBTA. The U.S. Fish and Wildlife Service and state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species, which could materially restrict use of or access to federal, state, and private lands. Some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. In addition, the U.S. Fish and Wildlife Service and state agencies regularly review species that are listing candidates, and designations of additional endangered or threatened species, or critical or suitable habitat, under the ESA could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. The occurrence of a significant accident or other event that is not fully insured could adversely affect our operations and financial condition.

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

- damage to pipelines, facilities, storage caverns, equipment, and surrounding properties caused by hurricanes, floods, sink holes, fires, and other natural disasters and acts of terrorism;
- inadvertent damage to our assets from construction or farm equipment;
- leaks of natural gas, NGLs, crude oil, condensate, and other hydrocarbons;
- induced seismicity;

- rail accidents, barge accidents, and truck accidents;
- equipment failure; and
- fires and explosions.

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

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

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several relevant regulations, and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not, and, as a result, the final form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC proposed and revised new rules in November 2013 and December 2016, respectively, that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC sought comment on the position limits rules as reproposed and revised, but the new rules have not yet been issued in final form, and the impact of any final provisions on us is uncertain at this time.

The legislation and potential new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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

Our operations expose us to fluctuations in commodity prices, and the Consolidated Credit Facility and the Term Loan expose us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. As of December 31, 2018, we have hedged only portions of our expected exposures to commodity price risk. In addition, to the extent we hedge our commodity price risk using swap instruments, we will forego the benefits of favorable changes in commodity prices.

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

- hedging can be expensive, particularly during periods of volatile prices;
- our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and

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

A failure in our computer systems or a terrorist or cyberattack on us, or third parties with whom we have a relationship, may adversely affect our ability to operate our business.

We are reliant on technology to conduct our business. Our business is dependent upon our operational and financial computer systems to process the data necessary to conduct almost all aspects of our business, including operating our pipelines, plants, truck fleet, and other facilities, recording and reporting commercial and financial transactions, and receiving and making payments. Any failure of our computer systems, or those of our customers, suppliers, or others with whom we do business, could materially disrupt our ability to operate our business. Unknown entities or groups have mounted so-called “cyberattacks” on businesses to disable or disrupt computer systems, disrupt operations, and steal funds or data including through so-called “phishing” schemes. Cyberattacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt our operations and critical business functions. In addition, our assets may be targets of terrorist activities that could disrupt our ability to conduct our business and have a material adverse effect on our business and results of operations. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyberattacks than other targets in the United States. Our insurance may not protect us against such occurrences. Any such terrorist or cyberattack that affects us or our customers, suppliers, or others with whom we do business could have a material adverse effect on our business, cause us to incur a material financial loss, subject us to possible legal claims and liability, and/or damage our reputation.

Moreover, as cyberattacks continue to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities. In addition, cyberattacks against us or others in our industry could result in additional regulations, which could lead to increased regulatory compliance costs, insurance coverage cost, or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

Our business is subject to complex and evolving U.S. laws and regulations regarding privacy and data protection (“data protection laws”). Many of these laws and regulations are subject to change and uncertain interpretation, and could result in claims, increased cost of operations, or otherwise harm our business.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New data protection laws pose increasingly complex compliance challenges and potentially elevate our costs. Complying with varying jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws can result in significant penalties. Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments, and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of cyberattacks, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

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

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

Failure to attract and retain an appropriately qualified workforce could reduce labor productivity and increase labor costs, which could have a material adverse effect on our business and results of operations.

Gathering and compression services require laborers skilled in multiple disciplines, such as equipment operators, mechanics, and engineers, among others. Our business is dependent on our ability to recruit, retain, and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor, or the unavailability of contract resources, may lead to operating challenges such as a lack of resources, loss of knowledge, or a lengthy time period associated with skill development. Our costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

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

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

Our assets were constructed over many decades using varying construction and coating techniques, which may cause our inspection, maintenance, or repair costs to increase in the future. In addition, there could be service interruptions due to unknown events or conditions or increased downtime associated with our pipelines that could have a material adverse effect on our financial condition, results of operations, or cash flows.

Our pipelines were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied over time and can vary for individual pipelines. Depending on the construction era and quality, some assets will require more frequent inspections or repairs, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our financial condition, results of operations, or cash flows.

Risks Inherent in an Investment in the Partnership

GIP, through its control of ENLC, controls our general partner, which has sole responsibility for conducting our business and managing our operations. GIP may have conflicts of interest with us, has limited duties to us, and may favor GIP's interests to the detriment of, our unitholders.

GIP, through its control of ENLC, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Conflicts of interest may arise in the future among GIP and its affiliates, including our general partner, on the one hand, and our partnership and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and those of its affiliates, including GIP and ENLC, over our interests. Subject to certain limitations, our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner.

GIP is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

GIP is a private equity firm with significant resources and experience making investments in midstream energy businesses. GIP is not prohibited from owning assets or interests in entities, or engaging in businesses, that compete directly or indirectly with us. Affiliates of GIP currently own interests in other oil and gas companies, including midstream companies, which may compete directly or indirectly with us. In addition, GIP and its affiliates may acquire, construct, or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner, its executive officers, or any of its affiliates, including GIP. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity, or does not communicate such opportunity or information to us. As a result, competition from GIP, its affiliates, and other companies in which it owns interests could materially and adversely impact our results of operations and distributable cash flow. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

GIP has pledged all of the equity interests that it owns in ENLC and ENLC's managing member to GIP's lenders under its credit facility. A default under GIP's credit facility could result in a change of control of our general partner.

GIP has pledged all of the equity interests that it owns in ENLC and ENLC's managing member to its lenders as security under GIP's senior secured credit facility. Although we are not a party to this credit facility, if a default under such credit facility were to occur, the lenders could foreclose on the pledged equity interests. Any such foreclosure on GIP's interest would result in a change of control of our general partner and would allow the new owner of our general partner to replace the board of directors and officers of our general partner with its own designees and to control the decisions taken by the board of directors and officers. Moreover, any change of control of our general partner would permit the lenders under the Consolidated Credit Facility and the Term Loan to declare all amounts thereunder immediately due and payable, and if any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

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

Unitholders' voting rights are restricted by the partnership agreement, which provides that, other than Enfield with respect to the Series B Preferred Units, any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter.

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

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

Our partnership agreement replaces the fiduciary duties otherwise owed to our unitholders by our general partner with contractual standards governing its duties and restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

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

- how to allocate business opportunities among us and its other affiliates;
- whether or not to consent to any merger or consolidation of us or any amendment to our partnership agreement; and
- whether or not the general partner should elect to seek the approval of the unitholders in connection with any conflicted transaction.

The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties.

We may issue additional units, including units that are pari passu with our Series C Preferred Units, without the approval of the holders of the Series C Preferred Units.

We may issue an unlimited number of limited partner interests in parity with the Series C Preferred Units without any vote of the holders of the Series C Preferred Units (except where the cumulative distributions on the Series C Preferred Units or any parity securities are in arrears and in certain other circumstances).

Additionally, although holders of the Series C Preferred Units are entitled to limited voting rights, with respect to certain matters the Series C Preferred Units generally vote separately as a class along with all other series of our parity securities that we may issue with respect to which like voting rights have been conferred and are exercisable. As a result, the voting rights of holders of Series C Preferred Units may be significantly diluted, and the holders of such other series of parity securities that we may issue may be able to control or significantly influence the outcome of any vote. The issuance of additional units on parity with or senior to the Series C Preferred Units would dilute the interests of the holders of the Series C Preferred Units, and any issuance of equity securities of any class or series that ranks on parity with the Series C Preferred Units as to the payment of distributions and amounts payable upon a liquidation event or additional indebtedness could affect our ability to pay distributions on, redeem, or pay the liquidation preference on the Series C Preferred Units.

Future issuances and sales of parity securities, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series C Preferred Units to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Our outstanding equity and debt securities are not listed on the NYSE or any other national securities exchange and, as a result, we are not obligated to comply with any exchange listing requirements.

Our outstanding equity and debt securities are not listed on the NYSE or any other national securities exchange, which means that we are exempt from any exchange listing requirements.

For so long as we do not have securities listed on a national securities exchange, we will not be required to have a majority of independent directors, an independent audit committee, or nominating, corporate governance, or compensation committees. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to the corporate governance requirements of a national securities exchange.

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

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the “control” of our business, to the extent that a person who has transacted business with the Partnership reasonably believes, based on our unitholders’ conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of our partnership, such as its debts and environmental liabilities, except for those contractual obligations of our partnership that are expressly made without recourse to our general partner. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Revised Uniform Limited Partnership Act (“the Delaware Act”), a limited partnership cannot make a distribution to its limited partners if, after the distribution, all liabilities, other than liabilities to unitholders on account of their limited partner interests and liabilities for which the recourse of creditors is limited to specific property of the limited partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the non-recourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act will be liable to the limited partnership for the amount of the distribution for three years from the date of distribution.

Tax Risks to Our Unitholders

Our tax treatment and our being subject to entity level taxation by individual states depends on our status as a partnership for federal income tax purposes. If the IRS treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution.

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

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 21% for taxable years beginning on or after January 1, 2018 (under the law as of the date of this report), and 35% to the extent we were treated as a corporation in any taxable years ending prior to January 1, 2018, and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in our anticipated cash flow.

Moreover, changes in current state law may subject us to entity-level taxation by individual states. Because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.75% of our taxable margin apportioned to Texas in the prior year. If additional state tax were to be imposed on us, the cash available for distribution could be reduced.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution might be substantially reduced.

If the IRS makes audit adjustments to income tax returns for tax years beginning after 2018, it may assess and collect taxes (including any applicable penalties and interest) directly from us, unless we are eligible to (and choose to) elect to push out those audit adjustments to those persons who were our unitholders during the tax period subject to such audit adjustments. If we make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution might be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during that taxable year.

Treatment of distributions on our Series C Preferred Units as guaranteed payments for the use of capital is uncertain.

The tax treatment of distributions on our Series C Preferred Units is uncertain. We will treat the holders of Series C Preferred Units as partners for tax purposes and will treat distributions on the Series C Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Series C Preferred Units as ordinary income. Although a holder of Series C Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions semi-annually on the 15th day of June and December through and including December 15, 2022 and, thereafter, quarterly on the 15th day of March, June, September and December of each year. Because the guaranteed payment for each unit must accrue as income to a holder during the taxable year of the accrual, the guaranteed payment attributable to the period beginning December 15 and ending December 31 will accrue as income to the holder of record of a Series C Preferred Unit on December 31 for such period, regardless of whether such holder continues to own the Series C Preferred Unit at the time the actual distribution is made. Otherwise, the holders of Series C Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction, nor will we allocate any share of our nonrecourse liabilities to the holders of Series C Preferred Units. If the Series C Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of Series C Preferred Units.

Tax-exempt entities and non-U.S. persons face unique issues from owning our Series C Preferred Units which may result in adverse tax consequences to them.

Investment in the Series C Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts (“IRAs”), and non-U.S. persons raises issues unique to them. Although the issue is not free from doubt, we will treat distributions to non-U.S. holders of Series C Preferred Units as “effectively connected income” subject to withholding taxes. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders of Series C Preferred Units may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor with respect to the consequences of owning our Series C Preferred Units.

The tax treatment of an investment in our Series C Preferred Units could be subject to potential legislative, judicial, or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of an investment in our Series C Preferred Units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the requirements that must be satisfied in order for us to be treated as a partnership for federal income tax purposes.

We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our Series C Preferred Units.

Entity level taxes on income from our C corporation subsidiary will reduce cash available for distribution.

A portion of our taxable income is earned through a C corporation subsidiary. Such C corporation subsidiary is subject to federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 21%, and will likely pay state (and possibly local) income tax at varying rates, on its taxable income. Any such entity level taxes will reduce our cash available for distribution

Holders of Series C Preferred Units may be subject to state and local taxes and return filing or withholding requirements in jurisdictions where they do not live.

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

A unitholder whose Series C Preferred Units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units.

A holder of Series C Preferred Units whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units and, thus, may recognize gain or loss from such disposition. Our counsel has not rendered an opinion regarding the treatment of a unitholder where Series C Preferred Units are loaned to a short seller to cover a short sale of Series C Preferred Units; therefore, unitholders desiring to avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

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

Item 1B. Unresolved Staff Comments

We do not have any unresolved staff comments.

Item 2. Properties

A description of our properties is contained in "Item 1. Business."

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties, and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee. Our processing plants are located on land that we lease or own in fee.

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

Item 3. Legal Proceedings

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

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

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

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, resulting in damage to certain of our facilities. In order to recover our losses from responsible parties, we sued the operator of a failed cavern in the area, and its insurers, as well as other parties we alleged to have contributed to the formation of the sinkhole seeking recovery for these losses. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, and we subsequently reached settlements regarding the entirety of our claims in both lawsuits. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. We secured additional settlement payments during 2017, which resulted in the recognition of "Gain on litigation settlement" of$26.0 million on the consolidated statement of operations for the year ended December 31, 2017.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters, and Issuer Purchases of Equity Securities

Prior to the closing of the Merger, our common units were listed on the NYSE under the symbol "ENLK." Subsequent to the closing of the Merger, ENLC owns 100% of ENLK's common units. For equity compensation plan information, see the discussion under "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information."

We will distribute all of our available cash, as defined in our partnership agreement, to ENLC, as the holder of all of our common units. Our available cash consists generally of all cash on hand at the end of any fiscal quarter or other applicable period plus all cash on hand on the date of determination resulting from working capital borrowings made after the end of such applicable period, less reserves that our general partner determines are necessary to:

- provide for the proper conduct of our business;
- comply with applicable law, our debt instruments, or other agreements; and
- provide funds for distributions to the holders of the Series B Preferred Units and the Series C Preferred Units.

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Prior to the closing of the Merger, our distributions were made to our general partner based on its ownership interest with the remaining interest to unitholders, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders were achieved. Incentive distributions to our general partner increased to 13.0%, 23.0%, and 48.0% based on incremental distribution thresholds as set forth in our partnership agreement. Subsequent to the closing of the Merger, no incentive distributions are paid to our general partner.

Unregistered Sales of Equity Securities and Use of Proceeds

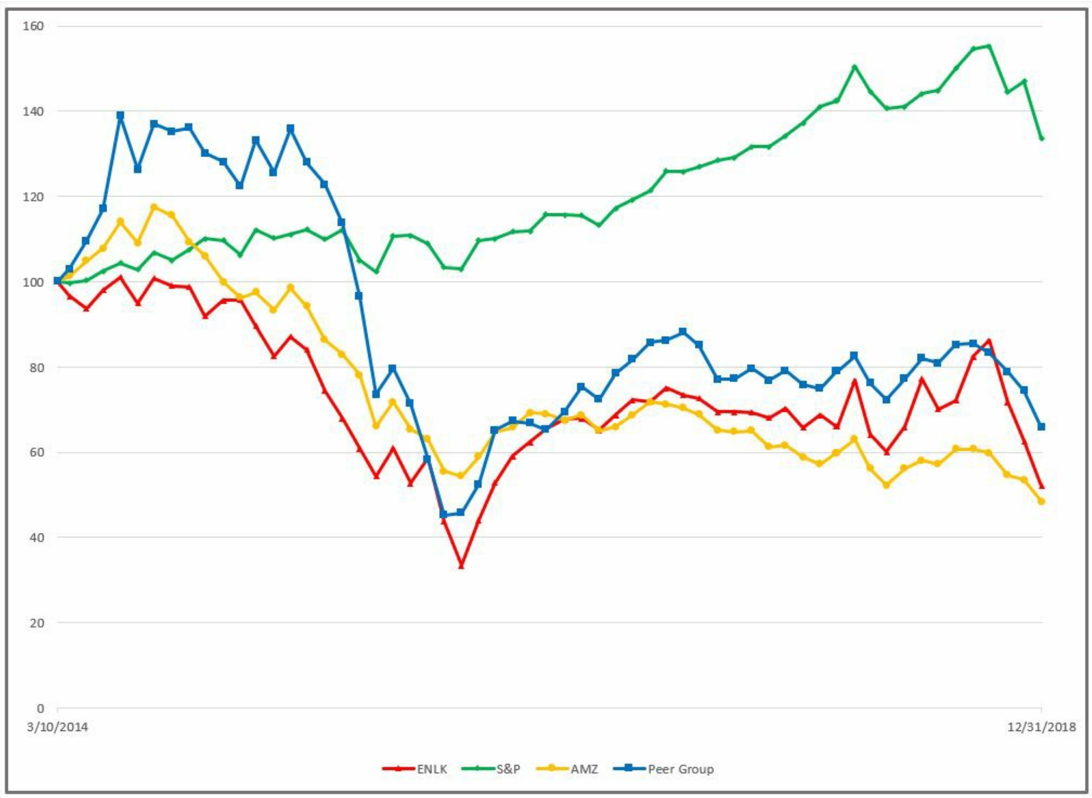
During the year ended December 31, 2018, we re-acquired ENLK common units from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted incentive units.

Period	Total Number of Units Purchased (1)	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Units that May Yet Be Purchased under the Plans or Programs
January 1, 2018 to January 31, 2018	153,512	$ 15.86	—	—
February 1, 2018 to February 28, 2018	1,034	17.48	—	—
March 1, 2018 to March 31, 2018	61,482	14.80	—	—
April 1, 2018 to April 30, 2018	4,449	13.64	—	—
May 1, 2018 to May 31, 2018	69	15.01	—	—
June 1, 2018 to June 30, 2018	3,107	17.14	—	—
July 1, 2018 to July 31, 2018	79,700	14.95	—	—
August 1, 2018 to August 31, 2018	61,808	17.15	—	—
September 1, 2018 to September 30, 2018	2,593	18.67	—	—
October 1, 2018 to October 31, 2018	194	18.64	—	—
November 1, 2018 to November 30, 2018	1,442	13.73	—	—
December 1, 2018 to December 31, 2018	3,774	12.65	—	—
Total	373,164	$ 15.67	—	—

(1) The common units were not re-acquired pursuant to any repurchase plan or program.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common units, the Standard & Poor's 500 Stock Index,Alerian MLP Index, and a peer group of publicly traded limited partnerships in the midstream natural gas, natural gas liquids, propane, and pipeline industries for the period from March 10, 2014 to the year ended December 31, 2018. The chart assumes that $100 was invested on March 10, 2014, with distributions reinvested. The peer group includes MPLX LP, Energy Transfer LP, Targa Resources, Corp., and Western Gas Equity Partners, LP.



Item 6. Selected Financial Data

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities, and operations of EnLink Midstream Holdings, LP, the predecessor to Midstream Holdings (the "Predecessor"), which is the historical predecessor of ENLK and (2) for periods on or after March 7, 2014, the results of operations of ENLK after giving effect to the Business Combination discussed under "Item 1. Business—General." The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon prior to the Business Combination, including its 38.75% interest in GCF. However, in connection with the Business Combination, only the Predecessor's systems serving the Barnett, Cana-Woodford, and Arkoma-Woodford Shales in Texas and Oklahoma, as well as a 38.75% interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

The following table presents our selected historical financial and operating data for the periods indicated. Financial and operating data for the years ended December 31, 2018, 2017, 2016, 2015, and 2014 reflect acquisitions and dispositions for periods subsequent to the applicable transaction date. The selected historical financial data should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and accompanying notes in "Item 8. Financial Statements and Supplementary Data."

	EnLink Midstream Partners, LP				
	Year Ended December 31,				
	2018	2017	2016	2015	2014 (1)
	(In millions, except per unit data)				
Revenues:					
Product sales	$ 6,512.3	$ 4,358.4	$ 3,008.9	$ 3,253.7	$ 2,159.3
Product sales—related parties	41.0	144.9	134.3	119.4	505.6
Midstream services	763.3	552.3	467.2	451.0	253.4
Midstream services—related parties	377.2	688.2	653.1	618.6	567.4
Gain (loss) on derivative activity	5.2	(4.2)	(11.1)	9.4	22.1
Total revenues	7,699.0	5,739.6	4,252.4	4,452.1	3,507.8
Operating costs and expenses:					
Cost of sales (2)	6,008.0	4,361.5	3,015.5	3,245.3	2,494.5
Operating expenses (3)	453.4	418.7	398.5	419.9	283.6
General and administrative (4)	130.2	123.5	119.3	132.4	94.5
(Gain) loss on disposition of assets	0.4	—	13.2	1.2	(0.1)
Depreciation and amortization	577.3	545.3	503.9	387.3	284.3
Impairments	365.8	17.1	566.3	1,563.4	—
Gain on litigation settlement	—	(26.0)	—	—	(6.1)
Total operating costs and expenses	7,535.1	5,440.1	4,616.7	5,749.5	3,150.7
Operating income (loss)	163.9	299.5	(364.3)	(1,297.4)	357.1
Other income (expense):					
Interest expense, net of interest income	(178.3)	(187.9)	(188.1)	(102.5)	(47.4)
Gain on extinguishment of debt	—	9.0	—	—	3.2
Income (loss) from unconsolidated affiliates	13.3	9.6	(19.9)	20.4	18.9
Other income (expense)	0.6	0.6	0.3	0.8	(0.5)
Total other expense	(164.4)	(168.7)	(207.7)	(81.3)	(25.8)
Income (loss) from continuing operations before non-controlling interest and income taxes	(0.5)	130.8	(572.0)	(1,378.7)	331.3
Income tax (provision) benefit	2.1	24.0	(1.3)	0.5	(22.0)
Net income (loss) from continuing operations	1.6	154.8	(573.3)	(1,378.2)	309.3
Discontinued operations:					
Income from discontinued operations, net of tax	—	—	—	—	1.0
Discontinued operations, net of tax	—	—	—	—	1.0
Net income (loss)	1.6	154.8	(573.3)	(1,378.2)	310.3
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	29.6	5.9	(8.1)	(0.4)	(0.2)
Net income (loss) attributable to ENLK	$ (28.0)	$ 148.9	$ (565.2)	$ (1,377.8)	$ 310.5
Predecessor interest in net income	$ —	$ —	$ —	$ —	$ 35.5
General partner interest in net income	$ 38.6	$ 38.3	$ 39.5	$ 58.0	$ 138.3
Limited partners' interest in net income (loss) attributable to ENLK	$ (180.8)	$ 17.9	$ (662.1)	$ (1,405.2)	$ 136.7
Class C partners' interest in net loss attributable to ENLK	$ —	$ —	$ (12.5)	$ (30.6)	$ —
Series B preferred interest in net income attributable to ENLK	$ 90.2	$ 86.0	$ 69.9	$ —	$ —
Series C preferred interest in net income attributable to ENLK	$ 24.0	$ 6.7	$ —	$ —	$ —
Net income (loss) attributable to ENLK per limited partners' unit:					
Basic and diluted common unit	$ (0.51)	$ 0.05	$ (1.99)	$ (4.66)	$ 0.59
Distributions declared per limited partner unit	$ 1.560	$ 1.560	$ 1.560	$ 1.545	$ 1.470

(1) 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 consolidated the assets, liabilities, and operations of the legacy business of ENLK prior to giving effect to the Business Combination.

(2) Includes related party cost of sales of $114.1 million, $211.0 million, $150.1 million, $141.3 million, and $354.3 million for the years ended December 31, 2018, 2017, 2016, 2015, and 2014, respectively.

(3) Includes related party operating expense of $0.4 million, $0.6 million, $0.5 million, $0.5 million, and $5.9 million for the years ended December 31, 2018, 2017, 2016, 2015, and 2014, respectively.

(4) Includes related party general and administrative expenses of $11.6 million for the year ended December 31, 2014. Related party general and administrative expenses, if any, subsequent to December 31, 2014, were not material.

	EnLink Midstream Partners, LP				
	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions)				
Balance Sheet Data (end of period):					
Property and equipment, net	$ 6,846.7	$ 6,587.0	$ 6,256.7	$ 5,666.8	$ 5,042.8
Total assets	9,571.3	9,414.0	9,153.4	8,092.8	8,702.0
Long-term debt (including current maturities)	4,319.6	3,467.8	3,268.0	3,066.8	2,022.5
Partners' equity including non-controlling interest	4,284.1	4,805.5	4,640.4	4,434.5	6,025.9

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

Please read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report. In addition, please refer to the Definitions page set forth in this report prior to Item 1—Business.

In this report, the term "Partnership," as well as the terms "ENLK," "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 and EOGP.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.9 Bcf/d of processing capacity, seven fractionators with approximately 280,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments as of December 31, 2018:

- *Texas Segment.* The Texas segment includes our natural gas gathering, processing, and transmission operations in North Texas and the Permian Basin;

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering, processing, and transmission activities in the Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, STACK, and CNOW shale areas;

- *Louisiana Segment*. The Louisiana segment includes our natural gas pipelines, natural gas processing plants, storage facilities, fractionation facilities, and NGL assets located in Louisiana;

- *Crude and Condensate Segment.* The Crude and Condensate segment includes ORV, our crude oil operations in the Permian Basin and Central Oklahoma, and our crude oil activities associated with VEX; and

- *Corporate Segment*. The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our ownership interest in GCF in South Texas, and our general corporate property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to gather, process, transport, or market natural gas, NGLs, crude oil, and condensate using our assets for a fee. We earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodity purchase. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. We define gross operating margin as operating revenue minus cost of sales. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 88% of our gross operating margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the year ended December 31, 2018. We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

Devon is one of our primary customers. For the year ended December 31, 2018, approximately 36.4% of our gross operating margin was attributable to commercial contracts with Devon. For additional information about our significant customers, refer to "Item 1. Business—Credit Risks."

We generate revenues from eight primary sources:

- gathering and transporting natural gas, NGLs, and crude oil on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing recovered NGLs;
- providing compression services;
- providing crude oil and condensate transportation and terminal services;
- providing condensate stabilization services;
- providing brine disposal services; and
- providing natural gas, crude oil, and NGL storage.

Our gross operating margins are determined primarily by the volumes of:

- natural gas gathered, transported, purchased, and sold through our pipeline systems;
- natural gas processed at our processing facilities;
- NGLs handled at our fractionation facilities or transported through our pipeline systems;
- crude oil and condensate handled at our crude terminals;
- crude oil and condensate gathered, transported, purchased, and sold;
- condensate stabilized;
- brine disposed; and
- natural gas, crude oil, and NGLs stored.

We gather, transport, or store gas owned by others under fee-only contract arrangements based either on the volume of gas gathered, transported, or stored or, for firm transportation arrangements, a stated monthly fee for a specified monthly quantity with an additional fee based on actual volumes. We also buy natural gas from producers or shippers at a market index less a fee-based deduction subtracted from the purchase price of the natural gas. We then gather or transport the natural gas and sell the natural gas at a market index, thereby earning a margin through the fee-based deduction. We attempt to execute substantially all purchases and sales concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the fee we will receive for each natural gas transaction. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time, the supplies that we have under contract may decline due to reduced drilling or other causes, and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

On occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as “basis spread”), less the transportation expenses from the two areas, as our fee. Changes in the basis spread can increase or decrease our margins or potentially result in losses. For example, we are a party to one contract associated with our North Texas operations with a term ending June 2019 that requires us to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices and sell the gas into a different market-area index. We realize a cash loss on the delivery of gas under this contract each month based on current prices. The fair value of this performance obligation was recorded based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of December 31, 2018, the balance sheet reflects a liability of $9.0 million related to this performance obligation. Unfavorable basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

We typically buy mixed NGLs from our suppliers to our gas processing plants at a fixed discount to market indices for the component NGLs with a deduction for our fractionation fee. We subsequently sell the fractionated NGL products based on the same index-based prices. To a lesser extent, we transport and fractionate or store NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. The operating results of our NGL fractionation business are largely 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. We realize higher gross operating margins from product upgrades during periods with higher NGL prices.

We gather or transport crude oil and condensate owned by others by rail, truck, pipeline, and barge facilities under fee-only contract arrangements based on volumes gathered or transported. We also buy crude oil and condensate on Enlink’s own gathering systems, third-party systems, and trucked from producers at a market index less a stated transportation deduction. We then transport and resell the crude oil and condensate through a process of basis and fixed price trades. We execute substantially all purchases and sales concurrently, thereby establishing the net margin we will receive for each crude oil and condensate transaction.

We realize gross operating margins from our gathering and processing services primarily through different contractual arrangements: processing margin (“margin”) contracts, POL contracts, POP contracts, fixed-fee component contracts, or a combination of these contractual arrangements. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” for a detailed description of these contractual arrangements. Under any of these gathering and processing arrangements, we may earn a fee for the services performed, or we may buy and resell the gas and/or NGLs as part of the processing arrangement and realize a net margin as our fee.

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 increase or decrease significantly in the short term with increases or decreases in the volume of gas, liquids, crude oil, and condensate moved through or by our assets.

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 at its sole discretion.

Recent Developments

Simplification of the Corporate Structure. On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. See “Item 8. Financial Statements and Supplementary Data—Note 18—Subsequent Events” for more information on the Merger and related transactions.

Transfer of EOGP interest. On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership. See “Item 8. Financial Statements and Supplementary Data—Note 18—Subsequent Events” for more information regarding this transaction.

Strategic Partner Update. On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and ENLC’s managing member to GIP. See “Item 8. Financial Statements and Supplementary Data—Note 1—Organization and Summary of Significant Agreements” for more information regarding the GIP Transaction.

Organic Growth

Cajun-Sibon Pipeline. In 2018, we commenced an expansion of our Cajun-Sibon NGL pipeline capacity, which connects the Mont Belvieu NGL hub to our fractionation facilities in Louisiana. This is the third phase of our Cajun-Sibon system referred to as Cajun Sibon III, which will increase throughput capacity from 130,000 bbls/d to 185,000 bbls/d. We expect Cajun-Sibon III to be operational during the second quarter of 2019.

Avenger Crude Oil Gathering System. During 2018, we constructed a new crude oil gathering system in the northern Delaware Basin called Avenger. Avenger is supported by a long-term contract with Devon on dedicated acreage in their Todd and Potato Basin development areas in Eddy and Lea counties in New Mexico. We commenced initial operations on Avenger during the third quarter of 2018 and expect to begin full-service operations during the third quarter of 2019.

Central Oklahoma Plants. In December 2017, we commenced construction on our Thunderbird Plant to expand our Central Oklahoma processing capacity by an additional 200 MMcf/d gas processing plant. We expect to begin operations on the Thunderbird Plant during the second quarter of 2019.

Central Oklahoma Crude Oil Gathering Systems. In late March 2018, we completed construction of the first phase of Black Coyote. Black Coyote expands our operations in the core of the STACK play in Central Oklahoma and was built primarily to service acreage dedicated from Devon, which is the anchor customer on the system. In addition, we further expanded our crude oil gathering operations in the STACK through the construction of Redbud, which is supported by a contract with Marathon Oil Company. We commenced initial operations on Redbud during the third quarter of 2018.

Lobo Natural Gas Gathering and Processing Facilities. During the second quarter of 2018, we completed construction of an expansion to our Lobo II cryogenic gas processing plant, which brought total operational processing capacity at our Lobo facilities to 175 MMcf/d. We further expanded our natural gas processing capacity at our Lobo facilities through the construction of the Lobo III cryogenic gas processing plant, which was completed during the fourth quarter of 2018. Lobo III provides an additional 100 MMcf/d of operational capacity. An additional 100 MMcf/d of operational capacity will be completed during the first quarter of 2019.

Debt Issuances and Redemption

Term Loan. On December 11, 2018, ENLK entered into a three-year$850.0 million unsecured term loan. Upon closing of the Merger, ENLC assumed ENLK's obligations under the term loan, and ENLK guaranteed ENLC's obligation thereunder. See "Item 8. Financial Statements and Supplementary Data—Note 6—Long-Term Debt" for more information regarding this transaction.

Consolidated Credit Facility. On December 11, 2018, ENLC entered into the Consolidated Credit Facility, which was available upon the closing of the Merger. Upon closing of the Merger, ENLK became a guarantor of the Consolidated Credit Facility. See "Item 8. Financial Statements and Supplementary Data—Note 6—Long-Term Debt" for more information regarding this transaction.

Redemption of Senior Unsecured Notes due 2022. On June 1, 2017, we redeemed $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes (the "2022 Notes") at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which resulted in a gain on extinguishment of debt of $9.0 million for the year ended December 31, 2017.

Issuance of 2047 Notes. On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 (the "2047 Notes") at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under the ENLK Credit Facility and for general partnership purposes.

Issuance of 2026 Notes. On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under the ENLK Credit Facility and for general partnership purposes.

All of our outstanding senior notes were unaffected by the Merger.

Equity Issuances

Issuance of Common Units. For the year ended December 31, 2018,we sold an aggregate of 2.6 million common units under the 2017 EDA, generating proceeds of$46.1 million (net of $0.5 million of commissions paid to the Sales Agents).We used the net proceeds for general partnership purposes. In connection with the announcement of the Merger, we suspended solicitation and offers under the 2017 EDA. Following the consummation of the Merger, the 2017 EDA was terminated.

Issuance of Series C Preferred Units. In September 2017, we issued 400,000 Series C Preferred Units representing our limited partner interests at a price to the public of $1,000 per unit. We used the net proceeds of $394.0 million for capital expenditures, general partnership purposes, and to repay borrowings under the ENLK Credit Facility. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September, and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%.

The Series C Preferred Units were unaffected by the Merger and remain outstanding.

Issuance of Series B Preferred Units. In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units representing our limited partner interests to Enfield in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the acquisition of our EOGP assets. Affiliates of Goldman Sachs and affiliates of TPG own interests in the general partner of Enfield. Prior to the close of the Merger on January 25, 2019, the Series B Preferred Units were convertible into our common units on a one-for-one basis, subject to certain adjustments, (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") was greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Series B Preferred Units would have automatically converted into a number of common units equal to the greater of (i) the number of common units into which the Series B Preferred Units would then convert and (ii) the number of Series B Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

The Series B Preferred Units will continue to be issued and outstanding following the Merger, except that certain terms of the Series B Preferred Units have been modified pursuant to an amended partnership agreement of ENLK. Subsequent to the modification, Series B Preferred Units will be exchangeable for ENLC common units in an amount equal to the number of outstanding Series B Preferred Units outstanding multiplied by the exchange ratio of 1.15, subject to certain adjustments (the "Series B Exchange Ratio"). The exchange is subject to ENLK's option to pay cash instead of issuing additional ENLC common units, and can occur in whole or in part at Enfield's option at any time, or in whole at our option, provided the daily volume-weighted average closing price of the ENLC common units (the "ENLC VWAP") exchange for the 30 trading days ending two trading days prior to the exchange is greater than 150% of the Issue Price divided by the conversion ratio of 1.15.

For each of the calendar quarters between March 31, 2016 through June 30, 2017, Enfield received a quarterly distribution equal to an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Series B Preferred Units. Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions are payable quarterly in cash at an amount equal to $0.28125 per Series B Preferred Unit (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Series B Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price.

Beginning with the quarter ending March 31, 2019, the holder of the Series B Preferred Units will be entitled to quarterly cash distributions and distributions in-kind of additional Series B Preferred Units as described below. The quarterly in-kind distribution (the "Series B PIK Distribution") will equal the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) the number of Series B Preferred Units equal to the quotient of (x) the excess (if any) of (1) the distribution that would have been payable by ENLC had the Series B Preferred Units been exchanged for ENLC common units but applying a one-to-one exchange ratio (subject to certain adjustments) instead of the Series B Exchange Ratio, over (2) the Cash Distribution Component, divided by (y) the Issue Price. The quarterly cash distribution will consist of the Cash Distribution Component plus an amount in cash that will be determined based on a comparison of the value (applying the Issue Price) of (i) the Series B PIK Distribution and (ii) the Series B Preferred Units that would have been distributed in the Series B PIK Distribution if such calculation applied the Series B Exchange Ratio instead of the one-to-one ratio (subject to certain adjustments).

Acquisitions, Organic Growth, and Asset Sales in 2016 and 2017

- In January 2016, ENLK and ENLC acquired an 83.9% and 16.1% interest, respectively, in EOGP for aggregate consideration of approximately $1.4 billion. The EOGP assets serve gathering and processing needs in the growing STACK and CNOW plays in Central Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that, at the time of acquisition, had a weighted-average term of approximately 15 years.

- In April 2016, we completed construction of the 100 MMcf/d Riptide processing plant in the Permian Basin.

- In August 2016, we formed the Delaware Basin JV with NGP to operate and expand our natural gas, natural gas liquids, and crude oil midstream assets in the Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP.

- In October 2016, we completed construction of 60 MMcf/d of processing facilities for the initial phase of Lobo II. In the second quarter of 2017, we completed construction of an expansion of the Lobo II processing facility, which provided an additional 60 MMcf/d of processing capacity.

- In November 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., which consists of gathering and compression assets in Blaine County, Oklahoma. We hold a 30% ownership interest of the Cedar Cove JV, and Kinder Morgan, Inc. holds the remaining 70% ownership interest.

- In December 2016, we sold NTPL, a 140-mile natural gas transportation pipeline, for $84.6 million. We maintain capacity on the NTPL at competitive rates and at levels sufficient to support current and expected operations. As a result of the sale, we recorded a loss of $13.4 million for the year ended December 31, 2016.

- In March 2017, we completed construction and began operations of the Greater Chickadee crude oil gathering system.

- In March 2017, we completed the sale of our ownership interest in HEP for net proceeds of $189.7 million. For the year ended December 31, 2016, we recorded an impairment of $20.1 million to reduce the carrying value of our investment to the expected sales price. Upon the sale of HEP in March 2017, we recorded an additional loss of $3.4 million for the year ended December 31, 2017 based on the adjusted sales price at closing.

- In April 2017, we completed construction and began operating a new NGL pipeline through the Ascension JV. This NGL pipeline is a bolt-on project to our Cajun-Sibon NGL pipeline system and is supported by long-term, fee-based contracts with an affiliate of Marathon Petroleum Corporation.

- In June 2017, we entered into a long-term, fee-based arrangement with an affiliate of ONEOK, Inc. ("ONEOK") under which ONEOK transports NGLs from our Chisholm processing facility to the Gulf Coast and our Cajun-Sibon NGL pipeline system.

- In 2017, we completed construction of two new cryogenic gas processing plants, which included the Chisholm II plant completed in April 2017 and the Chisholm III plant completed in December 2017.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, and depreciation and amortization (“adjusted EBITDA”), distributable cash flow available to common unitholders (“distributable cash flow”), and gross operating margin.

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus interest expense, provision (benefit) for income taxes, depreciation, and amortization expense, impairments, unit-based compensation, (gain) loss on non-cash derivatives, (gain) loss on disposition of assets, (gain) loss on extinguishment of debt, successful transaction costs, accretion expense associated with asset retirement obligations, reimbursed employee costs, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, income (loss) from unconsolidated affiliate investments, and non-cash revenue from contract restructuring. Adjusted EBITDA is a primary metric used in our short-term incentive program for compensating employees. In addition, adjusted EBITDA is used as a supplemental liquidity and 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 financial performance of our assets without regard to financing methods, capital structure, or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, and make cash distributions to our unitholders and our general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The GAAP measures most directly comparable to adjusted EBITDA are net income (loss) and net cash provided by operating activities. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by 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 companies 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 net income (loss) and net cash provided by operating activities as determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following tables reconcile adjusted EBITDA to the most directly comparable GAAP measure for the periods indicated (in millions):

	Year Ended December 31,		
	2018	2017	2016
Reconciliation of net income (loss) to adjusted EBITDA			
Net income (loss)	$ 1.6	$ 154.8	$ (573.3)
Interest expense, net of interest income	178.3	187.9	188.1
Depreciation and amortization	577.3	545.3	503.9
Impairments	365.8	17.1	566.3
(Income) loss from unconsolidated affiliate investments (1)	(13.3)	(9.6)	19.9
Distributions from unconsolidated affiliate investments (2)	22.7	13.5	25.0
Loss on disposition of assets	0.4	—	13.2
Gain on extinguishment of debt	—	(9.0)	—
Unit-based compensation	40.8	47.8	30.0
Income tax provision (benefit)	(2.1)	(24.0)	1.3
(Gain) loss on non-cash derivatives	(10.1)	(4.7)	20.1
Payments under onerous performance obligation offset to other current and long-term liabilities	(17.9)	(17.9)	(17.9)
Non-cash revenue from contract restructuring (3)	(45.5)	—	—
Other (4)	3.3	4.6	6.9
Adjusted EBITDA before non-controlling interest	1,101.3	905.8	783.5
Non-controlling interest share of adjusted EBITDA (5)	(59.5)	(33.0)	(8.9)
Adjusted EBITDA, net to ENLK	$ 1,041.8	$ 872.8	$ 774.6

(1) Includes losses of $3.4 million and $20.1 million for the years ended December 31, 2017 and 2016, respectively, related to the sale of our HEP interests.

(2) Distributions for the year ended December 31, 2016 do not include $32.7 million of distributions received from HEP during the third quarter of 2016 attributable to the redemption of preferred units in HEP. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(3) In May 2018, we restructured a natural gas gathering and processing contract, and, as a result, recognized non-cash revenue representing the discounted present value of a secured term loan receivable. For more information, see “Item 8. Financial Statements—Note 2—Significant Accounting Policies.”

(4) Includes accretion expense associated with asset retirement obligations; reimbursed employee costs from Devon and LPC Crude Oil Marketing LLC; successful transaction costs, which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs; and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(5) Non-controlling interest share of adjusted EBITDA includes ENLC’s 16.1% share of adjusted EBITDA from EOGP, which was acquired in January 2016, NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV, which was formed in August 2016, Marathon Petroleum Corporation’s 50% share of adjusted EBITDA from the Ascension JV, which began operations in April 2017, and other minor non-controlling interests.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA, net to ENLK, less interest expense (excluding amortization of the EOGP acquisition installment payable discount), litigation settlement adjustment, adjustments for the redeemable non-controlling interest, interest rate swaps, current income taxes and other non-distributable cash flows, accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid, and maintenance capital expenditures, excluding maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities. Distributable cash flow is used as a supplemental liquidity 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 common unitholders and our general partner.

Maintenance capital expenditures include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines, gathering assets, well connections, compression assets, and processing assets up to their original operating capacity, to maintain pipeline and equipment reliability, integrity, and safety, and to address environmental laws and regulations.

The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities, or any other measure of liquidity presented in accordance with GAAP. Distributable cash flow has important limitations because it excludes some items that affect net income (loss), operating income (loss), and net cash provided by operating activities. Distributable cash flow may not be comparable to similarly-titled measures of other companies because other companies may not calculate distributable cash flow in the same manner. To compensate for these limitations, we believe that it is important to consider net cash provided by operating activities determined under GAAP, as well as distributable cash flow, to evaluate our overall liquidity.

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

	Year Ended December 31,		
	2018	2017	2016
Net cash provided by operating activities	$ 856.8	$ 706.5	$ 662.6
Interest expense (1)	177.9	158.8	135.3
Current income tax expense	1.8	2.6	1.9
Distributions from unconsolidated affiliate investment in excess of earnings (2)	6.9	0.2	21.9
Other (3)	4.4	6.3	4.2
Changes in operating assets and liabilities which (provided) used cash:			
Accounts receivable, accrued revenues, inventories, and other	126.8	213.2	107.7
Accounts payable, accrued gas and crude oil purchases, and other (4)	(73.3)	(181.8)	(150.1)
Adjusted EBITDA before non-controlling interest	1,101.3	905.8	783.5
Non-controlling interest share of adjusted EBITDA (5)	(59.5)	(33.0)	(8.9)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 1,041.8	$ 872.8	$ 774.6
Interest expense, net of interest income	(178.3)	(187.9)	(188.1)
Amortization of EOGP installment payable discount included in interest expense (6)	0.5	26.4	52.3
Litigation settlement adjustment (7)	—	(18.1)	—
Non-cash adjustment for redeemable non-controlling interest	—	—	0.3
Interest rate swap (8)	—	—	0.4
Current taxes and other	(4.7)	(2.5)	(1.9)
Maintenance capital expenditures, net to ENLK (9)	(42.0)	(30.9)	(30.5)
Preferred unit accrued cash distributions (10)	(89.4)	(38.7)	—
Distributable cash flow	$ 727.9	$ 621.1	$ 607.1

(1) Excludes non-cash interest income and amortization of debt issuance costs and discount and premium.
(2) Distributions for the year ended December 31, 2016 do not include $32.7 million of distributions received from HEP during the third quarter of 2016 attributable to the redemption of preferred units in HEP. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.
(3) Includes non-cash rent, which relates to lease incentives pro-rated over the lease term, accruals for settled commodity swap transactions, gains and losses on settled interest rate swaps designated as hedges related to debt issuances, which are recorded in other comprehensive income (loss), and successful transaction costs.
(4) Net of payments under onerous performance obligation offset to other current and long-term liabilities.
(5) Non-controlling interest share of adjusted EBITDA includes ENLC's 16.1% share of adjusted EBITDA from EOGP, which was acquired in January 2016, NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, which was formed in August 2016, Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV, which began operations in April 2017, and other minor non-controlling interests
(6) Amortization of the EOGP installment payable discount was considered non-cash interest under the ENLK Credit Facility since the payment under the payable is consideration for the acquisition of the EOGP assets.
(7) Represents recoveries from a lawsuit settled in 2017 for amounts not previously deducted from distributable cash flow. See "Item 8. Financial Statements—Note 13—Commitments and Contingencies" for additional information.
(8) During the third quarter of 2016, we entered into interest rate swap arrangement 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 is therefore excluded from distributable cash flow.
(9) Excludes maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(10) Represents the cash distributions earned by the Series B Preferred Units of $65.4 million and $32.0 million for the years ended December 31, 2018 and 2017 respectively, and $24.0 million and $6.7 million earned by the Series C Preferred Units for the year ended December 31, 2018 and 2017, respectively. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders. See "Item 8. Financial Statements—Note 8—Partners' Capital" for additional information.

Gross Operating Margin

We define gross operating margin as revenues less cost of sales. We present gross operating margin by segment in “Results of Operations.” We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because, in general, our business is to gather, process, transport, or market natural gas, NGLs, condensate, and crude oil for a fee or to purchase and resell natural gas, NGLs, condensate, and crude oil for a margin. Operating expense is a separate measure used by our 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. The GAAP measure most directly comparable to gross operating margin is operating income (loss). Gross operating margin should not be considered an alternative to, or more meaningful than, operating income (loss) as determined in accordance with GAAP. Gross operating margin has important limitations because it excludes all operating costs that affect operating income (loss) except cost of sales. 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 operating income (loss) to gross operating margin (in millions):

	Year Ended December 31,		
	2018	**2017**	**2016**
Operating income (loss)	$ 163.9	$ 299.5	$ (364.3)
Add (deduct):			
Operating expenses	453.4	418.7	398.5
General and administrative expenses	130.2	123.5	119.3
Loss on disposition of assets	0.4	—	13.2
Depreciation and amortization	577.3	545.3	503.9
Impairments	365.8	17.1	566.3
Gain on litigation settlement	—	(26.0)	—
Gross operating margin	$ 1,691.0	$ 1,378.1	$ 1,236.9

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 revenue less cost of sales as reflected in the table below (in millions, except volumes):

	Year Ended December 31,		
	2018	2017	2016
Texas Segment			
Revenues	$ 1,394.6	$ 1,365.9	$ 1,068.3
Cost of sales	(753.9)	(772.3)	(483.4)
Total gross operating margin	$ 640.7	$ 593.6	$ 584.9
Louisiana Segment			
Revenues	$ 3,501.2	$ 2,931.6	$ 2,001.5
Cost of sales	(3,158.7)	(2,618.1)	(1,729.0)
Total gross operating margin	$ 342.5	$ 313.5	$ 272.5
Oklahoma Segment			
Revenues	$ 1,297.7	$ 874.8	$ 437.0
Cost of sales	(744.0)	(522.9)	(184.9)
Total gross operating margin	$ 553.7	$ 351.9	$ 252.1
Crude and Condensate Segment			
Revenues	$ 2,745.3	$ 1,453.6	$ 1,176.5
Cost of sales	(2,596.4)	(1,330.3)	(1,038.0)
Total gross operating margin	$ 148.9	$ 123.3	$ 138.5
Corporate Segment			
Revenues	$ (1,239.8)	$ (886.3)	$ (430.9)
Cost of sales	1,245.0	882.1	419.8
Total gross operating margin	$ 5.2	$ (4.2)	$ (11.1)
Total			
Revenues	$ 7,699.0	$ 5,739.6	$ 4,252.4
Cost of sales	(6,008.0)	(4,361.5)	(3,015.5)
Total gross operating margin	$ 1,691.0	$ 1,378.1	$ 1,236.9
Midstream Volumes:			
Texas Segment			
Gathering and Transportation (MMBtu/d)	2,255,800	2,262,900	2,622,600
Processing (MMBtu/d)	1,279,100	1,184,400	1,173,100
Louisiana Segment			
Gathering and Transportation (MMBtu/d)	2,196,200	1,995,800	1,676,600
Processing (MMBtu/d)	431,200	453,300	490,300
NGL Fractionation (Gals/d)	6,584,400	5,772,800	5,197,100
Oklahoma Segment			
Gathering and Transportation (MMBtu/d)	1,204,700	829,300	626,300
Processing (MMBtu/d)	1,195,300	810,300	574,900
Crude and Condensate Segment			
Crude Oil Handling (Bbls/d)	155,400	108,200	94,000
Brine Disposal (Bbls/d)	3,200	4,200	3,600

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Gross Operating Margin. Gross operating margin was $1,691.0 million for the year ended December 31, 2018 compared to $1,378.1 million for the year ended December 31, 2017, an increase of $312.9 million, or 22.7%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $47.1 million, which was primarily due to a $42.7 million increase from our Permian Basin processing assets as a result of higher volumes due to continued development by our customers. In addition, there was a $4.4 million increase in gross operating margin from our North Texas processing, gathering, and transmission assets due to volume increases associated with new development in the Barnett Shale. For the year ended December 31, 2018, the shortfall revenue from Devon-related MVCs was $84.3 million compared to $59.2 million for the year ended December 31, 2017.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $29.0 million, which was primarily due to an increase in our NGL transmission and fractionation gross operating margin due to additional NGL volumes received from our Oklahoma and Permian Basin assets and fees earned from the start-up of our Ascension JV assets in April 2017.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $201.8 million, which was primarily due to a $156.3 million increase from higher volumes as a result of continued development by our customers. In addition, during the year ended December 31, 2018, we restructured a contract with a customer, which resulted in the recognition of $45.5 million in revenue for the year ended December 31, 2018 (as discussed in "Item 8. Financial Statements—Note 2—Significant Accounting Policies"). For the year ended December 31, 2018, the shortfall revenue from Devon-related MVCs was $1.2 million compared to $13.8 million for the year ended December 31, 2017.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment increased $25.6 million, which was partially due to a $14.9 million increase from ORV due to higher condensate stabilization volumes and improved margins from contract renegotiations. In addition, there was a $5.9 million increase from our Permian Basin crude business as a result of increased trucking volumes, higher trucking fees, higher volumes due to continued expansion of our customer base on the Greater Chickadee gathering system, and the start of initial operations of Avenger. Additionally, gross operating margin increased $2.5 million from the start of initial operations of our Central Oklahoma crude oil gathering systems and trucking business, and $2.3 million due to higher volumes on VEX.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $9.4 million, due to the changes in fair value of our commodity swaps between the periods. For the year ended December 31, 2018, there were realized losses of $4.9 million that were offset by unrealized gains of $10.1 million. For the year ended December 31, 2017, there were realized losses of $8.9 million that were partially offset by unrealized gains of $4.7 million.

Certain gathering and processing agreements in our Texas, Oklahoma, and Crude and Condensate segments provide for quarterly or annual MVCs, including MVCs from Devon from certain of our Barnett Shale assets in North Texas and our Cana gathering and processing assets in Oklahoma. Under these agreements, our customers or suppliers (as "customers" and "suppliers" are determined per application of ASC 606) agree to ship and/or process a minimum volume of product on our systems over an agreed time period. If a customer or supplier under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual product volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer or supplier to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in subsequent periods. Deficiency fee revenue is included in midstream services revenue.

Revenue recorded for the shortfall between actual product volumes the MVCs were as follows (in millions):

	Texas	Oklahoma	Crude and Condensate	Total
Year Ended December 31, 2018				
Midstream services (1)	$ 41.0	$ 53.4	$ 5.2	$ 99.6
Midstream services—related parties	43.3	1.2	6.3	50.8
Total	$ 84.3	$ 54.6	$ 11.5	$ 150.4
Year Ended December 31, 2017				
Midstream services	$ 0.8	$ 16.1	$ —	$ 16.9
Midstream services—related parties	59.2	13.8	8.9	81.9
Total	$ 60.0	$ 29.9	$ 8.9	$ 98.8

(1) We restructured a natural gas gathering and processing contract that contained MVCs. As a result, we recognized $45.5 million of midstream services revenue in the Oklahoma segment for the year ended December 31, 2018. For more information, see "See "Item 8. Financial Statements and Supplementary Data—Note 2—Significant Accounting Policies."

On January 1, 2019, certain MVCs related to gathering and processing agreements with Devon for operations in the Texas and Oklahoma segments expired. These MVCs generated $85.5 million and $73.0 million in shortfall revenue for the years endedDecember 31, 2018 and 2017, respectively. Additionally, on July 31, 2019, an MVC related to a transportation services agreement with Devon for operations in the Crude and Condensate segment will expire. This MVC generated $11.5 million and $8.9 million in shortfall revenue for the years ended December 31, 2018 and 2017, respectively. For 2019, we expect revenues to decline related to the expired MVC agreements in the Texas and Oklahoma segments and the expiring MVC agreements in the Crude and Condensate segment. For additional information, refer to "Item 1. Business—Our Assets."

Operating Expenses. Operating expenses were $453.4 million for the year ended December 31, 2018 compared to $418.7 million for the year ended December 31, 2017, an increase of $34.7 million, or 8.3%. The primary contributors to the total increase by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2018	2017	$	%
Texas Segment	$ 180.6	$ 172.7	$ 7.9	4.6 %
Louisiana Segment	108.3	101.3	7.0	6.9 %
Oklahoma Segment	89.2	64.6	24.6	38.1 %
Crude and Condensate Segment	75.3	80.1	(4.8)	(6.0)%
Total	$ 453.4	$ 418.7	$ 34.7	8.3 %

- *Texas Segment.* Operating expenses in the Texas segment increased $7.9 million primarily due to expanded operations and higher utilities expense in the Permian Basin.

- *Louisiana Segment.* Operating expenses in the Louisiana segment increased $7.0 million primarily due to increased utilities, operational fees and services, labor and benefits charges, and materials and supplies expenses as a result of the start-up of the Ascension JV in April 2017 and higher volumes across our Louisiana assets.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $24.6 million due to labor and benefit expenses from increased headcount, as well as an increase in materials and supplies, operational fees and services, treater rentals, ad valorem tax, and compression service expenses as a result of expanded operations.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $4.8 million primarily due to decreases in third-party transportation charges and lower labor and benefit expenses.

General and Administrative Expenses. General and administrative expenses were $130.2 million for the year ended December 31, 2018 compared to $123.5 million for the year ended December 31, 2017, an increase of $6.7 million, or 5.4%. The primary contributors to the increase were as follows:

- Wages and salaries increased due to a $9.3 million increase in bonus expense as a result of strong financial performance and $2.8 million in severance expense related to an organizational realignment in 2018;
- Transaction costs increased $3.1 million due to costs we incurred in 2018 related to the GIP Transaction and the Merger;
- Unit-based compensation expense decreased $7.0 million due to bonuses paid in the form of units, which vested immediately in March 2017, and was partially offset by accelerated vesting of units related to the GIP Transaction and an organizational realignment in 2018; and
- Professional service fees decreased $1.0 million.

Depreciation and Amortization. Depreciation and amortization expenses were $577.3 million for the year ended December 31, 2018 compared to $545.3 million for the year ended December 31, 2017, an increase of $32.0 million, or 5.9%. This increase was primarily due to increased depreciation expense of $21.3 million, $4.2 million, and $2.0 million from completed projects at our Central Oklahoma, Delaware JV, and ORV assets, respectively, and accelerated depreciation expense due to a change in the useful lives of certain underutilized assets in our Louisiana segment of $4.2 million.

Impairments. Impairment expense was $365.8 million for the year ended December 31, 2018 compared to impairment expense of $17.1 million for the year ended December 31, 2017, an increase of $348.7 million. For the year ended December 31, 2018, we recognized impairments on property and equipment related to the carrying values of certain non-core natural gas assets in the Louisiana segment of $24.6 million and $109.2 million related to non-core crude pipeline assets in the Crude and Condensate segment. In addition, we recognized a goodwill impairment for our Texas reporting unit of $232.0 million. See "Item 8. Financial Statements—Note 4—Goodwill and Intangible Assets" for additional information. For the year ended December 31, 2017, we recognized a $17.1 million impairment on property and equipment, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

Gain on Litigation Settlement. We recognized a gain on litigation settlement of $26.0 million for the year ended December 31, 2017. See "Item 8. Financial Statements—Note 13—Commitments and Contingencies" for additional information.

Gain on Extinguishment of Debt. We recognized a gain on extinguishment of debt of $9.0 million for the year ended December 31, 2017 due to the redemption of the 2022 Notes. See "Item 8. Financial Statements—Note 6—Long-Term Debt" for additional information.

Interest Expense. Interest expense was $178.3 million for the year ended December 31, 2018 compared to $187.9 million for the year ended December 31, 2017, a decrease of $9.6 million, or 5.1%. Net interest expense consisted of the following (in millions):

	Year Ended December 31,	
	2018	**2017**
Senior notes	$ 160.0	$ 155.0
Term Loan	1.9	—
ENLK Credit Facility	22.3	9.5
Capitalized interest	(7.0)	(6.3)
Amortization of debt issue costs and net discount	4.0	29.1
Other	(2.9)	0.6
Total interest expense, net of interest income	$ 178.3	$ 187.9

Income (loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $13.3 million for the year ended December 31, 2018 compared to income of $9.6 million for the year ended December 31, 2017, an increase of $3.7 million. The increase was primarily due to additional income of $3.2 million from our GCF investment as a result of higher fractionation revenues and lower operating expenses and a $3.4 million loss on the sale of our HEP investment for the year ended December 31, 2017. These increases were offset by a $2.9 million decrease in income from our Cedar Cove JV for the year ended December 31, 2018.

Income Tax Benefit (Expense). Income tax benefit was $2.1 million for the year ended December 31, 2018 compared to income tax benefit of $24.0 million for the year ended December 31, 2017, a decrease of tax benefit of $21.9 million primarily due to a change in tax rates. On December 22, 2017, the Tax Cuts and Jobs Act was signed into legislation and resulted in a change in the federal statutory corporate rate from 35% to 21%, effective January 1, 2018. We recognized a tax benefit of $24.9 million during the fourth quarter of 2017 due to the re-measurement of our deferred tax liabilities to reflect the reduction in the federal statutory corporate rate.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Gross Operating Margin. Gross operating margin was $1,378.1 million for the year ended December 31, 2017 compared to $1,236.9 million for the year ended December 31, 2016, an increase of $141.2 million, or 11.4%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $8.7 million, which was primarily due to a $25.9 million increase in gross operating margin due to higher volumes from our expansion in the Permian Basin. This increase was partially offset by a $17.2 million decrease in gross operating margin from our North Texas processing, gathering, and transmission assets due to volume declines across our North Texas system, including an $11.5 million decrease due to the sale of the NTPL assets in December 2016. Although we experienced volume declines for certain of our Barnett-Shale assets, the impact of these volume declines on gross operating margin was offset by an increase in revenue earned from MVCs (as discussed in more detail below) under our contracts with Devon. For the year ended December 31, 2017 the shortfall revenue from Devon-related MVCs was $59.2 million compared to $26.4 million for the year ended December 31, 2016.

- *Louisiana Segment*. Gross operating margin in the Louisiana segment increased $41.0 million, which was primarily due to a $34.2 million increase in gross operating margin from our NGL transmission and fractionation assets and a $6.8 million increase in gross operating margin from our Louisiana gathering and transmission assets. The increase from our NGL business was primarily due to additional NGL volumes fractionated, including volumes received from our Oklahoma and Permian Basin assets, together with a $9.3 million gross operating margin contribution from fees earned on our Ascension JV assets, which commenced operations in April 2017. The increase from our transmission assets was primarily due to volume increases on our Louisiana Intrastate Gas and Gulf Coast pipeline systems.

- *Oklahoma Segment*. Gross operating margin in the Oklahoma segment increased $99.8 million, which was primarily driven by a $104.8 million increase from our Central Oklahoma assets as a result of higher volumes due to continued producer development in Oklahoma. This increase was partially offset by a $5.1 million decrease in gross operating margin from our Northridge gathering and processing assets due to price and volume reductions under a third-party contract.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $15.2 million, which was primarily due to a $12.8 million decrease as a result of condensate stabilization volume declines and transportation rate decreases on our ORV assets and a decrease of $8.4 million as a result of volume declines in our Permian Basin trucking business. The volume and rate declines throughout our Crude and Condensate segment were primarily attributable to increased competition due to lower crude prices. These declines were partially offset by a $4.8 million increase due to the Greater Chickadee gathering system, which became fully operational in the first quarter of 2017.

- *Corporate Segment*. Gross operating margin in the Corporate segment increased $6.9 million, which was due to the changes in fair value of our commodity swaps between periods. For the year ended December 31, 2017, there were unrealized gains of $4.7 million, offset by realized losses of $8.9 million. For the year ended December 31, 2016, there were unrealized losses of $20.1 million, partially offset by realized gains of $9.0 million.

Operating Expenses. Operating expenses were $418.7 million for the year ended December 31, 2017 compared to$398.5 million for the year ended December 31, 2016, an increase of $20.2 million, or 5.1%. The primary contributors to the total increase by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2017	2016	$	%
Texas Segment	$ 172.7	$ 168.5	$ 4.2	2.5 %
Louisiana Segment	101.3	96.6	4.7	4.9 %
Oklahoma Segment	64.6	52.1	12.5	24.0 %
Crude and Condensate Segment	80.1	81.3	(1.2)	(1.5)%
Total	$ 418.7	$ 398.5	$ 20.2	5.1 %

- *Louisiana Segment*. Operating expenses in the Louisiana segment increased $4.7 million primarily due to increases in materials and supplies expense of $2.7 million, labor and benefits expense of $1.7 million, utilities expense of $1.3 million, and regulatory expense of $1.0 million as a result of increased activity on our Louisiana systems, partially offset by reduced compressor rental expense of $2.2 million resulting from the purchase of compressors.

- *Oklahoma Segment*. Operating expenses in the Oklahoma segment increased $12.5 million primarily due to increased property insurance costs of $5.4 million, increased labor and benefits expense of $3.5 million attributable to higher headcount, and to increased materials and supplies expense of $3.7 million as a result of expanded operations.

General and Administrative Expenses. General and administrative expenses were $123.5 million for the year ended December 31, 2017 compared to $119.3 million for the year ended December 31, 2016, an increase of $4.2 million, or 3.5%. The primary contributors to the increase were as follows:

- Unit-based compensation expense increased $13.7 million due to bonuses paid in the form of units, which vested immediately in March 2017, and the accrual of annual bonuses for 2017;

- Transaction costs decreased $3.8 million and transition service fees decreased $1.5 million due to the costs incurred during 2016 related to the EOGP acquisition, with no transaction or transition costs incurred for the year ended December 31, 2017; and

- Wages and salaries expense decreased $3.6 million due to severance payments made during 2016 and a decrease in bonus expenses for the year ended December 31, 2017.

Loss on Disposition of Assets. For the year ended December 31, 2016 we recorded a loss on disposition of assets of $13.2 million, which was primarily attributable to a $13.4 million loss on sale of the NTPL.

Depreciation and Amortization. Depreciation and amortization expenses were $545.3 million for the year ended December 31, 2017 compared to $503.9 million for the year ended December 31, 2016, an increase of $41.4 million, or 8.2%. Of this increase, $18.8 million was attributable to the plant expansion of our Permian Basin gathering and processing assets; $15.8 million was attributable to the expansion of our Central Oklahoma assets; $4.7 million was attributable to the Greater Chickadee gathering system; $3.4 million was attributable to the acceleration of depreciation for some North Texas compressor stations decommissioned during 2017; and $2.6 million was attributable to the Ascension JV assets. These increases were partially offset by a $4.3 million decrease in depreciation expense related to the sale of the NTPL in December 2016.

Impairments. Impairment expense was $17.1 million for the year ended December 31, 2017 compared to impairment expense of $566.3 million for the year ended December 31, 2016, a decrease of $549.2 million, or 97.0%. In the first quarter of 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments. For the year ended December 31, 2017, we recognized property and equipment impairments of $17.1 million, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

Interest Expense. Interest expense was $187.9 million for the year ended December 31, 2017 compared to $188.1 million for the year ended December 31, 2016, a decrease of $0.2 million, or 0.1%. Net interest expense consisted of the following (in millions):

	Year Ended December 31,	
	2017	2016
Senior notes	$ 155.0	$ 131.1
ENLK Credit facility	9.5	11.7
Capitalized interest	(6.3)	(7.2)
Amortization of debt issue costs and net discount	29.1	53.1
Cash settlements on interest rate swaps	—	(0.4)
Mandatory redeemable non-controlling interest	—	0.3
Other	0.6	(0.5)
Total interest expense, net of interest income	$ 187.9	$ 188.1

Income (loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $9.6 million for the year ended December 31, 2017 compared to a loss of $19.9 million for the year ended December 31, 2016, an increase of $29.5 million. The increase was primarily due to a $23.3 million loss from our investment in HEP for the year ended December 31, 2016 compared to a $3.4 million loss from the sale of HEP for the year ended December 31, 2017. The loss from our investment in HEP for the year ended December 31, 2016 was primarily due to the $20.1 million impairment of our investment in HEP in the fourth quarter of 2016 to reduce the carrying value of our investment to the expected sale price. In addition, we generated increased income of $9.2 million from our GCF investment for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to higher fractionation revenues and lower operating expenses.

Income Tax Benefit (Expense). Income tax benefit was $24.0 million for the year ended December 31, 2017 compared to income tax expense of $1.3 million for the year ended December 31, 2016, a decrease of tax expense of $25.3 million primarily due to a change in tax rates.

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 interpretation and implementation of existing rules and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules 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 “Item 8. Financial Statements and Supplementary Data—Note 2—Significant Accounting Policies” for further details on our accounting policies and future accounting standards to be adopted.

Revenue Recognition.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), which established ASC Topic 606, Revenue from Contracts with Customers. ASC 606 replaces previous revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 also requires significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles, including collectability, sales tax presentation, noncash consideration, contract modifications, and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied using the modified retrospective or full retrospective transition methods. We have adopted ASC 606 using the modified retrospective method for annual and interim reporting periods that began January 1, 2018.

Based on our review of our performance obligations in our contracts with customers, we changed the consolidated statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. For the year ended December 31, 2018, the reclassification of revenues and cost of sales resulted in a net decrease in revenue of approximately $671.0 million or 8.0%, compared to total revenues based on accounting prior to the adoption of ASC 606, with an equivalent net decrease in cost of sales. The change in total revenues as a result of the adoption of ASC 606 is made up of the following revenue line item changes (in millions):

	Increase (Decrease) in Revenue Due to ASC 606 Adoption	
	Year Ended December 31, 2018	
Product sales	$	(235)
Product sales—related parties		(52)
Midstream services		(357)
Midstream services—related parties		(27)
Total	$	(671)

This change in accounting treatment had no impact on our operating income, net income, results of operations, financial condition, or cash flows.

Impairment of Long-Lived Assets.

In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets, including related intangible assets, of identifiable business activities for potential impairment annually in the fourth quarter, and whenever events or changes in circumstances indicate that their carrying value 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 is recognized equal to the excess of the asset's carrying value over its fair value, which is based on inputs that are not observable in the market, and thus represent Level 3 inputs.

For the year ended December 31, 2018, we determined that the undiscounted cash flows for two of our assets were not in excess of their carrying values. We estimated the fair values of these assets and determined that their fair values were not in excess of their carrying values, which resulted in impairments on property and equipment of $24.6 million related to certain non-core natural gas pipeline assets in the Louisiana segment and $109.2 million related to non-core crude pipeline assets in the Crude and Condensate segment.

For the year ended December 31, 2017, we recognized a $17.1 million impairment on property and equipment, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well. There were no impairments on property and equipment recognized for the year ended December 31, 2016.

Impairment of Goodwill.

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business.We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform a goodwill impairment test. We may elect to perform a goodwill impairment test without completing a qualitative assessment.

Effective January 2017, we elected to early adopt ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)— Simplifying the Test for Goodwill Impairment*, which simplified the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in ASC 350, *Intangibles—Goodwill and Other*. As a result, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An impairment charge should be recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. However, the impairment recognized should not exceed the total amount of goodwill allocated to that reporting unit. Therefore, our annual impairment tests as of October 31, 2018 and October 31, 2017 were performed according to ASU 2017-04.

For additional information about our goodwill impairment tests, refer to "Item 8. Financial Statements and Supplementary Data—Note 4—Goodwill and Intangible Assets."

Goodwill Impairment Analysis for the Year Ended December 31, 2018

During our annual goodwill impairment test for 2018, which was performed as of October 31, 2018, we determined, based upon our qualitative assessment, that no impairments of goodwill were required as of that date. However, subsequent to October 31, 2018, we determined that due to a significant decline in our unit price, a change in circumstances had occurred that warranted a quantitative impairment test. Based on this triggering event, we performed a quantitative goodwill impairment analysis as of December 31, 2018. Based on this analysis, a goodwill impairment loss for our Texas reporting unit in the amount of $232.0 million was recognized in the fourth quarter of 2018 and is included in impairments in the consolidated statement of operations for the year ended December 31, 2018. Substantially all of the goodwill for our Texas reporting unit was recorded as a result of our Business Combination in March 2014.

We concluded that the fair value of our Oklahomareporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded forthe Oklahoma reporting unit as a result of our quantitative impairment test.

Goodwill Impairment Analysis for the Year Ended December 31, 2017

During our annual impairment test for 2017, performed as of October 31, 2017, we determined that no impairments were required for the year ended December 31, 2017.

Goodwill Impairment Analysis for the Year Ended December 31, 2016

During February 2016, we determined that continued weakness in the overall energy sector, driven by low commodity prices together with a decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as impairments in the consolidated statement of operations for the year ended December 31, 2016.

We concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analysis.

During our annual impairment test for 2016, performed as of October 31, 2016, we determined that no further impairments were required for the year ended December 31, 2016.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $856.8 million, $706.5 million, and $662.6 million for the years ended December 31, 2018, 2017, and 2016 respectively. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Operating cash flows before working capital	$ 928.2	$ 755.8	$ 638.1
Changes in working capital	(71.4)	(49.3)	24.5

Operating cash flows before changes in working capital increased $172.4 million for the year ended December 31, 2018 compared to the year ended December 31, 2017. This increase was primarily due to a $262.2 million increase in gross operating margin, excluding gains and losses on derivative activity and excluding non-cash revenue recognized from the restructuring of a contract (as discussed in "Item 8. Financial Statements—Note 2—Significant Accounting Policies"). The increase in operating cash flows was partially offset by a $15.5 million increase in interest expense, excluding amortization of debt issue costs and net discounts, as well as a $26.0 million gain on litigation settlement recognized for the year ended December 31, 2017. The remaining difference is due to higher cash paid for operating expenses and general and administrative expenses for the year ended December 31, 2018.

Operating cash flows before changes in working capital increased $117.7 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. This increase was primarily due to a $134.3 million increase in gross operating margin, excluding gains and losses on derivative activity, and a $26.0 million gain on litigation settlement, partially offset by a $23.8 million increase in interest expense, excluding amortization of debt issue costs and net discounts, and a $21.7 million decrease in cash received on derivative settlements.

The changes in working capital for the years ended December 31, 2018, 2017, and 2016 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments and changes in inventory balances attributable to normal operating fluctuations.

Cash Flows from Investing Activities. Net cash used in investing activities was $826.3 million, $610.8 million, and $1,358.1 million for the years ended December 31, 2018, 2017, and 2016, respectively. Our primary investing cash flows were as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Growth capital expenditures	$ (800.3)	$ (758.4)	$ (632.5)
Maintenance capital expenditures	(42.8)	(32.4)	(30.5)
Acquisition of business, net of cash acquired	—	—	791.5
Proceeds from sale of unconsolidated affiliate investment	—	189.7	—
Proceeds from sale of property	1.9	2.3	93.1
Investment in unconsolidated affiliates	(0.1)	(12.6)	(73.8)
Distribution from unconsolidated affiliates in excess of earnings	6.9	0.2	54.6

Growth capital expenditures increased $41.9 million for the year ended December 31, 2018 compared to the year ended December 31, 2017. The increase was primarily due to capital expenditures related to Avenger and the Lobo III gas processing plant in the Delaware Basin during 2018. Growth capital expenditures increased $125.9 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. The increase was primarily due to capital expenditures related to the expansion of the Central Oklahoma assets and the Lobo processing facilities, as well as expenditures for the Greater Chickadee crude oil gathering system in the Permian Basin and the Ascension JV assets in Louisiana.

Maintenance capital expenditures increased by $10.4 million for the year ended December 31, 2018 compared to the year ended December 31, 2017. The increase was primarily due to a larger asset base and timing of expenditures. Maintenance capital expenditures increased slightly by $1.9 million for the year ended December 31, 2017 compared to the year ended December 31, 2016.

There were no acquisitions for the years ended December 31, 2018 and 2017. For the year ended December 31, 2016, we acquired the EOGP assets.

In December 2016, we entered into an agreement to sell our ownership interest in HEP. We finalized the sale in March 2017 and received net proceeds of $189.7 million. We received proceeds from sale of property of $93.1 million for the year ended December 31, 2016. These proceeds were primarily from the sale of the NTPL in December 2016 for $84.6 million.

Investments and distributions from unconsolidated affiliate investments are determined by our contribution and distribution activity with our GCF, HEP, and Cedar Cove JV investments for the years ended December 31, 2018, 2017, and 2016. We formed the Cedar Cove JV with Kinder Morgan, Inc. during November 2016 and sold our ownership interest in our HEP investment during March 2017. See "Item 8. Financial Statements—Note 9—Investment in Unconsolidated Affiliates" for investment and distribution activity.

Cash Flows from Financing Activities. Net cash provided by financing activities were $38.2 million and $701.2 million for the years ended December 31, 2018 and 2016, respectively. Net cash used in financing activities was $76.5 million for the year ended December 31, 2017. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,		
	2018	2017	2016
Net repayments on the ENLK Credit Facility	$ —	$ (120.0)	$ (294.2)
Unsecured senior notes borrowings, net of notes extinguished	—	331.6	499.3
Proceeds from the Term Loan	850.0	—	—
Proceeds from issuance of common units	46.1	106.9	167.5
Proceeds from issuance of Series B Preferred Units	—	—	724.1
Proceeds from issuance of Series C Preferred Units	—	394.0	—
Contributions by non-controlling partners	156.4	126.4	207.4
Payment of installment payable for EOGP acquisition	(250.0)	(250.0)	—

On December 11, 2018, ENLK entered into a Term Loan due December 11, 2021, and used the net proceeds to repay borrowings under the ENLK Credit Facility. At the closing of the Merger, ENLC assumed the Term Loan, and ENLK became a guarantor of ENLC's obligations under the Term Loan. Also, at the closing of the Merger the ENLK Credit Facility was terminated and ENLK became a guarantor of the Consolidated Credit Facility. See "Item 8. Financial Statements—Note 6—Long-Term Debt" for additional information.

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 at a price to the public of 99.981% of their face value. The net proceeds of approximately $495.2 million were used to repay outstanding borrowings under the ENLK Credit Facility and for general partnership purposes. For the year ended December 31, 2017, we redeemed $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes due June 1, 2022 at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which included payments for accrued interest of $5.8 million.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our ENLK Credit Facility and for general partnership purposes.

For the year ended December 31, 2018, we sold an aggregate of 2.6 million common units under the 2017 EDA, generating proceeds of $46.1 million (net of $0.5 million of commissions paid to the Sales Agents). We used the net proceeds for general partnership purposes. In connection with the announcement of the Merger, we suspended solicitation and offers under the 2017 EDA. Following the consummation of the Merger, the 2017 EDA was terminated.

For the year ended December 31, 2017, we sold an aggregate of 6.2 million common units, generating net proceeds of $106.9 million. For the year ended December 31, 2016, we sold an aggregate of 10.0 million common units, generating net proceeds of $167.5 million.

In September 2017, we issued 400,000 Series C Preferred Units for net proceeds of $394.0 million. See "Item 8. Financial Statements—Note 8—Partners' Capital" for additional information.

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units for net proceeds of $724.1 million. See "Item 8. Financial Statements—Note 8—Partners' Capital" for additional information.

For the year ended December 31, 2018, contributions by non-controlling partners included $66.2 million from ENLC to EOGP and $90.5 million from NGP to the Delaware Basin JV. For the year ended December 31, 2017, contributions by non-controlling interests included $69.1 million from ENLC to EOGP, $54.4 million from NGP to the Delaware Basin JV, and $2.9 million from Marathon Petroleum Corporation to the Ascension JV. For the year ended December 31, 2016, contributions by non-controlling partners included $144.4 million in contributions from NGP to the Delaware Basin JV, which consisted of an initial contribution of $114.3 million that the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent up to the date of formation on existing assets, as well as $30.1 million for NGP's share of ongoing projects. Contributions by non-controlling partners in 2016 also included $39.5 million from ENLC for its share of costs incurred related to EOGP and $23.5 million from Marathon Petroleum Corporation to the Ascension JV.

For the years ended December 31, 2018 and 2017, we made the final two $250.0 million payments under the installment payable obligation related to the EOGP acquisition.

Distributions to unitholders, our general partner, and our non-controlling interests also represent a primary use of cash in financing activities. Total cash distributions made for the years ended December 31, 2018, 2017, and 2016 were as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Common units	$ 551.6	$ 543.6	$ 520.3
General partner interest (including incentive distribution rights)	61.9	61.2	58.7
Distributions to non-controlling interests (1)	54.5	27.5	10.0
Distributions to Series B Preferred Unitholders	65.0	15.9	—
Distributions to Series C Preferred Unitholders	24.0	5.6	—

(1) Distributions to non-controlling interests included distributions to ENLC for its ownership in EOGP, distributions to NGP for its ownership in the Delaware Basin JV, distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV, and distributions to the non-controlling interest in one of our joint ventures in ORV.

Series B Preferred Unit distributions for 2016 and for the first two quarters for 2017 were paid in-kind in the form of additional Series B Preferred Units. As these were non-cash distributions, they were not reflected in our financing cash flows for the years ended December 31, 2017 and 2016. For the period beginning with the quarter ended September 30, 2017 through the quarter ended December 31, 2018, we paid Series B Preferred Unit distributions in cash at an amount per quarter equal to $0.28125 per Series B Preferred Unit (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (a) 0.0025 Series B Preferred Units per Series B Preferred Unit and (b) an amount equal to (i) the excess, if any, of the distributions that would have been payable had the Series B Preferred Units converted into common units for that quarter over the Cash Distribution Component, divided by (ii) the issue price of $15.00.

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%.

Uncertainties. Our operations could be subject to changing environmental rules and regulations, the outcomes of which are currently unknown. See "Item 1. Business—Environmental Matters" for additional information.

Capital Requirements. We consider a number of factors in determining whether our capital expenditures are growth capital expenditures or maintenance capital expenditures. Growth capital expenditures generally include capital expenditures made for acquisitions or capital improvements that we expect will increase our asset base, operating income, or operating capacity over the long-term. Examples of growth capital expenditures include the acquisition of assets and the construction or development of additional pipeline, storage, well connections, gathering, or processing assets, in each case, to the extent such capital expenditures are expected to expand our asset base, operating capacity, or our operating income.

Maintenance capital expenditures include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines, gathering assets, well connections, compression assets, and processing assets up to their original operating capacity, or to maintain pipeline and equipment reliability, integrity, and safety and to address environmental laws and regulations.

We expect our 2019 growth capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be approximately $605 million to $775 million, of which we expect $40 million to $50 million to come from our joint venture partners. We expect our 2019 maintenance capital expenditures to be $40 million to $60 million. Our primary capital projects for 2019 include the completion of construction of the Thunderbird Plant, Avenger, the Lobo III processing plant in the Delaware Basin, the expansion of Cajun Sibon III, and continued development of our existing systems. See “Recent Developments” for further details.

We expect to fund growth capital expenditures from the proceeds of borrowings under the Consolidated Credit Facility, operating cash flows, and proceeds from other debt and equity sources, including capital contributions by joint venture partners that relate to the non-controlling interest share of our consolidated entities. We expect to fund our maintenance capital expenditures from operating cash flows. In 2019, it is possible that not all of our planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, 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, 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, 2018, 2017, and 2016.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2018 is as follows (in millions):

	Payments Due by Period						
	Total	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**
Long-term debt obligations (1)	$ 3,500.0	$ 400.0	$ —	$ —	$ —	$ —	$ 3,100.0
Term Loan	850.0	—	—	850.0	—	—	—
Interest payable on senior unsecured notes	2,413.5	154.5	149.2	149.2	149.2	149.2	1,662.2
Capital lease obligations	2.7	1.5	1.2	—	—	—	—
Operating lease obligations	100.3	14.1	10.3	8.7	8.6	8.8	49.8
Purchase obligations	29.3	29.3	—	—	—	—	—
Delivery contract obligation	9.0	9.0	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (2)	201.8	40.5	32.9	32.8	28.1	25.5	42.0
Inactive easement commitment (3)	10.0	—	—	—	10.0	—	—
Total contractual obligations	$ 7,116.6	$ 648.9	$ 193.6	$ 1,040.7	$ 195.9	$ 183.5	$ 4,854.0

(1) $400.0 million in aggregate principal amount of our 2.7% senior unsecured notes mature on April 1, 2019.
(2) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(3) Amounts related to inactive easements paid as utilized by us with balance due in 2022 if not utilized.

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

The interest payable under the Consolidated Credit Facility and the Term Loan are not reflected in the above table because such amounts depend on the outstanding balances and interest rates of the Consolidated Credit Facility and the Term Loan, which vary from time to time.

Our contractual cash obligations for the remainder of 2019 are expected to be funded from cash flows generated from our operations, asset sales, and other debt and equity sources.

Indebtedness

Prior to the closing of the Merger, we had a $1.5 billion unsecured revolving credit facility that matured on March 6, 2020, which included a $500.0 million letter of credit subfacility. As of December 31, 2018, we had no borrowings under the ENLK Credit Facility, and there were $9.8 million letters of credit outstanding. Upon the closing of the Merger, the ENLK Credit Facility was canceled, and all indebtedness outstanding thereunder was repaid with cash on hand and proceeds of the Consolidated Credit Facility. We may use borrowings under the Consolidated Credit Facility to fund the operations and growth capital expenditures of ENLK through an intercompany arrangement with ENLC. Interest charged to ENLK for borrowings made through the intercompany arrangement will be substantially the same as interest charged to ENLC on the borrowings under the Consolidated Credit Facility.

In December 2018, we entered into the Term Loan and used the net proceeds to repay borrowings under the ENLK Credit Facility. At the closing of the Merger, the Term Loan was assumed by ENLC and we became a guarantor of the Term Loan. See "Item 8. Financial Statements— Note 18—Subsequent Events" for more information on the Merger and related transactions.

In addition, as of December 31, 2018, we have $3.5 billion in aggregate principal amount of outstanding unsecured senior notes with $400.0 million maturing in April 2019 and the remaining amount maturing from 2024 to 2047.

See "Item 8. Financial Statements—Note 6—Long-Term Debt" for more information on our outstanding debt instruments.

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 2016, 2017, and 2018. 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 and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation, and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see "Item 1. Business—Environmental Matters."

Contingencies

See "Item 8. Financial Statements and Supplementary Data—Note 13—Commitments and Contingencies."

Recent Accounting Pronouncements

See "Item 8. Financial Statements and Supplementary Data—Note 2—Significant Accounting Policies" for more information on recently issued and adopted accounting pronouncements.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Annual Report constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate," "expect," "continue," and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Annual Report, the risk factors set forth in "Item 1A. Risk Factors" may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events, or otherwise.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs, condensate, and crude oil. In addition, we are also exposed to the risk of changes in interest rates on floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the CFTC to regulate certain markets for derivative products, including OTC derivatives. The CFTC has issued several relevant regulations, and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not, and, as a result, the final form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC proposed and revised new rules in November 2013 and December 2016, respectively, that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC sought comment on the position limits rules as reproposed and revised, but the new rules have not yet been issued in final form, and the impact of any final provisions on us is uncertain at this time.

The legislation and potential new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Commodity Price Risk

The prices of crude oil, condensate, natural gas, and NGLs were volatile during 2018. Crude oil and weighted average NGL prices decreased 26% and 34%, respectively, while natural gas prices increased 19% from January 1, 2018 to December 31, 2018. We expect continued volatility in these commodity prices. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2018 ranged from a high of $76.41 per Bbl in October 2018 to a low of $42.53 per Bbl in December 2018. Weighted average NGL prices in 2018 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $0.93 per gallon in September 2018 to a low of

$0.46 per gallon in December 2018. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2018 ranged from a high of $4.84 per MMBtu in November 2018 to a low of $2.55 per MMBtu in February 2018.

Changes in commodity prices may indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, NGLs, crude oil, and condensate connected to or near our assets and on our fees earned for transportation between certain market centers. Low prices for these products could reduce the demand for our services and volumes in our systems. 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.

We are subject to risks due to fluctuations in commodity prices. Approximately 88% of our gross operating margin for the year ended December 31, 2018 was generated from arrangements with fee-based structures with minimal direct commodity price exposure. Our exposure to these commodity price fluctuations is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements (or a combination of these types of contractual arrangements) as summarized below.

1. *Fee-based contracts:* Under fee-based contracts, we earn our fees through (1) stated fixed-fee arrangements in which we are paid a fixed fee per unit of volume processed or (2) arrangements where we purchase and resell commodities in connection with providing the related processing service and earn a net margin through a fee-like deduction subtracted from the purchase price of the commodities.

2. *Processing margin contracts:* Under these contracts, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications. For the year ended December 31, 2018, approximately 1% of our contracts, based on gross operating margin, were under processing margin contracts.

3. *POL contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under POL contracts, but they do decline during periods of low liquids prices.

4. *POP contracts:* Under these contracts, we receive a fee in the form of a portion of the proceeds of the sale of natural gas and liquids. Therefore, our margins from these contracts are greater during periods of high natural gas and liquids prices. Our margins from processing cannot become negative under POP contracts, but they do decline during periods of low natural gas and liquids prices.

   For the year ended December 31, 2018, approximately 9% of our contracts, based on gross operating margin, were processed under POL or POP contracts.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas, crude and condensate, and NGLs using OTC derivative financial instruments with only certain well-capitalized counterparties which have been approved in accordance with our commodity risk management policy.

We have hedged our exposure to fluctuations in prices for natural gas, NGLs, crude oil, and condensate volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month-to-month processing options. Further, we have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon our expected equity NGL composition.

The following table sets forth certain information related to derivative instruments outstanding at December 31, 2018 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by Oil Price Information Service. The relevant index price for natural gas is Henry Hub Gas Daily as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume	We Pay	We Receive (1)	Fair Value Asset/(Liability) (In millions)
January 2019 - June 2019	Ethane	183 (MBbls)	$0.3048/gal	Index	$ 0.1
January 2019 - September 2019	Propane	479 (MBbls)	Index	$0.6370/gal	2.4
January 2019 - September 2019	Normal Butane	127 (MBbls)	Index	$0.7214/gal	0.8
January 2019 - September 2019	Natural Gasoline	85 (MBbls)	Index	$0.9602/gal	1.3
January 2019 - October 2019	Natural Gas	65,382 (MMBtu/d)	Index	$2.5946/MMBtu	(3.1)
January 2019 - December 2022	Crude and condensate	13,870 (MBbls)	Index	$52.09/bbl	7.0
					$ 8.5

(1) Weighted average.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of December 31, 2018, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, and other derivative instruments were a net fair value asset of $8.5 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas, crude and condensate, and NGL prices would result in a change of approximately $3.7 million in the net fair value of these contracts as of December 31, 2018.

Interest Rate Risk

At December 31, 2018, we were exposed to interest rate risk from the ENLK Credit Facility and the Term Loan entered into on December 11, 2018. At December 31, 2018, we had $850.0 million in outstanding borrowings under the Term Loan. A 1% increase or decrease in interest rates would change the annualized interest expense by approximately $8.5 million for the year. Following the close of the Merger, we are exposed to interest rate risk on the Consolidated Credit Facility and the Term Loan as guarantors of such indebtedness. See "Item 8. Financial Statements and Supplementary Data—Note 6—Long-Term Debt" for more information regarding our outstanding indebtedness.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2024, 2025, 2026, 2044, 2045, or 2047 as these are fixed-rate obligations. The estimated fair value of our senior unsecured notes was approximately $3,103.6 million as of December 31, 2018, based on market prices of similar debt at December 31, 2018. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in an approximate $210.7 million decrease in fair value of our senior unsecured notes at December 31, 2018.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

EnLink Midstream Partners, LP and Subsidiaries Financial Statements:

MANAGEMENT'S REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of EnLink Midstream GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for EnLink Midstream Partners, LP (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of EnLink Midstream GP, LLC's principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting is supported by written policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Partnership's transactions and dispositions of the Partnership's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the EnLink Midstream GP, LLC's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Partnership's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as ofDecember 31, 2018, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an attestation report on the Partnership's internal control over financial reporting, a copy of which appears on the following page of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Partners of EnLink Midstream Partners, LP and
The Board of Directors of EnLink Midstream GP, LLC:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of EnLink Midstream Partners, LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the "consolidated financial statements"). We also have audited the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Note 2(c) to the consolidated financial statements, the Partnership has changed its method of accounting for revenue recognition in 2018 due to the adoption of ASC 606*, Revenue from Contracts with Customers*.

Basis for Opinion

Management of EnLink Midstream GP, LLC, the general partner of EnLink Midstream Partners, LP, is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's consolidated financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

We have served as EnLink Midstream Partners, LP’s auditor since 2013.

Dallas, Texas
February 20, 2019

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Balance Sheets
(In millions, except unit data)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 99.5	$ 30.8
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3 and $0.3, respectively	126.3	50.1
Accrued revenue and other	705.9	576.6
Related party	2.1	102.7
Fair value of derivative assets	28.6	6.8
Natural gas and NGLs inventory, prepaid expenses, and other	72.8	39.7
Total current assets	1,035.2	806.7
Property and equipment, net of accumulated depreciation of $2,967.4 and $2,533.0, respectively	6,846.7	6,587.0
Intangible assets, net of accumulated amortization of $422.2 and $298.7, respectively	1,373.6	1,497.1
Goodwill	190.3	422.3
Investment in unconsolidated affiliates	80.1	89.4
Fair value of derivative assets	4.1	—
Other assets, net	41.3	11.5
Total assets	$ 9,571.3	$ 9,414.0
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 105.5	$ 66.9
Accounts payable to related party	4.3	18.4
Accrued gas, NGLs, condensate, and crude oil purchases	500.4	476.1
Fair value of derivative liabilities	21.8	8.4
Installment payable, net of discount of $0.5 at December 31, 2017	—	249.5
Current maturities of long-term debt	399.8	—
Other current liabilities	246.7	222.4
Total current liabilities	1,278.5	1,041.7
Long-term debt	3,919.8	3,467.8
Asset retirement obligations	14.8	14.2
Other long-term liabilities	20.0	33.9
Deferred tax liability	42.4	46.3
Fair value of derivative liabilities	2.4	—
Redeemable non-controlling interest	9.3	4.6
Partners' equity:		
Common unitholders (353,117,434 and 349,702,372 units issued and outstanding, respectively)	2,117.0	2,791.6
Series B preferred unitholders (58,728,994 and 57,056,281 units issued and outstanding, respectively)	889.3	864.1
Series C preferred unitholders (400,000 units outstanding)	395.1	395.1
General partner interest (1,594,974 equivalent units outstanding)	204.4	207.3
Accumulated other comprehensive loss	(2.1)	(2.1)
Non-controlling interest	680.4	549.5
Total partners' equity	4,284.1	4,805.5
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 9,571.3	$ 9,414.0

See accompanying notes to consolidated financial statements.

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ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Operations
(In millions, except per unit data)

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Product sales	$ 6,512.3	$ 4,358.4	$ 3,008.9
Product sales—related parties	41.0	144.9	134.3
Midstream services	763.3	552.3	467.2
Midstream services—related parties	377.2	688.2	653.1
Gain (loss) on derivative activity	5.2	(4.2)	(11.1)
Total revenues	7,699.0	5,739.6	4,252.4
Operating costs and expenses:			
Cost of sales (1)	6,008.0	4,361.5	3,015.5
Operating expenses	453.4	418.7	398.5
General and administrative	130.2	123.5	119.3
Loss on disposition of assets	0.4	—	13.2
Depreciation and amortization	577.3	545.3	503.9
Impairments	365.8	17.1	566.3
Gain on litigation settlement	—	(26.0)	—
Total operating costs and expenses	7,535.1	5,440.1	4,616.7
Operating income (loss)	163.9	299.5	(364.3)
Other income (expense):			
Interest expense, net of interest income	(178.3)	(187.9)	(188.1)
Gain on extinguishment of debt	—	9.0	—
Income (loss) from unconsolidated affiliates	13.3	9.6	(19.9)
Other income	0.6	0.6	0.3
Total other expense	(164.4)	(168.7)	(207.7)
Income (loss) before non-controlling interest and income taxes	(0.5)	130.8	(572.0)
Income tax benefit (provision)	2.1	24.0	(1.3)
Net income (loss)	1.6	154.8	(573.3)
Net income (loss) attributable to non-controlling interest	29.6	5.9	(8.1)
Net income (loss) attributable to ENLK	$ (28.0)	$ 148.9	$ (565.2)
General partner interest in net income	$ 38.6	$ 38.3	$ 39.5
Limited partners' interest in net income (loss) attributable to ENLK	$ (180.8)	$ 17.9	$ (662.1)
Class C partners' interest in net loss attributable to ENLK	$ —	$ —	$ (12.5)
Series B preferred interest in net income attributable to ENLK	$ 90.2	$ 86.0	$ 69.9
Series C preferred interest in net income attributable to ENLK	$ 24.0	$ 6.7	$ —
Net income (loss) attributable to ENLK per limited partners' unit:			
Basic common unit	$ (0.51)	$ 0.05	$ (1.99)
Diluted common unit	$ (0.51)	$ 0.05	$ (1.99)

(1) Includes related party cost of sales of $114.1 million, $211.0 million, and $150.1 million for the years ended December 31, 2018, 2017, and 2016, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
(In millions)

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$ 1.6	$ 154.8	$ (573.3)
Loss on designated cash flow hedge, net of amortization to interest expense	—	(2.1)	—
Comprehensive income (loss)	1.6	152.7	(573.3)
Comprehensive income (loss) attributable to non-controlling interest	29.6	5.9	(8.1)
Comprehensive income (loss) attributable to ENLK	$ (28.0)	$ 146.8	$ (565.2)

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Changes in Partners' Equity
(In millions)

	Common Units		Class C Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	Units	$	$	$	$
Balance, December 31, 2015	$ 4,055.8	325.2	$ 149.4	7.1	$ —	—	$ —	—	$ 213.4	1.6	$ —	$ 15.9	$ 4,434.5	$ 7.0
Issuance of common units	167.5	10.0	—	—	—	—	—	—	—	—	—	—	167.5	—
Issuance of Series B Preferred Units	—	—	—	—	724.1	50.0	—	—	—	—	—	—	724.1	—
Contribution from ENLC	—	—	—	—	—	—	—	—	—	—	—	237.1	237.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(1.2)	0.2	—	—	—	—	—	—	—	—	—	—	(1.2)	—
Unit-based compensation	15.1	—	—	—	—	—	—	—	14.9	—	—	—	30.0	—
Contribution from Devon	1.5	—	—	—	—	—	—	—	—	—	—	—	1.5	—
Distributions	(520.3)	—	—	0.4	—	3.2	—	—	(58.7)	—	—	(8.2)	(587.2)	(1.8)
Conversion of Class C Common Units to common units	136.9	7.5	(136.9)	(7.5)	—	—	—	—	—	—	—	—	—	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	—	—	207.4	207.4	—
Net income (loss)	(662.1)	—	(12.5)	—	69.9	—	—	—	39.5	—	—	(8.1)	(573.3)	—
Balance, December 31, 2016	$ 3,193.2	342.9	$ —	—	$ 794.0	53.2	$ —	—	$ 209.1	1.6	$ —	$ 444.1	$ 4,640.4	$ 5.2

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Changes in Partners' Equity (continued)
(In millions)

	Common Units		Class C Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	Units	$	$	$	$
Balance, December 31, 2016	$ 3,193.2	342.9	$ —	—	$ 794.0	53.2	$ —	—	$ 209.1	1.6	$ —	$ 444.1	$ 4,640.4	$ 5.2
Issuance of common units	106.9	6.2	—	—	—	—	—	—	—	—	—	—	106.9	—
Issuance of Series C Preferred Units	—	—	—	—	—	—	394.0	0.4	—	—	—	—	394.0	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.3)	0.6	—	—	—	—	—	—	—	—	—	—	(5.3)	—
Unit-based compensation	21.2	—	—	—	—	—	—	—	21.1	—	—	—	42.3	—
Contribution from Devon	1.3	—	—	—	—	—	—	—	—	—	—	—	1.3	—
Distributions	(543.6)	—	—	—	(15.9)	3.9	(5.6)	—	(61.2)	—	—	(26.9)	(653.2)	(0.6)
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	—	—	126.4	126.4	—
Unrealized loss on derivatives, net of amortization to interest expense	—	—	—	—	—	—	—	—	—	—	(2.1)	—	(2.1)	—
Net income	17.9	—	—	—	86.0	—	6.7	—	38.3	—	—	5.9	154.8	—
Balance, December 31, 2017	2,791.6	349.7	—	—	864.1	57.1	395.1	0.4	207.3	1.6	(2.1)	549.5	4,805.5	4.6
Issuance of common units	46.1	2.6	—	—	—	—	—	—	—	—	—	—	46.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.6)	0.8	—	—	—	—	—	—	—	—	—	—	(5.6)	—
Unit-based compensation	21.4	—	—	—	—	—	—	—	20.4	—	—	—	41.8	—
Distributions	(551.6)	—	—	—	(65.0)	1.6	(24.0)	—	(61.9)	—	—	(54.5)	(757.0)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	—	—	156.4	156.4	—
Fair value adjustment related to redeemable non-controlling interest	(4.1)	—	—	—	—	—	—	—	—	—	—	—	(4.1)	4.1
Net income (loss)	(180.8)	—	—	—	90.2	—	24.0	—	38.6	—	—	29.0	1.0	0.6
Balance, December 31, 2018	$ 2,117.0	353.1	$ —	—	$ 889.3	58.7	$ 395.1	0.4	$ 204.4	1.6	$ (2.1)	$ 680.4	$ 4,284.1	$ 9.3

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(In millions)

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$ 1.6	$ 154.8	$ (573.3)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments	365.8	17.1	566.3
Depreciation and amortization	577.3	545.3	503.9
Loss on disposition of assets	0.4	—	13.2
Non-cash unit-based compensation	40.8	47.8	30.0
Deferred tax benefit	(3.9)	(26.6)	(0.6)
(Gain) loss on derivatives recognized in net income (loss)	(5.2)	4.2	11.1
Cash settlements on derivatives	(7.0)	(11.2)	10.5
Gain on extinguishment of debt	—	(9.0)	—
Amortization of debt issue costs, net (premium) discount of notes and installment payable	4.0	29.1	53.1
Distribution of earnings from unconsolidated affiliates	15.8	13.3	3.1
(Income) loss from unconsolidated affiliates	(13.3)	(9.6)	19.9
Non-cash revenue from contract restructuring	(45.5)	—	—
Other operating activities	(2.6)	0.6	0.9
Changes in assets and liabilities, net of assets acquired and liabilities assumed:			
Accounts receivable, accrued revenue, and other	(114.6)	(189.5)	(117.9)
Natural gas and NGLs inventory, prepaid expenses, and other	(12.2)	(23.7)	10.2
Accounts payable, accrued gas and crude oil purchases, and other accrued liabilities	55.4	163.9	132.2
Net cash provided by operating activities	856.8	706.5	662.6
Cash flows from investing activities:			
Additions to property and equipment	(843.1)	(790.8)	(663.0)
Acquisition of business, net of cash acquired	—	—	(769.3)
Proceeds from sale of unconsolidated affiliate investment	—	189.7	—
Proceeds from sale of property	1.9	2.3	93.1
Investment in unconsolidated affiliates	(0.1)	(12.6)	(73.8)
Distribution from unconsolidated affiliates in excess of earnings	6.9	0.2	54.6
Other investing activities	8.1	0.4	0.3
Net cash used in investing activities	(826.3)	(610.8)	(1,358.1)
Cash flows from financing activities:			
Proceeds from borrowings	3,904.0	2,315.9	2,057.8
Payments on borrowings	(3,054.0)	(2,104.3)	(1,852.7)
Payment of installment payable for EOGP acquisition	(250.0)	(250.0)	—
Debt financing costs	(1.7)	(5.5)	(4.6)
Proceeds from issuance of common units	46.1	106.9	167.5
Proceeds from issuance of Series B Preferred Units	—	—	724.1
Proceeds from issuance of Series C Preferred Units	—	394.0	—
Distribution to common unitholders and to general partner	(613.5)	(604.8)	(579.0)
Distributions to Series B Preferred Unitholders	(65.0)	(15.9)	—
Distributions to Series C Preferred Unitholders	(24.0)	(5.6)	—
Distributions to non-controlling interests	(54.5)	(27.5)	(10.0)
Contributions by non-controlling interests, including contributions from affiliates of $66.2, $69.1, and $39.5, respectively	156.4	126.4	207.4
Other financing activities	(5.6)	(6.1)	(9.3)
Net cash provided by (used in) financing activities	38.2	(76.5)	701.2
Net increase in cash and cash equivalents	68.7	19.2	5.7
Cash and cash equivalents, beginning of period	30.8	11.6	5.9
Cash and cash equivalents, end of period	$ 99.5	$ 30.8	$ 11.6

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Organization of Business and Nature of Business

ENLK is a Delaware limited partnership formed in 2002. Our business activities are conducted through the Operating Partnership and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is a direct, wholly-owned subsidiary of ENLC as successor-in-interest to EMI, which merged with and into ENLC on December 31, 2018. ENLC's units are traded on the NYSE under the symbol "ENLC." ENLC's managing member is a wholly-owned subsidiary of GIP.

Effective as of March 7, 2014, the Operating Partnership acquired (the "Acquisition") 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. At the same time, EMI became a wholly-owned subsidiary of ENLC (together with the Acquisition, the "Business Combination"). In 2015, the Operating Partnership acquired the remaining 50% of the outstanding equity interests in Midstream Holdings.

EOGP Acquisition

On January 7, 2016, EOGP, an indirect subsidiary of ENLK, completed its acquisition of 100% of the issued and outstanding membership interests of TOMPC LLC and TOM-STACK, LLC. As a result of the acquisition, the Operating Partnership acquired an 83.9% limited partner interest in EOGP, and ENLC acquired the remaining 16.1% limited partner interest in EOGP. On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership in exchange for 55,827,221 ENLK common units, resulting in the Operating Partnership owning 100% of the limited partner interests in EOGP. See "Note 3—Acquisition" for further discussion.

GIP Transaction

On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP. As a result of the transaction:

- GIP, through GIP III Stetson I, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLK and the managing member of ENLC, which, as of the closing date, amounted to 100% of the outstanding limited liability company interests in the managing member of ENLC and approximately 23.1% of the outstanding limited partner interests in ENLK;
- GIP, through GIP III Stetson II, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLC, which, as of the closing date, amounted to approximately 63.8% of the outstanding limited liability company interests in ENLC; and
- Through this transaction, GIP acquired control of (i) the managing member of ENLC, (ii) ENLC, and (iii) ENLK, as a result of ENLC's ownership of ENLK's general partner.

Simplification of the Corporate Structure

On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. See "Note 18—Subsequent Events" for more information on the Merger and related transactions.

As a result of the Merger, ENLC owns all of our outstanding common units. ENLC also owns our general partner and has the power to appoint all of the officers and directors of our general partner. ENLC is managed by its managing member, which is wholly-owned by GIP. Therefore, GIP indirectly controls our general partner, which has the sole authority to manage and operate our business. Accordingly, through its control of our general partner, GIP effectively has the ability to control our management.

(b) Nature of Business

We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.9 Bcf/d of processing capacity, seven fractionators with approximately 280,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

Our natural gas business includes connecting the wells of producers in our market areas to our gathering systems. Our gathering systems consist of networks of pipelines that collect natural gas from points at or near producing wells and transport it to our processing plants or to larger pipelines for further transmission. We operate processing plants that remove NGLs from the natural gas stream that is transported to the processing plants by our own gathering systems or by third-party pipelines. In conjunction with our gathering and processing business, we may purchase natural gas and NGLs from producers and other supply sources and sell that natural gas or NGLs to utilities, industrial consumers, marketers, and pipelines. Our transmission pipelines 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.

Our fractionators separate NGLs into separate purity products, including ethane, propane, isobutane, normal butane, and natural gasoline. Our fractionators receive NGLs primarily through our transmission lines that transport NGLs from East Texas and from our South Louisiana processing plants. Our fractionators also have the capability to receive NGLs by truck or rail terminals. We also have agreements pursuant to which third parties transport NGLs from our West Texas and Central Oklahoma operations to our NGL transmission lines that then transport the NGLs to our fractionators. In addition, we have NGL storage capacity to provide storage for customers.

Our crude oil and condensate business includes the gathering and transmission of crude oil and condensate via pipelines, barges, rail, and trucks, in addition to condensate stabilization and brine disposal. We also purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities to various markets.

Across our businesses, we primarily earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodities purchased. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal.

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with GAAP for complete financial statements.

(b) Management's Use of Estimates

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

(c) Revenue Recognition

We generate the majority of our revenues from midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing, through various contractual arrangements, which include fee-based contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin for our fee. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Revenues from both "Product sales" and "Midstream services" represent revenues from contracts with customers and are reflected on the consolidated statements of operations as follows:

- *Product sales—P*roduct sales represent the sale of natural gas, NGLs, crude oil, and condensate where the product is purchased and resold in connection with providing our midstream services as outlined above.

- *Midstream services*—Midstream services represent all other revenue generated as a result of performing our midstream services outlined above.

Adoption of ASC 606

Effective January 1, 2018, we adopted ASC 606 using the modified retrospective method. ASC 606 replaces previous revenue recognition requirements in GAAP and requires entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 also requires significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.

Evaluation of Our Contractual Performance Obligations

In adopting ASC 606, we evaluated our contracts with customers that are within the scope of ASC 606. In accordance with the new revenue recognition framework introduced by ASC 606, we identified our performance obligations under our contracts with customers. These performance obligations include:

- promises to perform midstream services for our customers over a specified contractual term and/or for a specified volume of commodities; and

- promises to sell a specified volume of commodities to our customers.

The identification of performance obligations under our contracts requires a contract-by-contract evaluation of when control, including the economic benefit, of commodities transfers to and from us (if at all). This evaluation of control changed the way we account for certain transactions effective January 1, 2018, specifically those contracts in which there is both a commodity purchase and a midstream service. For contracts where control of commodities transfers to us before we perform our services, we generally have no performance obligation for our services, and accordingly, we do not consider these revenue-generating contracts for purposes of ASC 606. Based on the control determination, all contractually-stated fees that are deducted from our payments to producers or other suppliers for commodities purchased are reflected as a reduction in the cost of such commodity purchases. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating and recognize the fees received for satisfying them as midstream services revenues over time as we satisfy our performance obligations. For contracts where control of commodities never transfers to us and we simply earn a fee for our services, we recognize these fees as midstream services revenues over time as we satisfy our performance obligations.

We also evaluate our contractual arrangements that contain a purchase and sale of commodities under the principal/agent provisions in ASC 606. For contracts where we possess control of the commodity and act as principal in the purchase and sale, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as an agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract.

Based on our review of our performance obligations in our contracts with customers, we changed the consolidated statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. For the year ended December 31, 2018, the reclassification of revenues and cost of sales resulted in a net decrease in revenue of approximately $671.0 million or 8.0%, compared to total revenues based on accounting prior to the adoption of ASC 606, with an equivalent net decrease in cost of sales. The change in total revenues as a result of the adoption of ASC 606 is made up of the following revenue line item changes (in millions):

	Increase (Decrease) in Revenue Due to ASC 606 Adoption	
	Year Ended December 31, 2018	
Product sales	$	(235)
Product sales—related parties		(52)
Midstream services		(357)
Midstream services—related parties		(27)
Total	$	(671)

This change in accounting treatment had no impact on our operating income, net income, results of operations, financial condition, or cash flows.

Changes in Accounting Methodology for Certain Contracts

For NGL contracts in which we purchase raw mix NGLs and subsequently transport, fractionate, and market the NGLs, we accounted for these contracts prior to the adoption of ASC 606 as revenue-generating contracts in which the fees we earned for our services were recorded as midstream services revenue on the consolidated statements of operations. As a result of the adoption of ASC 606, we determined that the control, including the economic benefit, of commodities has passed to us once the raw mix NGLs have been purchased from the customer. Therefore, we now consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the raw mix NGLs, rather than being recorded as midstream services revenue. Upon sale of the NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

For our crude oil and condensate service contracts in which we purchase the commodity, we utilize a similar approach under ASC 606 as outlined above for NGL contracts. This treatment is consistent with our accounting for crude oil and condensate service contracts prior to the adoption of ASC 606.

For our natural gas gathering and processing contracts in which we perform midstream services and also purchase the natural gas, we accounted for these contracts prior to the adoption of ASC 606 as revenue-generating contracts in which all contractually-stated fees earned for our gathering and processing services were recorded as midstream services revenue on the statements of operations. As a result of the adoption of ASC 606, we must determine if economic control of the commodities has passed from the producer to us before or after we perform our services (if at all). Control is assessed on a contract-by-contract basis by analyzing each contract's provisions, which can include provisions for: the customer to take its residue gas and/or NGLs in-kind; fixed or actual NGL or keep-whole recovery; commodity purchase prices at weighted average sales price or market index-based pricing; and various other contract-specific considerations. Based on this control assessment, our gathering and processing contracts fall into two primary categories:

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas passes to us when the natural gas is brought into our system, we do not consider these contracts to contain performance obligations for our services. As control of the natural gas passes to us prior to performing our gathering and processing services, we are, in effect, performing our services for our own benefit. Based on this control determination, we consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the natural gas, rather than being recorded as midstream services revenue. Upon sale of the residue gas and/or NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas does not pass to us until after the natural gas has been gathered and processed, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenues over time as we satisfy our performance obligations.

For midstream service contracts related to NGL, crude oil, or natural gas gathering and processing in which there is no commodity purchase or control of the commodity never passes to us and we simply earn a fee for our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenue over time as we satisfy our performance obligations. This treatment is consistent with our accounting for these contracts prior to the adoption of ASC 606.

For our natural gas transmission contracts, we determined that control of the natural gas never transfers to us and we simply earn a fee for our services. Therefore, we recognize these fees as midstream services revenue over time as we satisfy our performance obligations. This treatment is consistent with our accounting for natural gas transmission contracts prior to the adoption of ASC 606.

We also evaluate our commodity marketing contracts, under which we purchase and sell commodities in connection with our gas, NGL, and crude and condensate midstream services, pursuant to ASC 606, including the principal/agent provisions. For contracts in which we possess control of the commodity and act as principal in the purchase and sale of commodities, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract. This treatment is consistent with our accounting for our commodity marketing contracts prior to the adoption of ASC 606.

Satisfaction of Performance Obligations and Recognition of Revenue

While ASC 606 alters the line item on which certain amounts are recorded on the consolidated statements of operations, ASC 606 did not significantly affect the timing of income and expense recognition on the consolidated statements of operations. Specifically, for our commodity sales contracts, we satisfy our performance obligations at the point in time at which the commodity transfers from us to the customer. This transfer pattern aligns with our billing methodology. Therefore, we recognize product sales revenue at the time the commodity is delivered and in the amount to which we have the right to invoice the customer, which is consistent with our accounting prior to the adoption of ASC 606. For our midstream service contracts that contain revenue-generating performance obligations, we satisfy our performance obligations over time as we perform the midstream service and as the customer receives the benefit of these services over the term of the contract. As permitted by ASC 606, we are utilizing the practical expedient that allows an entity to recognize revenue in the amount to which the entity has a right to invoice, since we have a right to consideration from our customer in an amount that corresponds directly with the value to the customer of our performance completed to date. Accordingly, we continue to recognize revenue over time as our midstream services are performed. Therefore, ASC 606 does not significantly affect the timing of revenue and expense recognition on our consolidated statements of operations, and no cumulative effect adjustment was made to the balance of equity upon our adoption of ASC 606.

We generally accrue one month of sales and the related natural gas, NGL, condensate, and crude oil purchases and reverse these accruals when the sales and purchases are invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. We typically receive payment for invoiced amounts within one month, depending on the terms of the contract. We account for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

Minimum Volume Commitments and Firm Transportation Contracts

Certain gathering and processing agreements in our Texas, Oklahoma, and Crude and Condensate segments provide for quarterly or annual MVCs, including MVCs from Devon from certain of our Barnett Shale assets in North Texas and our Cana gathering and processing assets in Oklahoma. Under these agreements, our customers or suppliers (as “customers” and “suppliers” are determined per application of ASC 606) agree to ship and/or process a minimum volume of product on our systems over an agreed time period. If a customer or supplier under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual product volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer or supplier to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in subsequent periods. Deficiency fee revenue is included in midstream services revenue.

For our firm transportation contracts, we transport commodities owned by others for a stated monthly fee for a specified monthly quantity with an additional fee based on actual volumes. We include transportation fees from firm transportation contracts in our midstream services revenue.

The following table summarizes the expected impact to our consolidated statements of operations, resulting from either revenue or reductions to cost of sales, from MVC and firm transportation contractual provisions. All amounts in the table below reflect the contractually-stated MVC or firm transportation volumes specified for each period multiplied by the relevant deficiency or reservation fee. Actual amounts could differ due to the timing of revenue recognition or reductions to cost of sales resulting from make-up right provisions included in our agreements, as well as due to nonpayment or nonperformance by our customers. In addition, amounts in the table below do not represent the shortfall amounts we expect to collect under our MVC contracts as we generally do not expect volume shortfalls to equal the full amount of the contractual MVCs during these periods.

2019	$ 252.1
2020	247.9
2021	104.5
2022	95.0
2023	92.9
Thereafter	281.9
Total	$ 1,074.3

In May 2018, we restructured one of our natural gas gathering and processing contracts that included MVCs that were in effect through 2023. Prior to the contract restructuring, we expected $135.1 million in guaranteed future gross operating margin under the contract, generated from either revenue or reductions to cost of sales resulting from both gathering and processing fees as well as shortfall revenue under the MVCs. As a result of the contract restructuring, all MVC provisions were removed from the contract, and we and the counterparty entered into additional agreements pursuant to which: (i) the counterparty made a $19.7 million payment to us on the date of the contract restructuring to satisfy MVC revenue earned up to the date of the contract restructuring; (ii) the counterparty entered into a second lien secured term loan under which the counterparty will pay us $58.0 million in principal payments in various installments ending in May 2023, with interest accruing on the loan balance at 8.0% per annum beginning in 2020; and (iii) the counterparty granted to us a 1.0% term overriding royalty interest through June 2034 in each well located on leasehold interests of the counterparty and connected to the gas gathering system that we operate. As a result of the contract restructuring and in accordance with ASC 606, we recognized $45.5 million of midstream services revenue, which primarily represents the discounted present value of the second lien secured term loan receivable, in the Oklahoma segment in the second quarter of 2018. Pursuant to the contract restructuring, the terms of the restructured contract, other than the MVCs, are the same as the original contract, and we expect to continue recognizing gathering and processing fees on volumes delivered by the customer

Contributions in Aid of Construction

The adoption of ASC 606 also alters how we account for contributions in aid of construction ("CIAC"). CIAC payments are lump sum payments from third parties to reimburse us for capital expenditures related to the construction of our operating assets and, in most cases, the connection of these operating assets to the third party's assets. CIAC payments can be paid to us prior to the commencement of construction activities, during construction, or after construction has been completed. Prior to adoption of ASC 606 and in accordance with ASC 980, *Regulated Operations* ("ASC 980"), and the FERC Uniform System of Accounts, we reduced the balance of the related property and equipment by the amount of CIAC payments received. In doing so, CIAC payments previously affected the consolidated statements of operations through reduced depreciation expense over the useful lives of the related property and equipment. Upon adoption of ASC 606, we initially recognize CIAC payments received from customers as deferred revenue, which will be subsequently amortized into revenue over the term of the underlying operational contract. For CIAC payments from noncustomers and for payments related to the construction of regulated operating assets, we continue to reduce the balance of the related property and equipment in accordance with ASC 980 and the FERC Uniform System of Accounts. This change in our CIAC accounting policy was not material to our financial statements for the year ended December 31, 2018.

Disaggregation of Revenue and Presentation of Prior Periods

Based on the disclosure requirements of ASC 606, we are presenting revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues. See "Note 14—Segment Information" for the revenue disaggregation information included in the segment information table for the year ended December 31, 2018. As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the year ended December 31, 2018 are presented to conform to ASC 606 accounting and disclosure requirements. Prior periods presented in the consolidated financial statements and accompanying notes were not restated in accordance with ASC 606.

(d) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. We had imbalance payables of $12.4 million and $7.3 million at December 31, 2018 and 2017, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of $10.4 million and $5.8 million at December 31, 2018 and 2017, respectively, which are carried at the lower of cost or market value. Imbalance receivables and imbalance payables are included in the line items "Accrued revenue and other" and "Accrued gas, NGLs, condensate and crude oil purchases," respectively, on the consolidated balance sheets.

(e) Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(f) Income Taxes

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

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

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

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

(h) Property and Equipment

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

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

	Year Ended December 31,	
	2018	2017
Transmission assets	$ 1,329.4	$ 1,338.7
Gathering systems	4,410.5	4,040.9
Gas processing plants	3,590.5	3,401.8
Other property and equipment	171.7	157.8
Construction in process	312.0	180.8
Property and equipment	9,814.1	9,120.0
Accumulated depreciation	(2,967.4)	(2,533.0)
Property and equipment, net of accumulated depreciation	$ 6,846.7	$ 6,587.0

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 $453.8 million, $418.2 million, and $386.9 million was recorded for the years ended December 31, 2018, 2017, and 2016, respectively.

Gain or Loss on Disposition. Upon the disposition or retirement of property and equipment, any gain or loss is recognized in operating income in the statement of operations. For the year ended December 31, 2018, we disposed of assets with a net book value of $2.1 million. These dispositions primarily related to vehicle retirements and retirements due to compressor fire damage. This decrease in book value was offset by $1.7 million of proceeds from the sale of property, resulting in $0.4 million loss on disposition of assets in the consolidated statement of operations for the year ended December 31, 2018.

For the year ended December 31, 2017, we disposed of assets with a net book value of $8.4 million, and these dispositions primarily related to the retirement of compressors due to fire damage. This decrease in book value was offset by $6.1 million in expected insurance settlements and $2.3 million of proceeds from the sale of property, resulting in no gain or loss on disposition of assets in the consolidated statement of operations for the year ended December 31, 2017.

For the year ended December 31, 2016, we retired or sold net property and equipment of $106.6 million, which was offset by $0.3 million of insurance settlements and $93.1 million of proceeds from the sale of property, resulting in a loss on disposition of assets of $13.2 million. The loss on disposition of assets primarily related to the sale of the NPTL, a 140-mile natural gas transportation pipeline in North Texas, that resulted in net proceeds of $84.6 million and a loss on sale of $13.4 million.

Impairment Review. In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets of identifiable business activities for potential impairment annually in the fourth quarter, and whenever events or changes in circumstances indicate that their carrying value 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 is recognized equal to the excess of the asset's carrying value over its fair value, which is based on inputs that are not observable in the market, and thus represent Level 3 inputs.

When determining whether impairment 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 future fee-based rate of new business or contract renewals;
- the purchase and resale margins on natural gas, NGLs, crude oil, and condensate;
- the volume of natural gas, NGLs, crude oil, and condensate available to the asset;
- markets available to the asset;
- operating expenses; and
- future natural gas, NGLs, crude oil, and condensate prices.

The amount of availability of natural gas, NGLs, crude oil, and condensate to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, crude oil, and condensate prices. Projections of natural gas, NGL, crude oil, and condensate 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.

For the year ended December 31, 2018, we determined that the undiscounted cash flows for two of our assets were not in excess of their carrying values. We estimated the fair values of these assets and determined that their fair values were not in excess of their carrying values, which resulted in impairments on property and equipment of $24.6 million related to certain non-core natural gas pipeline assets in the Louisiana segment and $109.2 million related to non-core crude pipeline assets in the Crude and Condensate segment.

For the year ended December 31, 2017, we recognized a $17.1 million impairment on property and equipment, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well. There were no impairments on property and equipment recognized for the year ended December 31, 2016.

(i) Comprehensive Income (Loss)

Comprehensive income (loss) is composed of net income (loss), which consists of the effective portion of gains or losses on derivative financial instruments that qualify as cash flow hedges pursuant to ASC 815, *Derivatives and Hedging* ("ASC 815"). For the year ended December 31, 2018 and 2017, we reclassified an immaterial amount of losses from accumulated other comprehensive income (loss) to earnings. For additional information, see "Note 11—Derivatives."

(j) Equity Method of Accounting

We account for investments where we do not control the investment but have the ability to exercise significant influence using the equity method of accounting. Under this method, unconsolidated affiliate investments are initially carried at the acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received.

We evaluate our unconsolidated affiliate investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable. We recognize impairments of our investments as a loss from unconsolidated affiliates on our consolidated statements of operations. For additional information, see "Note 9—Investment in Unconsolidated Affiliates."

(k) Non-controlling Interests

We account for investments where we control the investment using the consolidation method of accounting. Under this method, we consolidate all the assets and liabilities of an investment on our consolidated balance sheets and record non-controlling interest for the portion of the investment that we do not own. We include all of an investment's results of operations on our consolidated statements of operations and record income attributable to non-controlling interests for the portion of the investment that we do not own.

Our non-controlling interests for the years ended December 31, 2018, 2017, and 2016 relate to ENLC's 16.1% ownership of EOGP, NGP's 49.9% ownership of the Delaware Basin JV, Marathon Petroleum Corporation's 50.0% ownership interest in the Ascension JV, and other minor non-controlling interests.

(l) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. For additional information regarding our assessment of goodwill for impairment, see "Note 4—Goodwill and Intangible Assets."

(m) 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 five to twenty years. For additional information regarding our intangible assets, including our assessment of intangible assets for impairment, see "Note 4—Goodwill and Intangible Assets."

(n) Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with our pipelines and processing and fractionation facilities. Such liabilities are recognized when there is a legal obligation associated with the retirement of the assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Our retirement obligations include estimated environmental remediation costs that 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 and equipment.

(o) Other Long-Term Liabilities

Other current and long-term liabilities include a liability related to an onerous performance obligation assumed in the Business Combination of $9.0 million and $26.9 million as of December 31, 2018 and 2017, respectively. We have one delivery contract that requires us to deliver a specified volume of gas each month at an indexed base price with a term to mid-2019. We realize a loss on the delivery of gas under this contract each month based on current prices. The fair value of this onerous performance obligation was based on forecasted discounted cash obligations in excess of market under this gas delivery contract in March 2014. The liability is reduced each month as delivery is made over the remaining life of the contract with an offsetting reduction in purchased gas costs.

(p) Derivatives

We use derivative instruments to hedge against changes in cash flows related to product price. 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 at the fair value of derivative assets or liabilities in accordance with ASC 815, *Derivatives and Hedging* ("ASC 815"). Changes in fair value of derivative instruments are recorded in gain or 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 statements of operations in the period incurred. Settlements of derivatives are included in cash flows from operating activities.

We periodically enter into interest rate swaps in connection with new debt issuances. During the debt issuance process, we are exposed to variability in future long-term debt interest payments that may result from changes in the benchmark interest rate (commonly the U.S. Treasury yield) prior to the debt being issued. In order to hedge this variability, we enter into interest rate swaps to effectively lock in the benchmark interest rate at the inception of the swap. Prior to 2017, we did not designate interest rate swaps as hedges and, therefore, included the associated settlement gains and losses as interest expense on the consolidated statements of operations.

In May 2017, we entered into an interest rate swap in connection with the issuance of our 2047 Notes. In accordance with ASC 815, we designated this swap as a cash flow hedge. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated comprehensive loss on the consolidated balance sheets. We will amortize the settlement loss into interest expense on the consolidated statements of operations over the term of the 2047 Notes. For additional information, see "Note 11—Derivatives."

(q) Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade accounts receivable and commodity financial instruments. Management believes the risk is limited, other than our exposure to significant customers discussed below, since our customers represent a broad and diverse group of energy marketers and end users. In addition, we continually monitor and review the credit exposure of our marketing counter-parties, and letters of credit or other appropriate security are obtained when considered necessary to limit the risk of loss. We record reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. We had a reserve for uncollectible receivables of $0.3 million and $0.3 million as of December 31, 2018 and 2017, respectively.

The following customers individually represented greater than 10% of our consolidated revenues. These customers represent a significant percentage of revenues, and the loss of the customer would have a material adverse impact on our results of operations because the revenues and gross operating margin received from transactions with these customers is material to us. No other customers represented greater than 10% of our consolidated revenues.

	Year Ended December 31,		
	2018	2017	2016
Devon	10.4%	14.4%	18.5%
Dow Hydrocarbons and Resources LLC	11.1%	11.2%	10.8%
Marathon Petroleum Corporation	11.5%	(1)	(1)

(1) Consolidated revenues for Marathon Petroleum Corporation did not exceed 10% of our consolidated revenues for the years ended December 31, 2017 and 2016.

(r) 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 years ended December 31, 2018, 2017, and 2016, environmental expenditures were not material.

(s) Unit-Based Awards

We recognize compensation cost related to all unit-based awards in our consolidated financial statements in accordance with ASC 718, *Compensation—Stock Compensation* ("ASC 718"). We and ENLC each have similar unit-based payment plans for employees. Unit-based compensation associated with ENLC's unit-based compensation plans awarded to directors, officers, and employees of our general partner are recorded by us since ENLC has no substantial or managed operating activities other than its interests in us. For additional information, see "Note 10—Employee Incentive Plans."

(t) 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. For additional information, see "Note 13—Commitments and Contingencies."

(u) Debt Issuance Costs

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 $24.3 million and $25.9 million as of December 31, 2018 and 2017, respectively, are included in "Long-term debt" or "Current maturities of long-term debt," as applicable, on the consolidated balance sheets as a direct reduction from the carrying amount of the debt. Debt issuance costs are amortized into interest expense using the straight-line method over the term of the related debt issuance.

(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.

(w) Redeemable Non-Controlling Interest

Non-controlling interests that contain an option for the non-controlling interest holder to require us to buy out such interests for cash are considered to be redeemable non-controlling interests because the redemption feature is not deemed to be a freestanding financial instrument and because the redemption is not solely within our control. Redeemable non-controlling interest is not considered to be a component of partners' equity and is reported as temporary equity in the mezzanine section on the consolidated balance sheets. The amount recorded as redeemable non-controlling interest at each balance sheet date is the greater of the redemption value and the carrying value of the redeemable non-controlling interest (the initial carrying value increased or decreased for the non-controlling interest holder's share of net income or loss and distributions).

(x) Adopted Accounting Standards

Effective January 1, 2018, we adopted ASC 606 using the modified retrospective method. ASC 606 replaces previous revenue recognition requirements in GAAP and requires entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 also requires significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. For additional information about our application of ASC 606 refer to "(c) Revenue Recognition" above.

(y) Accounting Standards to be Adopted in Future Periods

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)—Amendments to the FASB Accounting Standards Codification* ("ASU 2016-02"), which establishes ASC Topic 842, *Leases* ("ASC 842"). Under ASC 842, lessees will need to recognize virtually all of their leases on the balance sheet by recording a right-of-use asset and lease liability. Lessor accounting is similar to the current model but updated to align with certain changes to the lessee model and the new revenue recognition standard. Existing sale-leaseback guidance is replaced with a new model applicable to both lessees and lessors. Additional revisions have been made to embedded leases, reassessment requirements, and lease term assessments including variable lease payment, discount rate, and lease incentives. ASC 842 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those annual periods. We will adopt ASC 842 effective January 1, 2019. We have assessed the impact of adopting ASC 842 and implemented a lease accounting software. This assessment includes the evaluation of our current lease contracts and the analysis of contracts that may contain lease components. We are electing to apply certain practical expedients that are allowed in the adoption of ASC 842, including not reassessing existing contracts for lease arrangements, not reassessing existing lease classification, not recording a right-of-use asset or lease liability for leases of twelve months or less, and not separating lease and non-lease components of a lease arrangement. We believe the adoption of ASC 842 will increase our asset and liability balances on the consolidated balance sheets by approximately $75 million due to the required recognition of right-of-use assets and corresponding lease liabilities for all lease obligations that are currently classified as operating leases.

In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842)—Land Easement Practical Expedient for Transition to Topic 842* (“ASU 2018-01”). ASU 2018-01 amends ASC 842 and provides an optional practical expedient to not evaluate under ASC 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in ASC 840, *Leases*. Under ASU 2018-01, an entity that elects this practical expedient should evaluate new or modified land easements under ASC 842 beginning at the date that the entity adopts ASC 842. We plan to utilize the practical expedient provided in ASU 2018-01 in conjunction with our adoption of ASC 842.

In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842)—Targeted Improvements* (“ASU 2018-11”). ASU 2018-11 amends ASC 842 and allows entities to adopt the new leases standard using a modified retrospective approach. Under this new transition method, entities initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Additionally, an entity’s reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with current GAAP. We plan to utilize the optional transition method provided in ASU 2018-11 in conjunction with our adoption of ASC 842 in January 2019.

(3) Acquisition

On January 7, 2016, ENLK and ENLC acquired an 83.9% and 16.1% voting interest, respectively, in EOGP for aggregate consideration of approximately $1.4 billion. Upon closing of the acquisition on January 7, 2016, the first installment of $1.02 billion for the acquisition was paid. The second and final installments, each equal to $250.0 million, were paid in January 2017 and January 2018, respectively.

The first installment of approximately $1.02 billion was funded by (a) approximately $783.6 million in cash paid by ENLK, which was primarily derived from the issuance of Series B Preferred Units, (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and (c) approximately $22.2 million in cash paid by ENLC. The transaction was accounted for using the acquisition method.

The following table presents the considerations ENLK and ENLC paid and the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration:		
Cash	$	783.6
Total installment payable, net of discount of $79.1 million		420.9
Contribution from ENLC		237.1
Total consideration	$	1,441.6
Purchase Price Allocation:		
Assets acquired:		
Current assets (including $12.8 million in cash)	$	23.0
Property and equipment		406.1
Intangibles		1,051.3
Liabilities assumed:		
Current liabilities		(38.8)
Total identifiable net assets	$	1,441.6

The fair value of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. We recognized intangible assets related to customer relationships and determined their fair value using the income approach. The acquired intangible assets are amortized on a straight-line basis over the estimated customer life of approximately 15 years.

We incurred a total of $3.7 million of direct transaction costs for the year ended December 31, 2016. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from January 7, 2016 to December 31, 2016, we recognized $246.1 million of revenues and $34.1 million of net loss, of which $5.5 million is attributable to non-controlling interests, related to the assets acquired.

(4) Goodwill and Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business.The fair value of goodwill is based on inputs that are not observable in the market and thus represent Level 3 inputs.

The table below provides a summary of our change in carrying amount of goodwill (in millions) for the year ended December 31, 2018, by assigned reporting unit. For the year ended December 31, 2017, there were no changes to the carrying amounts of goodwill.

	Texas	Oklahoma	Totals
Year Ended December 31, 2018			
Balance, beginning of period	$ 232.0	$ 190.3	$ 422.3
Impairment	(232.0)	—	(232.0)
Balance, end of period	$ —	$ 190.3	$ 190.3

We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform a goodwill impairment test. We may elect to perform a goodwill impairment test without completing a qualitative assessment.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows, including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors. Impairment determinations involve significant assumptions and judgments, and differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. The estimated fair value of our reporting units may be impacted in the future by a decline in our unit price or a prolonged period of lower commodity prices which may adversely affect our estimate of future cash flows, both of which could result in future goodwill impairment charges for our reporting units.

Prior to January 2017, if a goodwill impairment test was elected or required, we performed a two-step goodwill impairment test. The first step involved comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeded its fair value, the second step of the process involved 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 exceeded the implied fair value of that goodwill, the excess of the carrying value over the implied fair value was recognized as an impairment.

Effective January 2017, we elected to early adopt ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)— Simplifying the Test for Goodwill Impairment* "ASU 2017-04"), which simplified the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in ASC 350, *Intangibles—Goodwill and Other*. Therefore, our annual impairment test as of October 31, 2017 was performed according to ASU 2017-04.

Goodwill Impairment Analysis for the Year Ended December 31, 2018

During our annual goodwill impairment test for 2018, which was performed as of October 31, 2018, we determined, based upon our qualitative assessment, that no impairments of goodwill were required as of that date. However, subsequent to October 31, 2018, we determined that due to a significant decline in our unit price, a change in circumstances had occurred that warranted a quantitative impairment test. Based on this triggering event, we performed a quantitative goodwill impairment analysis as of December 31, 2018. Based on this analysis, a goodwill impairment loss for our Texas reporting unit in the amount of $232.0 million was recognized in the fourth quarter of 2018 and is included in impairments in the consolidated statement of operations for the year ended December 31, 2018. Substantially all of the goodwill for our Texas reporting unit was recorded as a result of our Business Combination in March 2014.

We concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded for the Oklahoma reporting unit as a result of our quantitative impairment test.

Goodwill Impairment Analysis for the Year Ended December 31, 2017

During our annual impairment test for 2017, performed as of October 31, 2017, we determined that no impairments were required for the year ended December 31, 2017.

Goodwill Impairment Analysis for the Year Ended December 31, 2016

During February 2016, we determined that continued weakness in the overall energy sector, driven by low commodity prices together with a decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as impairments in the consolidated statement of operations for the year ended December 31, 2016.

We concluded that the fair value of our Oklahomareporting unit exceeded its carrying value,and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded forthis reporting unit as a result of our goodwill impairment analysis.

During our annual impairment test for 2016, performed as of October 31, 2016, we determined that no further impairments were required for the year ended December 31, 2016.

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 5 to 20 years.

The following table represents our change in carrying value of intangible assets for the periods stated (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Year Ended December 31, 2018			
Customer relationships, beginning of period	$ 1,795.8	$ (298.7)	$ 1,497.1
Amortization expense	—	(123.5)	(123.5)
Customer relationships, end of period	$ 1,795.8	$ (422.2)	$ 1,373.6
Year Ended December 31, 2017			
Customer relationships, beginning of period	$ 1,795.8	$ (171.6)	$ 1,624.2
Amortization expense	—	(127.1)	(127.1)
Customer relationships, end of period	$ 1,795.8	$ (298.7)	$ 1,497.1
Year Ended December 31, 2016			
Customer relationships, beginning of period	$ 744.5	$ (54.6)	$ 689.9
Acquisitions	1,051.3	—	1,051.3
Amortization expense	—	(117.0)	(117.0)
Customer relationships, end of period	$ 1,795.8	$ (171.6)	$ 1,624.2

For the years ended December 31, 2018, 2017, and 2016, we reviewed our various assets groups for impairment during our annual impairment review process and determined that no impairment of our intangible assets occurred. We utilized Level 3 fair value measurements in our impairment analysis, which included discounted cash flow assumptions by management consistent with those utilized in our goodwill impairment analysis.

The weighted average amortization period for intangible assets is 15.0 years. Amortization expense was $123.5 million, $127.1 million, and $117.0 million for the years ended December 31, 2018, 2017, and 2016, respectively.

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

2019	$ 123.7
2020	123.7
2021	123.7
2022	123.7
2023	123.6
Thereafter	755.2
Total	$ 1,373.6

(5) Related Party Transactions

Simplification of the Corporate Structure

On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. See "Note 18—Subsequent Events" for more information on the Merger and related transactions.

Transactions with Devon

On July 18, 2018, subsidiaries of Devon sold all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP for aggregate consideration of $3.125 billion. Accordingly, Devon is no longer an affiliate of ENLK or ENLC. The sale did not affect our commercial arrangements with Devon, except that Devon agreed to extend through 2029 certain existing fixed-fee gathering and processing contracts related to the Bridgeport plant in North Texas and the Cana plant in Oklahoma. See "Note 1—Organization and Summary of Significant Agreements" for additional information regarding the GIP Transaction. Prior to July 18, 2018, revenues from transactions with Devon are included in "Product sales—related parties" or "Midstream services—related parties" in the consolidated statement of operations. Revenues from transactions with Devon after July 18, 2018 are included in "Product sales" or "Midstream services" in the consolidated statement of operations.

For the years ended December 31, 2018, 2017, and 2016, related party transactions with Devon accounted for 5.4%, 14.4%, and 18.5% of our revenues, respectively. We had an accounts receivable balance related to transactions with Devon of $102.7 million as of December 31, 2017. Additionally, we had an accounts payable balance related to transactions with Devon of $16.3 million as of December 31, 2017. Management believes these transactions are executed on terms that are fair and reasonable. The amounts from related party transactions are specified in the accompanying consolidated financial statements.

Gathering, Processing, and Transportation Agreements Associated with Our Business Combination with Devon

As described in "Note 1—Organization and Summary of Significant Agreements," Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. On January 1, 2014, in connection with the consummation of the Business Combination, EnLink Midstream Services, LLC, a wholly-owned subsidiary of Midstream Holdings ("EnLink Midstream Services"), entered into 10-year gathering and processing agreements with Devon pursuant to which EnLink Midstream Services provides gathering, treating, compression, dehydration, stabilization, processing, and fractionation services, as applicable, for natural gas delivered by Devon Gas Services, L.P., a subsidiary of Devon ("Gas Services"), to Midstream Holdings' gathering and processing systems in the Barnett, Cana-Woodford, and Arkoma-Woodford Shales. On January 1, 2014, SWG Pipeline, L.L.C. ("SWG Pipeline"), another wholly-owned subsidiary of Midstream Holdings, entered into a 10-year gathering agreement with Devon pursuant to which SWG Pipeline provides gathering, treating, compression, dehydration, and redelivery services, as applicable, for natural gas delivered by Gas Services to another of our gathering systems in the Barnett Shale.

These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas, and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. Pursuant to the gathering and processing agreements entered into on January 1, 2014, Devon has committed to deliver specified minimum daily volumes of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford, and Arkoma-Woodford Shales during each calendar quarter. From January 1, 2018 to July 18, 2018, we recognized $321.3 million of revenue under these agreements. For the years ended December 31, 2017 and 2016, we recognized $615.5 million and $611.8 million of revenue, respectively, under these agreements. Included in these amounts of revenue recognized is revenue from MVCs attributable to Devon of $50.8 million from January 1, 2018 to July 18, 2018 and $81.9 million and $46.2 million for the years ended December 31, 2017 and 2016, respectively. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

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

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

EOGP Agreement with Devon

In January 2016, in connection with the acquisition of EOGP, we acquired a gas gathering and processing agreement with Devon Energy Production Company, L.P. ("DEPC") pursuant to which EOGP provides gathering, treating, compression, dehydration, stabilization, processing, and fractionation services, as applicable, for natural gas delivered by DEPC. The agreement has an MVC that will remain in place during each calendar quarter for four years and an overall term of approximately 15 years. Additionally, the agreement provides EOGP with dedication of all of the natural gas owned or controlled by DEPC 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 DEPC. DEPC is entitled to firm service, meaning a level of gathering and processing service in which DEPC's reserved capacity may not be interrupted, except due to force majeure, and may not be displaced by another customer or class of service. This agreement accounted for approximately $77.6 million, $100.4 million, and $34.4 million of our combined revenues from January 1, 2018 to July 18, 2018 and for the years ended December 31, 2017 and 2016, respectively.

Other Commercial Relationships with Devon

As noted above, we continue to maintain a customer relationship with Devon originally established prior to the Business Combination pursuant to which we provide gathering, transportation, processing, and gas lift services to Devon in exchange for fee-based compensation under several agreements with Devon. In addition, we have agreements with Devon pursuant to which we purchase and sell NGLs, gas, and crude oil and pay or receive, as applicable, a margin-based fee. These NGL, gas, and crude oil purchase and sale agreements have month-to-month terms. These historical agreements collectively comprise $66.6 million, $78.0 million, and $107.2 million of our combined revenue from January 1, 2018 to July 18, 2018 and for the years ended December 31, 2017 and 2016, respectively.

VEX Transportation Agreement

In connection with our acquisition of the VEX assets from Devon, we became party to a five-year transportation services agreement with Devon pursuant to which we provide transportation services to Devon on the VEX pipeline. This agreement includes a five-year MVC with Devon. The MVC was executed in June 2014, and the initial term expires July 2019. This agreement accounted for approximately $3.5 million, $17.8 million, and $18.7 million of service revenues from January 1, 2018 to July 18, 2018 and for the years ended December 31, 2017 and 2016, respectively.

Acacia Transportation Agreement

In connection with the consummation of the Business Combination, we entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which we provide transportation services to Devon on our Acacia pipeline in Texas. This agreement accounted for approximately $4.9 million, $13.8 million, and $15.2 million of our combined revenues from January 1, 2018 to July 18, 2018 and for the years ended December 31, 2017 and 2016, respectively.

GCF Interest

In connection with the consummation of the Business Combination and the GIP Transaction, a wholly-owned subsidiary of Devon transferred to us its 38.75% general partner interest in GCF. Our interest in GCF contributed approximately $10.5 million, $12.6 million, and $3.4 million to our income from unconsolidated affiliate investment from January 1, 2018 to July 18, 2018 and for the years ended December 31, 2017 and 2016, respectively.

Cedar Cove Joint Venture

On November 9, 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma. Under a 15-year, fixed-fee agreement, all gas gathered by the Cedar Cove JV will be processed at our Central Oklahoma processing system. For the period from November 9, 2016 through December 31, 2016, revenue generated from processing gas and cost of sales from the Cedar Cove JV was immaterial. For the years ended December 31, 2018 and December 31, 2017, we recorded service revenue of $0.5 million and $5.4 million, respectively, that is recorded as "Midstream services—related parties" on the consolidated statements of operations. In addition, for the years ended December 31, 2018 and December 31, 2017, we recorded cost of sales of $44.1 million and $30.6 million, respectively, related to our purchase of residue gas and NGLs from the Cedar Cove JV subsequent to processing at our Central Oklahoma processing facilities. We had an accounts receivable balance related to transactions with the Cedar Cove JV of $0.7 million at December 31, 2018. Additionally, we had an accounts payable balance related to transactions with the Cedar Cove JV of $4.3 million at December 31, 2018. The accounts receivable and payable balances related to transactions with the Cedar Cove JV were immaterial at December 31, 2017.

Transactions with ENLC

ENLC paid us $2.5 million, $2.4 million, and $2.3 million as reimbursement during the years ended December 31, 2018, 2017, and 2016, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for ENLC. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for ENLC provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes, and other benefit costs) is allocated to ENLC for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support, and information service support.

ENLC paid us $26.6 million, $48.4 million, and $31.5 million for their interest in EOGP's capital expenditures for the years ended December 31, 2018, 2017, and 2016, respectively. ENLC paid its contribution for EOGP's capital expenditures to us monthly, net of EOGP's adjusted EBITDA distributable to ENLC, which is defined as earnings before depreciation and amortization and provision for income taxes and includes allocated expenses from us. Following the Merger, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership. See "Note 18—Subsequent Events" for more information regarding these transactions.

Tax Sharing Agreement

In connection with the consummation of the Business Combination, we, ENLC, and Devon, entered into a tax sharing agreement providing for the allocation of responsibilities, liabilities, and benefits relating to any tax for which a combined tax return is due. From January 1, 2018 to July 18, 2018 and the years ended December 31, 2017 and 2016 we incurred approximately $0.4 million, $1.2 million, and $2.3 million, respectively, in taxes that are subject to the tax sharing agreement. Effective July 18, 2018, ENLK, ENLC, and Devon signed a supplemental agreement to continue the tax sharing agreement.

(6) Long-Term Debt

As of December 31, 2018 and 2017, long-term debt consisted of the following (in millions):

	December 31, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
2.70% Senior unsecured notes due 2019 (1)	$ 400.0	$ —	$ 400.0	$ 400.0	$ (0.1)	$ 399.9
Term Loan due 2021 (2)	850.0	—	850.0	—	—	—
4.40% Senior unsecured notes due 2024	550.0	1.8	551.8	550.0	2.2	552.2
4.15% Senior unsecured notes due 2025	750.0	(0.9)	749.1	750.0	(1.0)	749.0
4.85% Senior unsecured notes due 2026	500.0	(0.5)	499.5	500.0	(0.6)	499.4
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(6.2)	443.8	450.0	(6.5)	443.5
5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt classified as long-term	$ 4,350.0	$ (6.1)	4,343.9	$ 3,500.0	$ (6.3)	3,493.7
Debt issuance cost (3)			(24.3)			(25.9)
Less: Current maturities of long-term debt (1)			(399.8)			—
Long-term debt, net of unamortized issuance cost			$ 3,919.8			$ 3,467.8

(1) The 2.70% senior unsecured notes mature on April 1, 2019. Therefore, the outstanding principal balance, net of discount and debt issuance costs, is classified as “Current maturities of long-term debt” on the consolidated balance sheet as of December 31, 2018.
(2) In December 2018, ENLK entered into an $850.0 million, three-year unsecured Term Loan. Borrowings under the Term Loan bear interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.9% at December 31, 2018.
(3) Net of amortization of $15.3 million and $12.0 million at December 31, 2018 and 2017, respectively.

Maturities

Maturities for the long-term debt as of December 31, 2018 are as follows (in millions):

2019	$ 400.0
2020	—
2021	850.0
2022	—
2023	—
Thereafter	3,100.0
Subtotal	4,350.0
Less: net discount	(6.1)
Less: debt issuance cost	(24.3)
Less: current maturities of long-term debt	(399.8)
Long-term debt, net of unamortized issuance cost	$ 3,919.8

ENLK Credit Facility

Prior to the closing of the Merger, we had a $1.5 billion unsecured revolving credit facility that matured on March 6, 2020, which included a $500.0 million letter of credit subfacility. Upon the closing of the Merger, the ENLK Credit Facility was repaid and canceled, and all indebtedness thereunder was repaid with borrowings under the Consolidated Credit Facility at ENLC.

Borrowings under the ENLK Credit Facility bore interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.00% to 1.75%) 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 (ranging from 0.0% to 0.75%). The applicable margins varied depending on our credit rating.

On June 20, 2018, we amended the change of control provisions of the ENLK Credit Facility to, among other things, designate GIP as Qualifying Owners (as defined in the ENLK Credit Facility).

As of December 31, 2018 and 2017, we had no borrowings under the ENLK Credit Facility, and there were $9.8 million in outstanding letters of credit for each period, respectively.

Consolidated Credit Facility

In connection with the Merger, we refinanced our existing revolving credit facilities at ENLK and ENLC. As of December 31, 2018, we had a $1.5 billion facility at ENLK and a $250.0 million facility at ENLC. Following the Merger, we have combined these credit facilities into one $1.75 billion credit facility at ENLC. Following the Merger, ENLK guaranteed the obligations of ENLC under the Consolidated Credit Facility. For additional information, refer to "Note 18—Subsequent Events."

At December 31, 2018, ENLC was in compliance with and expects to be in compliance with the covenants in the Consolidated Credit Facility for at least the next twelve months.

Term Loan

On December 11, 2018, ENLK entered into the Term Loan with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto.

Also, on December 11, 2018, ENLK borrowed $850.0 million under the Term Loan and used the net proceeds to repay obligations outstanding under the ENLK Credit Facility. Upon the closing of the Merger, ENLC assumed ENLK's obligations under the Term Loan, and ENLK became a guarantor of the Term Loan. The obligations under the Term Loan are unsecured.

The Term Loan will mature on December 10, 2021. The Term Loan contains certain financial, operational, and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenants include (i) maintaining a ratio of consolidated EBITDA (as defined in the Term Loan, which term includes projected EBITDA from certain capital expansion projects) to consolidated interest charges of no less than 2.50 to 1.0 at all times prior to the occurrence of an investment grade event (as defined in the Term Loan) and (ii) maintaining a ratio of consolidated indebtedness to consolidated EBITDA of no more than 5.00 to 1.00. If the borrower consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the borrower can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.50 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters.

Borrowings under the Term Loan bear interest at the borrower's option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.00% to 1.75%) 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 (ranging from 0.00% to 0.75%). The applicable margins vary depending on ENLC's debt rating. Upon breach by the borrower of certain covenants included in the Term Loan, amounts outstanding under the Term Loan may become due and payable immediately.

At December 31, 2018, ENLC was in compliance with and expects to be in compliance with the covenants of the Term Loan for at least the next twelve months.

Issuances and Redemptions of Senior Unsecured Notes

On March 7, 2014, we recorded $196.5 million in aggregate principal amount of 7.125% senior unsecured notes (the “2022 Notes”) due on June 1, 2022 in the Business Combination. The interest payments on the 2022 Notes were due semi-annually in arrears in June and December. As a result of the Business Combination, the 2022 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $226.0 million, including a premium of $29.5 million. On July 20, 2014, we redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, we redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. On June 1, 2017, we redeemed the remaining $162.5 million in aggregate principal amount of the 2022 Notes at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which resulted in a gain on extinguishment of debt of $9.0 million for the year ended December 31, 2017.

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

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

On May 12, 2015, we issued $900.0 million aggregate principal amount of unsecured senior notes, consisting of $750.0 million aggregate principal amount of our 4.150% senior notes due 2025 (the “2025 Notes”) and an additional $150.0 million aggregate principal amount of 2045 Notes at prices to the public of 99.827% and 96.381%, respectively, of their face value. The 2025 Notes mature on June 1, 2025. Interest payments on the 2025 Notes are due semi-annually in arrears in June and December. The new 2045 Notes were offered as an additional issue of our outstanding 2045 Notes issued on November 12, 2014. The 2045 Notes issued on November 12, 2014 and May 12, 2015 are treated as a single class of debt securities and have identical terms, other than the issue date.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the “2026 Notes”) at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under the ENLK Credit Facility and for general partnership purposes.

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 (the “2047 Notes”) at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year, beginning December 1, 2017. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under the ENLK Credit Facility and for general partnership purposes

Senior Unsecured Note Redemption Provisions

Each issuance of the senior unsecured notes may be fully or partially redeemed prior to an early redemption date (see "Early Redemption Date" in table below) at a redemption price equal to the greater of: (i) 100% of the principal amount of the notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the respective 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 a specified basis point premium (see "Basis Point Premium" in the table below); plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after the Early Redemption Date, the senior unsecured notes may be fully or partially redeemed at a redemption price equal to 100% of the principal amount of the applicable notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date. See applicable redemption provision terms below:

Issuance	Maturity Date of Notes	Early Redemption Date	Basis Point Premium
2019 Notes	April 1, 2019	Prior to March 1, 2019	20 Basis Points
2024 Notes	April 1, 2024	Prior to January 1, 2024	25 Basis Points
2025 Notes	June 1, 2025	Prior to March 1, 2025	30 Basis Points
2026 Notes	July 15, 2026	Prior to April 15, 2026	50 Basis Points
2044 Notes	April 1, 2044	Prior to October 1, 2043	30 Basis Points
2045 Notes	April 1, 2045	Prior to October 1, 2044	30 Basis Points
2047 Notes	June 1, 2047	Prior to June 1, 2047	40 Basis Points

Senior Unsecured Note Indentures

The indentures governing the senior unsecured notes contain covenants that, among other things, limitour 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 unsecured 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 unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies. At December 31, 2018, we were in compliance and expect to be in compliance with the covenants in the senior unsecured notes for at least the next twelve months.

(7) Income Taxes

The components of our income tax provision (benefit) are as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Current income tax provision	$ 1.8	$ 2.6	$ 1.9
Deferred tax benefit	(3.9)	(26.6)	(0.6)
Total income tax provision (benefit)	$ (2.1)	$ (24.0)	$ 1.3

Net income for financial statement purposes may differ significantly from taxable income of unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner’s tax attributes is not available to us.

The Tax Cuts and Jobs Act of 2017 resulted in a change in the federal statutory corporate tax rate from35% to 21%, effective January 1, 2018. Accordingly, we recognized a tax benefit of $24.9 million during the fourth quarter of 2017 due to the remeasurement of our deferred tax liabilities to reflect the reduction in the federal statutory corporate tax rate.

Deferred tax liabilities of $42.4 million and $46.3 million existed at December 31, 2018 and 2017, respectively. Deferred tax liabilities as of December 31, 2018 and 2017 included $38.7 million and $38.8 million, respectively, related to our wholly-owned corporate entity that was formed to acquire the common stock of Clearfield Energy, Inc. This deferred tax liability represents the future tax payable on the difference between the fair value and the carryover tax basis of the assets acquired and is expected to become payable no later than 2027.

For the year ended December 31, 2016, we recognized $1.5 million of previously recorded unrecognized income tax benefit. For the three years ended December 31, 2018, 2017, and 2016, there was no recorded unrecognized tax benefit.

Per our accounting policy election, penalties and interest related to unrecognized tax benefits are recorded to income tax expense. As of December 31, 2018, tax years 2014 through 2018 remain subject to examination by various taxing authorities.

(8) Partners' Capital

(a) Issuance of Common Units

In November 2014, we entered into an Equity Distribution Agreement (the "2014 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 to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program.

For the year ended December 31, 2016, we sold an aggregate of 10.0 million common units, generating proceeds of $167.5 million (net of $1.7 million of commissions).

In August 2017, we ceased trading under the 2014 EDA and entered into the 2017 EDA.

For the year ended December 31, 2017, we sold an aggregate of 6.2 million common units under the 2014 EDA and the 2017 EDA, generating proceeds of $106.9 million (net of $1.1 million of commissions and $0.2 million of registration fees). We used the net proceeds for general partnership purposes.

For the year ended December 31, 2018, we sold an aggregate of 2.6 million common units under the 2017 EDA, generating proceeds of $46.1 million (net of $0.5 million of commissions paid to the Sales Agents). We used the net proceeds for general partnership purposes. In connection with the announcement of the Merger, we suspended solicitation and offers under the 2017 EDA. Following the consummation of the Merger, the 2017 EDA was terminated.

(b) Class C Common Units

As of December 31, 2015, there were 7,075,433 Class C Common Units issued and outstanding. The Class C Common Units were substantially similar in all respects to our common units, except that distributions paid on the Class C Common Units could be paid in cash or in additional Class C Common Units issued in kind, as determined by our general partner in its sole discretion. Distributions on the Class C Common Units for the three months ended December 31, 2015 and March 31, 2016 were paid-in-kind through the issuance of 209,044 and 233,107 Class C Common Units on February 11, 2016 and May 12, 2016, respectively. All of the outstanding Class C Common Units were converted into common units on a one-for-one basis on May 13, 2016.

(c) Series B Preferred Units

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units representing our limited partner interests to Enfield in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the acquisition of our EOGP assets. Affiliates of Goldman Sachs and affiliates of TPG own interests in the general partner of Enfield. Prior to the close of the Merger on January 25, 2019, the Series B Preferred Units were convertible into our common units on a one-for-one basis, subject to certain adjustments, (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") was greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Series B Preferred Units would have automatically converted into a number of common units equal to the greater of (i) the number of common units into which the Series B Preferred Units would then convert and (ii) the number of Series B Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

The Series B Preferred Units will continue to be issued and outstanding following the Merger, except that certain terms of the Series B Preferred Units have been modified pursuant to an amended partnership agreement of ENLK. Subsequent to the modification, Series B Preferred Units will be exchangeable for ENLC common units in an amount equal to the number of outstanding Series B Preferred Units outstanding multiplied by the exchange ratio of 1.15, subject to certain adjustments (the "Series B Exchange Ratio"). The exchange is subject to ENLK's option to pay cash instead of issuing additional ENLC common units, and can occur in whole or in part at Enfield's option at any time, or in whole at our option, provided the daily volume-weighted average closing price of the ENLC common units (the "ENLC VWAP") exchange for the 30 trading days ending two trading days prior to the exchange is greater than 150% of the Issue Price divided by the conversion ratio of 1.15.

For each of the calendar quarters between March 31, 2016 through June 30, 2017, Enfield received a quarterly distribution equal to an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Series B Preferred Units. Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions are payable quarterly in cash at an amount equal to $0.28125 per Series B Preferred Unit (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Series B Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the issue price of $15.00.

Beginning with the quarter ending March 31, 2019, the holder of the Series B Preferred Units will be entitled to quarterly cash distributions and distributions in-kind of additional Series B Preferred Units as described below. The quarterly in-kind distribution (the "Series B PIK Distribution") will equal the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) the number of Series B Preferred Units equal to the quotient of (x) the excess (if any) of (1) the distribution that would have been payable by ENLC had the Series B Preferred Units been exchanged for ENLC common units but applying a one-to-one exchange ratio (subject to certain adjustments) instead of the Series B Exchange Ratio, over (2) the Cash Distribution Component, divided by (y) the Issue Price. The quarterly cash distribution will consist of the Cash Distribution Component plus an amount in cash that will be determined based on a comparison of the value (applying the Issue Price) of (i) the Series B PIK Distribution and (ii) the Series B Preferred Units that would have been distributed in the Series B PIK Distribution if such calculation applied the Series B Exchange Ratio instead of the one-to-one ratio (subject to certain adjustments).

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. For the years ended December 31, 2018, 2017, and 2016, $90.2 million, $86.0 million, and $69.9 million of income was allocated to the Series B Preferred Units, respectively. A summary of the distribution activity relating to the Series B Preferred Units for the years ended December 31, 2018, 2017, and 2016 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash distribution (in millions)		Date paid/payable
2018				
First Quarter of 2018	416,657	$	16.2	May 14, 2018
Second Quarter of 2018	419,678	$	16.3	August 13, 2018
Third Quarter of 2018	422,720	$	16.4	November 13, 2018
Fourth Quarter of 2018	425,785	$	16.5	February 13, 2019
2017				
First Quarter of 2017	1,154,147	$	—	May 12, 2017
Second Quarter of 2017	1,178,672	$	—	August 11, 2017
Third Quarter of 2017	410,681	$	15.9	November 13, 2017
Fourth Quarter of 2017	413,658	$	16.1	February 13, 2018
2016				
First Quarter of 2016	992,445	$	—	May 12, 2016
Second Quarter of 2016	1,083,589	$	—	August 11, 2016
Third Quarter of 2016	1,106,616	$	—	November 10, 2016
Fourth Quarter of 2016	1,130,131	$	—	February 13, 2017

(d) Series C Preferred Units

In September 2017, we issued 400,000 Series C Preferred Units representing our limited partner interests at a price to the public of $1,000 per unit. We used the net proceeds of $394.0 million for capital expenditures, general partnership purposes, and to repay borrowings under the ENLK Credit Facility. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event. Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period. For the years ended December 31, 2018 and 2017, $24.0 million and $6.7 million of income, respectively, was allocated to the Series C Preferred Units.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September, and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%. For the years ended December 31, 2018 and 2017, we made distributions of $24.0 million and $5.6 million to holders of Series C Preferred Units, respectively.

Following the Merger, the Series C Preferred Units remained issued and outstanding with the terms set forth above.

(e) Common Unit Distributions

Prior to the Merger, unless restricted by the terms of the ENLK Credit Facility and/or the indentures governing our senior unsecured notes, we were required to make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions were made to the general partner in accordance with its then 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 were achieved. The general partner was not entitled to its incentive distributions with respect to the Class C Common Units issued in kind. In addition, the general partner was not entitled to its incentive distributions with respect to (i) distributions on the Series B Preferred Units until such units convert into common units or (ii) the Series C Preferred Units.

As of December 31, 2018, our general partner owned the general partner interest in us and all of our incentive distribution rights. Our general partner was entitled to receive incentive distributions if the amount we distributed with respect to any quarter exceeded levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner was entitled to 13.0% of amounts we distributed in excess of $0.25 per unit, 23.0% of the amounts we distributed in excess of $0.3125 per unit, and 48.0% of amounts we distributed in excess of $0.375 per unit. At the close of the Merger, our general partner's incentive distribution rights in ENLK were eliminated. See "Note 18—Subsequent Events" for more information regarding the Merger and related transactions.

A summary of the distribution activity relating to the common units for the years ended December 31, 2018, 2017, and 2016 is provided below:

Declaration period	Distribution/unit	Date paid/payable
2018		
First Quarter of 2018	$ 0.390	May 14, 2018
Second Quarter of 2018	$ 0.390	August 13, 2018
Third Quarter of 2018	$ 0.390	November 13, 2018
Fourth Quarter of 2018	$ 0.390	February 13, 2019
2017		
First Quarter of 2017	$ 0.390	May 12, 2017
Second Quarter of 2017	$ 0.390	August 11, 2017
Third Quarter of 2017	$ 0.390	November 13, 2017
Fourth Quarter of 2017	$ 0.390	February 13, 2018
2016		
First Quarter of 2016	$ 0.390	May 12, 2016
Second Quarter of 2016	$ 0.390	August 11, 2016
Third Quarter of 2016	$ 0.390	November 11, 2016
Fourth Quarter of 2016	$ 0.390	February 13, 2017

(f) Earnings Per Unit and Dilution Computations

As required under ASC 260, *Earnings Per Share*, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities for earnings per unit calculations. The following table reflects the computation of basic and diluted earnings per limited partner unit for the periods presented (in millions, except per unit amounts):

	Year Ended December 31,		
	2018	2017	2016
Distributed earnings allocated to:			
Common units (1)	$ 548.1	$ 541.2	$ 520.0
Unvested restricted units (1)	4.4	4.0	3.5
Total distributed earnings	$ 552.5	$ 545.2	$ 523.5
Undistributed loss allocated to:			
Common units	$ (727.5)	$ (523.5)	$ (1,177.6)
Unvested restricted units	(5.8)	(3.8)	(8.0)
Total undistributed loss	$ (733.3)	$ (527.3)	$ (1,185.6)
Net income (loss) allocated to:			
Common units	$ (179.4)	$ 17.7	$ (657.6)
Unvested restricted units	(1.4)	0.2	(4.5)
Total limited partners' interest in net income (loss)	$ (180.8)	$ 17.9	$ (662.1)
Basic and diluted net income (loss) per unit:			
Basic	$ (0.51)	$ 0.05	$ (1.99)
Diluted	$ (0.51)	$ 0.05	$ (1.99)

(1) Represents distribution activity consistent with the distribution activity table in section "(e) Common Unit Distributions" above.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2018, 2017, and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
Basic weighted average units outstanding:			
Weighted average limited partner basic common units outstanding (1)	351.3	346.9	333.3
Diluted weighted average units outstanding:			
Weighted average limited partner basic common units outstanding (1)	351.3	346.9	333.3
Dilutive effect of non-vested restricted units (2)	—	1.4	—
Total weighted average limited partner diluted common units outstanding	351.3	348.3	333.3

(1) Weighted average limited partner basic common units outstanding for the years ended December 31, 2016 included the weighted average impact of 2,740,273 Class C Units, which converted into common units on May 13, 2016.
(2) All common unit equivalents were antidilutive for the years ended December 31, 2018 and 2016 because the limited partners were allocated a net loss.

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.

Prior to the closing of the Merger and for the years ended December 31, 2018, 2017, and 2016, net income was allocated to our general partner in an amount equal to its incentive distribution rights as described in section "(e) Common Unit Distributions" above. Our general partner's share of net income consisted of incentive distribution rights to the extent earned, a deduction for unit-based compensation attributable to ENLC's restricted units, and the percentage interest ofour net income (loss) adjusted for ENLC's unit-based compensation specifically allocated to our general partner. The net income (loss) allocated to the general partner is as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Income allocation for incentive distributions	$ 59.5	$ 58.9	$ 56.8
Unit-based compensation attributable to ENLC's restricted units	(20.3)	(21.0)	(14.7)
General partner share of net income (loss)	(0.6)	0.4	(2.6)
General partner interest in net income	$ 38.6	$ 38.3	$ 39.5

(9) Investment in Unconsolidated Affiliates

Our unconsolidated investments consisted of:

- a 38.75% ownership interest in GCF atDecember 31, 2018, 2017, and 2016;
- an approximate 30.0% ownership in the Cedar Cove JV atDecember 31, 2018, 2017, and 2016. On November 9, 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc.; and
- an approximate 31% ownership interest in HEP at December 31, 2016, which was sold in March 2017 for aggregate net proceeds of$189.7 million.

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

	Year Ended December 31,		
	2018	2017	2016
GCF			
Distributions	$ 22.3	$ 12.7	$ 7.5
Equity in income	$ 15.8	$ 12.6	$ 3.4
HEP			
Contributions (1)	$ —	$ —	$ 45.0
Distributions (2)	$ —	$ —	$ 50.2
Equity in income (loss) (3)	$ —	$ (3.4)	$ (23.3)
Cedar Cove JV			
Contributions	$ 0.1	$ 12.6	$ 28.8
Distributions	$ 0.4	$ 0.8	$ —
Equity in income	$ (2.5)	$ 0.4	$ —
Total			
Contributions (1)	$ 0.1	$ 12.6	$ 73.8
Distributions (2)	$ 22.7	$ 13.5	$ 57.7
Equity in income (loss) (3)	$ 13.3	$ 9.6	$ (19.9)

(1) Contributions for the year ended December 31, 2016 included $32.7 million of contributions to HEP for preferred units issued by HEP. These preferred units were redeemed during the third quarter 2016.
(2) Distributions for the year ended December 31, 2016 included a redemption of $32.7 million of preferred units issued by HEP.
(3) Included losses of $3.4 million and $20.1 million for the years ended December 31, 2017 and 2016, respectively, related to the sale of our HEP interests.

The following table shows the balances related to our investment in unconsolidated affiliates as of December 31, 2018 and 2017 (in millions):

	December 31, 2018	December 31, 2017
GCF	$ 41.9	$ 48.4
Cedar Cove JV	38.2	41.0
Total investments in unconsolidated affiliates	$ 80.1	$ 89.4

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

We and ENLC each have similar unit-based compensation payment plans for officers and employees. We have historically granted unit-based awards under the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan"), and ENLC grants unit-based awards under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 Plan"). As of the effective time of the Merger, (i) ENLC assumed all obligations in respect of the GP Plan and the outstanding awards granted thereunder (the "Legacy ENLK Awards") and (ii) the common units representing limited partner interests in ENLK subject to such Legacy ENLK Awards will convert into common units representing limited liability company interests in ENLC using the exchange ratio (as defined in the Merger Agreement) as the conversion rate. In connection with the consummation of the Merger, no additional awards will be granted under the GP Plan.

We account for unit-based compensation in accordance with ASC 718, *Stock Compensation* ("ASC 718"), which requires that compensation related to all unit-based awards be recognized in the consolidated financial statements. Unit-based compensation cost is valued at fair value at the date of grant, and that grant date fair value is recognized as expense over each award's requisite service period with a corresponding increase to equity or liability based on the terms of each award and the appropriate accounting treatment under ASC 718. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to ENLC's officers and employees is recorded by us since ENLC has no substantial or managed operating activities other than its interests in us. Amounts recognized on the consolidated financial statements with respect to these plans are as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Cost of unit-based compensation charged to general and administrative expense	$ 30.0	$ 37.1	$ 23.4
Cost of unit-based compensation charged to operating expense	10.8	10.7	6.6
Total unit-based compensation expense	$ 40.8	$ 47.8	$ 30.0

All unit-based awards issued and outstanding immediately prior to the effective time of the Merger under the GP Plan have been converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting of terms of applicable awards related to the performance of ENLC.

(b) EnLink Midstream Partners, LP's Restricted Incentive Units

ENLK restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of ENLK common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2018 is provided below:

	Year Ended December 31, 2018	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,980,224	$ 15.81
Granted (1)	1,590,100	15.27
Vested (1)(2)	(835,115)	19.68
Forfeited	(178,939)	12.75
Non-vested, end of period	2,556,270	$ 14.43
Aggregate intrinsic value, end of period (in millions)	$ 28.1	

(1) Restricted incentive units typically vest at the end of three years. In March 2018, our general partner granted 200,753 restricted incentive units with a fair value of $3.0 million to officers and certain employees as bonus payments for 2017, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units include 261,063 units withheld for payroll taxes paid on behalf of employees.

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) for the years ended December 31, 2018, 2017, and 2016 is provided below (in millions):

	Year Ended December 31,		
EnLink Midstream Partners, LP Restricted Incentive Units:	**2018**	**2017**	**2016**
Aggregate intrinsic value of units vested	$ 13.1	$ 16.6	$ 4.1
Fair value of units vested	$ 16.4	$ 22.6	$ 9.5

As of December 31, 2018, there was $18.4 million of unrecognized compensation cost related to non-vested ENLK restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(c) EnLink Midstream Partners, LP's Performance Units

Our general partner has granted performance awards under the GP Plan. The performance award agreements provided that the vesting of restricted incentive units granted thereunder was dependent on the achievement of certain total shareholder return ("TSR") performance goals relative to the TSR achievement of a peer group of companies (the "Peer Companies") over the applicable performance period. The performance award agreements contemplated that the Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units vested based on the percentile ranking of the average of ENLK's and ENLC's TSR achievement ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Peer Companies.

At the end of the vesting period, recipients received distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units ranged from zero to 200% of the units granted depending on the EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. As of the effective time of the Merger, the performance metric for such performance awards was modified such that the performance metric will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods after the effective time of the Merger. The fair value of each performance unit was estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated Peer Companies' securities; (iii) an estimated ranking of us among the designated Peer Companies; and (iv) the distribution yield. The fair value of the performance unit on the date of grant was expensed over a vesting period of approximately three years.

The following table presents a summary of the grant-date fair value of performance units granted and the related assumptions by performance unit grant date:

EnLink Midstream Partners, LP Performance Units:	March 2018	March 2017	October 2016	February 2016	January 2016
TSR price	$15.44	$17.55	$17.71	$14.82	$14.82
Risk-free interest rate	2.38%	1.62%	0.91%	0.89%	1.10%
Volatility factor	43.85%	43.94%	44.62%	42.33%	39.71%
Distribution yield	10.50%	8.70%	8.80%	19.20%	12.10%

The following table presents a summary of the performance units:

	Year Ended December 31, 2018	
EnLink Midstream Partners, LP Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	585,285	$ 20.52
Granted	256,345	19.24
Vested (1)	(313,610)	24.43
Forfeited	(76,351)	16.62
Non-vested, end of period	451,669	$ 17.74
Aggregate intrinsic value, end of period (in millions)	$ 5.0	

(1) Vested units included 112,101 units withheld for payroll taxes paid on behalf of employees and 120,250 units that vested as a result of the GIP Transaction, net of units withheld for payroll taxes.

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the year ended December 31, 2018 is provided below (in millions). No performance units vested for the years ended2017 and 2016.

EnLink Midstream Partners, LP Performance Units:	Year Ended December 31, 2018
Aggregate intrinsic value of units vested	$ 5.0
Fair value of units vested	$ 7.7

As of December 31, 2018, there was $6.1 million of unrecognized compensation expense that related to non-vested performance units. That cost is expected to be recognized over a weighted-average period of 1.7 years.

In connection with the GIP Transaction, certain outstanding performance unit agreements were modified to, among other things: (i) provide that the awards granted thereunder did not vest due to the closing of the GIP Transaction and (ii) increase the minimum vesting of units from zero to 100% as described in our Current Report on Form 8-K filed with the Securities and Exchange Commission (the "Commission") on July 23, 2018. The modified performance units retained the original vesting schedules. As a result of the modifications, we will recognize an additional $2.3 million compensation cost over the life of these ENLK performance units.

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

ENLC restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of ENLC common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2018 is provided below:

	Year Ended December 31, 2018	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,889,310	$ 16.33
Granted (1)	1,473,195	15.76
Vested (1)(2)	(769,848)	21.40
Forfeited	(166,790)	12.74
Non-vested, end of period	2,425,867	$ 14.62
Aggregate intrinsic value, end of period (in millions)	$ 23.0	

(1) Restricted incentive units typically vest at the end of three years. In March 2018, ENLC granted 194,185 restricted incentive units with a fair value of $3.0 million to officers and certain employees as bonus payments for 2017, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units include 244,123 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2018, 2017, and 2016 is provided below (in millions):

	Year Ended December 31,		
EnLink Midstream, LLC Restricted Incentive Units:	**2018**	**2017**	**2016**
Aggregate intrinsic value of units vested	$ 12.8	$ 15.3	$ 4.1
Fair value of units vested	$ 16.5	$ 22.2	$ 12.4

As of December 31, 2018, there was $17.9 million of unrecognized compensation costs related to non-vested ENLC restricted incentive units. That cost is expected to be recognized over a weighted average period of 1.8 years.

(e) EnLink Midstream, LLC's Performance Units

ENLC grants performance awards under the 2014 Plan. The performance award agreements provide that the vesting of performance units (i.e., performance-based restricted incentive units) granted thereunder is dependent on the achievement of certain TSR performance goals relative to the TSR achievement of the Peer Companies over the applicable performance period. At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units ranges from zero to 200% of the units granted depending on the EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. As of the effective time of the Merger, the performance metric for such performance awards was modified such that the performance metric will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods after the effective time of the Merger. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLC's common units and the designated Peer Companies' securities; (iii) an estimated ranking of ENLC among the designated Peer Companies, and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years. The following table presents a summary of the grant-date fair value assumptions by performance unit grant date:

EnLink Midstream, LLC Performance Units:	March 2018	March 2017	October 2016	February 2016	January 2016
TSR price	$ 16.55	$ 18.29	$ 16.75	$ 15.38	$ 15.38
Risk-free interest rate	2.38%	1.62%	0.91%	0.89%	1.10%
Volatility factor	51.36%	52.07%	52.89%	52.05%	46.02%
Distribution yield	6.70%	5.40%	6.10%	14.00%	8.60%

The following table presents a summary of the performance units:

	Year Ended December 31, 2018	
EnLink Midstream, LLC Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	548,839	$ 22.14
Granted	223,865	21.63
Vested (1)	(283,637)	27.25
Forfeited	(70,918)	17.75
Non-vested, end of period	418,149	$ 19.15
Aggregate intrinsic value, end of period (in millions)	$ 4.0	

(1) Vested units included 100,109 units withheld for payroll taxes paid on behalf of employees and 109,819 units that vested as a result of the GIP Transaction, net of units withheld for payroll taxes.

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the year ended December 31, 2018 is provided below (in millions). No performance units vested for the years ended2017 and 2016.

EnLink Midstream, LLC Performance Units:	Year Ended December 31, 2018
Aggregate intrinsic value of units vested	$ 4.7
Fair value of units vested	$ 7.7

As of December 31, 2018, there was $5.9 million of unrecognized compensation expense that related to non-vestedperformance units. That cost is expected to be recognized over a weighted-average period of 1.6 years.

In connection with the GIP Transaction, certain outstanding performance unit agreements were modified to among other things, (i) provide that the awards granted thereunder did not vest due to the closing of the GIP Transaction and (ii) increase the minimum vesting of units from zero to 100% as described in our Current Report on Form 8-K filed with the Commission on July 23, 2018. The modified performance units retained the original vesting schedules. As a result of the modifications, we will recognize an additional $2.1 million compensation cost over the life of these ENLC performance units.

(f) Benefit Plan

ENLK maintains a tax-qualified 401(k) plan whereby it matches 100% of every dollar contributed up to 6% of an employee's eligible compensation plus a 2% non-discretionary contribution (not to exceed the maximum amount permitted by law). Contributions of $8.3 million, $7.6 million, and $7.4 million were made to the plan for the years ended December 31, 2018, 2017, and 2016, respectively.

(11) Derivatives

Interest Rate Swaps

We periodically enter into interest rate swaps in connection with new debt issuances. During the debt issuance process, we are exposed to variability in future long-term debt interest payments that may result from changes in the benchmark interest rate (commonly the U.S. Treasury yield) prior to the debt being issued. In order to hedge this variability, we enter into interest rate swaps to effectively lock in the benchmark interest rate at the inception of the swap. Prior to 2017, we did not designate interest rate swaps as hedges and, therefore, included the associated settlement gains and losses as interest expense, net of interest income on the consolidated statements of operations.

In May 2017, we entered into an interest rate swap in connection with the issuance of our 2047 Notes. In accordance with ASC 815, we designated this swap as a cash flow hedge. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated comprehensive loss on the consolidated balance sheets. We will amortize the settlement loss into interest expense on the consolidated statements of operations over the term of the 2047 Notes. There was no ineffectiveness related to the hedge. We have no open interest rate swap positions as of December 31, 2018. In addition, the settlement loss is included as an operating cash outflow on the consolidated statement of cash flows for the year ended December 31, 2017.

For the years ended December 31, 2018 and 2017, we amortized an immaterial amount of the settlement loss into interest expense from accumulated other comprehensive income (loss). We expect to recognize and additional $0.1 million of interest expense out of accumulated other comprehensive income (loss) over the next twelve months.

In July 2016, we entered into an interest rate swap in connection with the issuance of the 2026 Notes. We did not designate this swap as a cash flow hedge. Upon settlement of the interest rate swap in July 2016, we recorded the associated $0.4 million gain on settlement as interest expense, net of interest income in the consolidated statement of operations for the year ended December 31, 2016.

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Commodity swaps are used both to manage and hedge price and location risk related to these market exposures and to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of crude, condensate, natural gas, and NGLs. We do not designate commodity swaps as cash flow or fair value hedges for hedge accounting treatment under ASC 815. Therefore, changes in the fair value of our derivatives are recorded in revenue in the period incurred. In addition, our commodity risk management policy does not allow us to take speculative positions with our derivative contracts.

We commonly enter into index (float-for-float) or fixed-for-float swaps in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, NGLs, and crude oil. For natural gas, index swaps are used to protect against the price exposure of daily priced gas versus first-of-month priced gas. For condensate, crude oil, and natural gas, index swaps 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) where we receive a percentage of liquids as a fee for processing third-party gas or where we receive a portion of the proceeds of the sales of natural gas and liquids as a fee, (2) in the natural gas processing and fractionation components of our business and (3) where we are mitigating the price risk for product held in inventory or storage.

Assets and liabilities related to our derivative contracts are included in the fair value of derivative assets and liabilities, and the change in fair value of these contracts is recorded net as a gain (loss) on derivative activity on the consolidated statements of operations. We estimate the fair value of all of our derivative contracts based upon actively-quoted prices of the underlying commodities.

The components of gain (loss) on derivative activity in the consolidated statements of operations related to commodity swaps are (in millions):

	Year Ended December 31,		
	2018	2017	2016
Change in fair value of derivatives	$ 10.1	$ 4.7	$ (20.1)
Realized gain (loss) on derivatives	(4.9)	(8.9)	9.0
Gain (loss) on derivative activity	$ 5.2	$ (4.2)	$ (11.1)

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

	December 31, 2018	December 31, 2017
Fair value of derivative assets — current	$ 28.6	$ 6.8
Fair value of derivative assets — long-term	4.1	—
Fair value of derivative liabilities — current	(21.8)	(8.4)
Fair value of derivative liabilities — long-term	(2.4)	—
Net fair value of derivatives	$ 8.5	$ (1.6)

Set forth below are the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2018 (in millions). The remaining term of the contracts extend no later than December 2022.

		December 31, 2018		
Commodity	**Instruments**	**Unit**	**Volume**	**Fair Value**
NGL (short contracts)	Swaps	Gallons	(29.0)	$ 4.5
NGL (long contracts)	Swaps	Gallons	7.7	0.1
Natural Gas (short contracts)	Swaps	MMBtu	(9.0)	(1.6)
Natural Gas (long contracts)	Swaps	MMBtu	14.9	(1.5)
Crude and Condensate (short contracts)	Swaps	MMbbls	(12.9)	23.6
Crude and Condensate (long contracts)	Swaps	MMbbls	1.0	(16.6)
Total fair value of derivatives				$ 8.5

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with financial institutions when entering into financial derivatives on commodities. We have entered into Master ISDAs that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing swap contracts, the maximum loss on our gross receivable position of $32.7 million as of December 31, 2018 would be reduced to $9.4 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(12) Fair Value Measurements

ASC 820, *Fair Value Measurements and Disclosures* ("ASC 820"), sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under 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.

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

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

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

	Level 2	
	December 31, 2018	December 31, 2017
Commodity Swaps (1)	$ 8.5	$ (1.6)

(1) The fair values of derivative contracts included in assets or liabilities for risk management activities represent the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for our credit risk and/or the counterparty credit risk as required under ASC 820.

Fair Value of Financial Instruments

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

	December 31, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,319.6	$ 3,953.6	$ 3,467.8	$ 3,575.6
Installment Payables	$ —	$ —	$ 249.5	$ 249.6
Obligations under capital lease	$ 2.5	$ 2.2	$ 4.1	$ 3.4
Secured term loan receivable	$ 51.1	$ 51.1	$ —	$ —

(1) The carrying value of long-term debt, including current maturities of long-term debt, is reduced by debt issuance costs of $24.3 million and $25.9 million at December 31, 2018 and 2017, respectively. The respective fair values do not factor in debt issuance costs.

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

As of December 31, 2018 and 2017, we had total borrowings under senior unsecured notes of$3.5 billion for each period, respectively, maturing between 2019 and 2047 with fixed interest rates ranging from 2.7% to 5.6%. The fair values of all senior unsecured notes and installment payables as ofDecember 31, 2018 and 2017 were based on Level 2 inputs from third-party market quotations. The fair values of obligations under capital leases and the secured term loan receivable were calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) Leases—Lessee

We have operating leases for office space, office, and field equipment.

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

2019	$	14.1
2020		10.3
2021		8.7
2022		8.6
2023		8.8
Thereafter		49.8
Total	$	100.3

Operating lease rental expense was approximately $52.5 million, $54.5 million, and $59.6 million for the years ended December 31, 2018, 2017, and 2016, respectively.

(b) Change of Control and Severance Agreements

Certain members of our management are parties to severance and change of control agreements with the Operating Partnership.The severance and change in control agreements provide those individuals with severance payments in certain circumstances and prohibit such individuals from, among other things, competing with our general partner or its affiliates during his or her employment. In addition, the severance and change of control agreements prohibit subject individuals from, among other things, disclosing confidential information about our general partner or interfering with a client or customer of our general partner or its affiliates, in each case during his or her employment and for certain periods (including indefinite periods) following the termination of such person's employment.

(c) Environmental Issues

The operation of pipelines, plants, and other facilities for the gathering, processing, transmitting, stabilizing, fractionating, storing, 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, partner, or operator of these facilities, we must comply with United States laws and regulations at the federal, state, and local levels that relate to air and water quality, hazardous and solid waste management and disposal, oil spill prevention, climate change, endangered species, and other environmental matters. The cost of planning, designing, constructing, and operating pipelines, plants, and other facilities must account for compliance with environmental laws and regulations and safety standards. Federal, state, or local administrative decisions, developments in the federal or state court systems, or other governmental or judicial actions may influence the interpretation and enforcement of environmental laws and regulations and may thereby increase compliance costs. Failure to comply with these laws and regulations may trigger a variety of administrative, civil, and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition, or cash flows. However, we cannot provide assurance that future events, such as changes in existing laws, regulations, or enforcement policies, the promulgation of new laws or regulations, or the discovery or development of new factual circumstances will not cause us to incur material costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

(d) Litigation Contingencies

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

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time, we (or our subsidiaries) are a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation.

Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations, financial condition, or cash flows.

We 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, resulting in damage to certain of our facilities. In order to recover our losses from responsible parties, we sued the operator of a failed cavern in the area, and its insurers, as well as other parties we alleged to have contributed to the formation of the sinkhole seeking recovery for these losses. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, and we subsequently reached settlements regarding the entirety of our claims in both lawsuits. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. We secured additional settlement payments during 2017, which resulted in the recognition of “Gain on litigation settlement” of $26.0 million on the consolidated statement of operations for the year ended December 31, 2017.

(14) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served and the nature of operating activity. As of December 31, 2018, our reportable segments consisted of the following: natural gas gathering, processing, transmission, and fractionation operations located in North Texas and the Permian Basin primarily in West Texas (“Texas”), natural gas pipelines, processing plants, storage facilities, NGL pipelines, and fractionation assets in Louisiana (“Louisiana”), natural gas gathering and processing operations located throughout Oklahoma (“Oklahoma”), and crude rail, truck, pipeline, and barge facilities in West Texas, South Texas, Louisiana, Oklahoma, and the Ohio River Valley (“Crude and Condensate”). Operating activity for intersegment eliminations is shown in the Corporate segment. Our sales are derived from external domestic customers. We evaluate the performance of our operating segments based on segment profits.

Corporate assets consist primarily of cash, property, and equipment, including software, for general corporate support, debt financing costs, and unconsolidated affiliate investments in GCF and the Cedar Cove JV as of December 31, 2018, 2017, and 2016. As of December 31, 2016, our Corporate assets also included our unconsolidated affiliate investment in HEP. In December 31, 2016, we entered into an agreement to sell our ownership interest in HEP, and we finalized the sale in March 2017.

Based on the disclosure requirements of ASC 606, we are presenting revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues. As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the year ended December 31, 2018 are presented to conform to ASC 606 accounting and disclosure requirements. Prior periods presented in the consolidated financial statements and accompanying notes were not restated in accordance with ASC 606.

Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2018						
Natural gas sales	$ 292.9	$ 531.1	$ 189.7	$ —	$ —	$ 1,013.7
NGL sales	28.6	2,786.3	25.2	0.9	—	2,841.0
Crude oil and condensate sales	—	0.5	0.7	2,656.4	—	2,657.6
Product sales	321.5	3,317.9	215.6	2,657.3	—	6,512.3
Natural gas sales—related parties	—	—	2.5	—	—	2.5
NGL sales—related parties	503.5	47.4	590.8	—	(1,104.3)	37.4
Crude oil and condensate sales—related parties	49.3	0.3	85.6	3.3	(137.4)	1.1
Product sales—related parties	552.8	47.7	678.9	3.3	(1,241.7)	41.0
Gathering and transportation	177.9	68.8	149.1	3.1	—	398.9
Processing	101.0	3.3	122.8	—	—	227.1
NGL services	—	59.6	—	—	—	59.6
Crude services	—	—	0.6	66.5	—	67.1
Other services	9.6	0.6	0.2	0.2	—	10.6
Midstream services	288.5	132.3	272.7	69.8	—	763.3
Gathering and transportation—related parties	122.7	—	80.6	—	—	203.3
Processing—related parties	108.6	—	48.4	—	—	157.0
NGL services—related parties	—	3.3	—	—	(3.3)	—
Crude services—related parties	—	—	1.5	14.9	—	16.4
Other services—related parties	0.5	—	—	—	—	0.5
Midstream services—related parties	231.8	3.3	130.5	14.9	(3.3)	377.2
Revenue from contracts with customers	1,394.6	3,501.2	1,297.7	2,745.3	(1,245.0)	7,693.8
Cost of sales	(753.9)	(3,158.7)	(744.0)	(2,596.4)	1,245.0	(6,008.0)
Operating expenses	(180.6)	(108.3)	(89.2)	(75.3)	—	(453.4)
Gain on derivative activity	—	—	—	—	5.2	5.2
Segment profit	$ 460.1	$ 234.2	$ 464.5	$ 73.6	$ 5.2	$ 1,237.6
Depreciation and amortization	$ (216.2)	$ (122.7)	$ (178.1)	$ (51.6)	$ (8.7)	$ (577.3)
Impairments	$ (232.0)	$ (24.6)	$ —	$ (109.2)	$ —	$ (365.8)
Goodwill	$ —	$ —	$ 190.3	$ —	$ —	$ 190.3
Capital expenditures	$ 249.4	$ 47.0	$ 412.5	$ 135.7	$ 5.3	$ 849.9
Total assets	$ 2,925.3	$ 2,347.9	$ 3,116.5	$ 959.3	$ 222.3	$ 9,571.3

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2017						
Product sales	$ 325.0	$ 2,529.6	$ 128.8	$ 1,375.0	$ —	$ 4,358.4
Product sales—related parties	500.3	45.0	349.4	0.8	(750.6)	144.9
Midstream services	116.3	220.6	155.0	60.4	—	552.3
Midstream services—related parties	424.3	136.4	241.6	17.4	(131.5)	688.2
Cost of sales	(772.3)	(2,618.1)	(522.9)	(1,330.3)	882.1	(4,361.5)
Operating expenses	(172.7)	(101.3)	(64.6)	(80.1)	—	(418.7)
Loss on derivative activity	—	—	—	—	(4.2)	(4.2)
Segment profit (loss)	$ 420.9	$ 212.2	$ 287.3	$ 43.2	$ (4.2)	$ 959.4
Depreciation and amortization	$ (215.2)	$ (116.1)	$ (156.6)	$ (47.5)	$ (9.9)	$ (545.3)
Impairments	$ —	$ (0.8)	$ —	$ (16.3)	$ —	$ (17.1)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 145.4	$ 75.1	$ 442.1	$ 79.1	$ 26.4	$ 768.1
Total assets	$ 3,094.8	$ 2,408.5	$ 2,836.7	$ 929.5	$ 144.5	$ 9,414.0

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2016						
Product sales	$ 237.2	$ 1,632.5	$ 48.5	$ 1,090.7	$ —	$ 3,008.9
Product sales—related parties	287.6	57.8	120.4	1.5	(333.0)	134.3
Midstream services	104.2	215.4	82.2	65.4	—	467.2
Midstream services—related parties	439.3	95.8	185.9	18.9	(86.8)	653.1
Cost of sales	(483.4)	(1,729.0)	(184.9)	(1,038.0)	419.8	(3,015.5)
Operating expenses	(168.5)	(96.6)	(52.1)	(81.3)	—	(398.5)
Loss on derivative activity	—	—	—	—	(11.1)	(11.1)
Segment profit (loss)	$ 416.4	$ 175.9	$ 200.0	$ 57.2	$ (11.1)	$ 838.4
Depreciation and amortization	$ (196.9)	$ (114.8)	$ (140.6)	$ (42.4)	$ (9.2)	$ (503.9)
Impairments	$ (473.1)	$ —	$ —	$ (93.2)	$ —	$ (566.3)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 217.9	$ 79.1	$ 295.7	$ 74.3	$ 9.1	$ 676.1
Total assets	$ 3,142.6	$ 2,349.3	$ 2,524.5	$ 836.8	$ 300.2	$ 9,153.4

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

	Year Ended December 31,		
	2018	2017	2016
Segment profit	$ 1,237.6	$ 959.4	$ 838.4
General and administrative expenses	(130.2)	(123.5)	(119.3)
Depreciation and amortization	(577.3)	(545.3)	(503.9)
Loss on disposition of assets	(0.4)	—	(13.2)
Impairments	(365.8)	(17.1)	(566.3)
Gain on litigation settlement	—	26.0	—
Operating income (loss)	$ 163.9	$ 299.5	$ (364.3)

(15) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below (in millions, except per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018					
Revenues	$ 1,761.7	$ 1,764.7	$ 2,114.3	$ 2,058.3	$ 7,699.0
Impairments	$ —	$ —	$ 24.6	$ 341.2	$ 365.8
Operating income (loss)	$ 106.6	$ 150.1	$ 92.5	$ (185.3)	$ 163.9
Net income (loss) attributable to ENLK	$ 60.1	$ 98.9	$ 43.2	$ (230.2)	$ (28.0)
General partner interest in net income	$ 10.6	$ 11.2	$ 7.7	$ 9.1	$ 38.6
Limited partners' interest in net income (loss) attributable to ENLK	$ 21.6	$ 58.9	$ 5.2	$ (266.5)	$ (180.8)
Net income (loss) attributable to ENLK per limited partners' unit:					
Basic common unit	$ 0.06	$ 0.17	$ 0.01	$ (0.75)	$ (0.51)
Diluted common unit	$ 0.06	$ 0.17	$ 0.01	$ (0.75)	$ (0.51)
2017					
Revenues	$ 1,321.9	$ 1,263.6	$ 1,397.9	$ 1,756.2	$ 5,739.6
Impairments	$ 7.0	$ —	$ 1.8	$ 8.3	$ 17.1
Operating income	$ 57.6	$ 70.4	$ 73.4	$ 98.1	$ 299.5
Net income attributable to ENLK	$ 18.1	$ 29.6	$ 25.5	$ 75.7	$ 148.9
General partner interest in net income	$ 5.9	$ 10.8	$ 10.6	$ 11.0	$ 38.3
Limited partners' interest in net income (loss) attributable to ENLK	$ (9.3)	$ (0.5)	$ (8.6)	$ 36.3	$ 17.9
Net income (loss) attributable to ENLK per limited partners' unit:					
Basic common unit	$ (0.03)	$ —	$ (0.02)	$ 0.10	$ 0.05
Diluted common unit	$ (0.03)	$ —	$ (0.02)	$ 0.10	$ 0.05
2016					
Revenues	$ 889.7	$ 1,033.2	$ 1,104.6	$ 1,224.9	$ 4,252.4
Impairments	$ 566.3	$ —	$ —	$ —	$ 566.3
Operating income (loss)	$ (515.9)	$ 46.4	$ 66.9	$ 38.3	$ (364.3)
Net income (loss) attributable to ENLK	$ (560.4)	$ 5.0	$ 18.8	$ (28.6)	$ (565.2)
General partner interest in net income	$ 7.4	$ 10.6	$ 10.8	$ 10.7	$ 39.5
Limited partners' interest in net loss attributable to ENLK	$ (567.2)	$ (23.5)	$ (11.4)	$ (60.0)	$ (662.1)
Net loss attributable to ENLK per limited partners' unit:					
Basic common unit	$ (1.74)	$ (0.07)	$ (0.03)	$ (0.18)	$ (1.99)
Diluted common unit	$ (1.74)	$ (0.07)	$ (0.03)	$ (0.18)	$ (1.99)

(16) Supplemental Cash Flow Information

The following schedule summarizes cash paid for interest and income taxes, non-cash investing activities, and non-cash financing activities for the periods presented (in millions):

	Year Ended December 31,		
Supplemental disclosures of cash flow information:	**2018**	**2017**	**2016**
Cash paid for interest	$ 182.6	$ 163.8	$ 132.5
Cash paid for income taxes	$ 1.5	$ 4.8	$ 2.8
Non-cash investing activities:			
Non-cash accrual of property and equipment	$ 6.8	$ (22.7)	$ 13.1
Discounted secured term loan receivable from contract restructuring	$ 47.7	$ —	$ —
Non-cash financing activities:			
Installment payable, net of discount of $79.1 million (1)	$ —	$ —	$ 420.9
Contribution from ENLC (2)	$ —	$ —	$ 237.1

(1) We incurred installment purchase obligations, net of discount, payable to the seller in connection with the EOGP assets. We paid the second and final installments during January 2017 and 2018, respectively. See "Note 3—Acquisition" for further discussion.
(2) Contribution from ENLC in connection with the acquisition of the EOGP assets. See "Note 3—Acquisition" for further discussion.

(17) Other Information

The following tables present additional detail for other current assets and other current liabilities, which consists of the following (in millions):

Other Current Assets:	**December 31, 2018**	**December 31, 2017**
Natural gas and NGLs inventory	$ 41.3	$ 30.1
Secured term loan receivable from contract restructuring, net of discount of $1.1	19.4	—
Prepaid expenses and other	12.1	9.6
Natural gas and NGLs inventory, prepaid expenses, and other	$ 72.8	$ 39.7

Other Current Liabilities:	**December 31, 2018**	**December 31, 2017**
Accrued interest	$ 37.3	$ 35.4
Accrued wages and benefits, including taxes	37.2	30.4
Accrued ad valorem taxes	28.1	27.8
Capital expenditure accruals	50.6	48.8
Onerous performance obligations	9.0	15.2
Other	84.5	64.8
Other current liabilities	$ 246.7	$ 222.4

(18) Subsequent Events

The Merger

On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. As a result of the Merger:

- Each issued and outstanding ENLK common unit (except for ENLK common units held by ENLC and its subsidiaries) has been converted into the right to receive 1.15 ENLC common units.

- Our general partner's incentive distribution rights in ENLK have been eliminated.

- The Series B Preferred Units will continue to be issued and outstanding following the Merger, except that certain terms of the Series B Preferred Units have been modified pursuant to an amended partnership agreement of ENLK. See "Note 8—Partners' Capital" for additional information regarding the modified terms of the Series B Preferred Units.

- ENLC issued to Enfield, the current holder of the Series B Preferred Units, for no additional consideration, ENLC Class C Common Units equal to the number of Series B Preferred Units held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC. For each additional Series B Preferred Unit issued by ENLK in quarterly in-kind distributions, ENLC will issue an additional ENLC Class C Common Unit to the applicable holder of such Series B Preferred Unit. In addition, for each Series B Preferred Unit that is exchanged into an ENLC common unit, an ENLC Class C Common Unit will be canceled.

- The Series C Preferred Units and all of ENLK's senior notes continue to be issued and outstanding following the Merger.

- All unit-based awards issued and outstanding immediately prior to the effective time of the Merger under the GP Plan have been converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting of terms of applicable awards related to the performance of ENLC.

- ENLC assumed the outstanding debt under the Term Loan and ENLK became a guarantor thereof.

Consolidated Credit Facility

We refinanced our existing revolving credit facilities at ENLK and ENLC. As of December 31, 2018, we had a $1.5 billion facility at ENLK and a $250.0 million facility at ENLC. Following the Merger, we have combined these credit facilities into one $1.75 billion credit facility at ENLC, with respect to which ENLK is a guarantor.

On December 11, 2018, ENLC entered into the Consolidated Credit Facility. The Consolidated Credit Facility became available for borrowings and letters of credit upon closing of the Merger. At the closing of the Merger, ENLK became a guarantor under the Consolidated Credit Facility.

The Consolidated Credit Facility permits ENLC to borrow up to $1.75 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility.

The Consolidated Credit Facility includes procedures for additional financial institutions to become lenders, or for any existing lender to increase its revolving commitment thereunder, subject to an aggregate maximum of $2.25 billion for all commitments under the Consolidated Credit Facility.

The Consolidated Credit Facility will mature on January 25, 2024, unless ENLC requests, and the requisite lenders agree, to extend it pursuant to its terms. The Consolidated Credit Facility contains certain financial, operational, and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenants include (i) maintaining a ratio of consolidated EBITDA (as defined in the Consolidated Credit Facility, which term includes projected EBITDA from certain capital expansion projects) to consolidated interest charges of no less than 2.50 to 1.0 at all times prior to the occurrence of an investment grade event (as defined in the Consolidated Credit Facility) and (ii) maintaining a ratio of consolidated indebtedness to consolidated EBITDA of no more than 5.00 to 1.00. If ENLC consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, ENLC can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters.

Borrowings under the Consolidated Credit Facility bear interest at ENLC's option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.125% to 2.00%) 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 (ranging from 0.125% to 1.00%). The applicable margins vary depending on ENLC's debt rating. Upon breach by ENLC of certain covenants governing the Consolidated Credit Facility, amounts outstanding under the Consolidated Credit Facility, if any, may become due and payable immediately.

At December 31, 2018, ENLC was in compliance with and expects to be in compliance with the covenants in the Consolidated Credit Facility for at least the next twelve months.

Transfer of EOGP interest

On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership in exchange for 55,827,221 ENLK common units. EOGP is now a wholly-owned subsidiary of the Operating Partnership.

Reporting Segments

Effective January 1, 2019, we will report financial performance in four operating segments: Oklahoma, Permian, Louisiana and North Texas. Crude and Condensate operations will be combined regionally with natural gas and NGL operations in Oklahoma and Permian, and ORV operations will be included in the Louisiana segment.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of EnLink Midstream GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2018), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

Effective January 1, 2018, we adopted ASC 606. The adoption of this accounting standard had no impact on our operating income, results of operations, financial condition, or cash flows. While the adoption of ASC 606 did not materially affect our internal control over financial reporting, we did implement certain changes to our related revenue recognition control activities, including changes to our policies related to the revenue recognition model, training, ongoing contract review requirements, and gathering of information to comply with disclosure requirements. Furthermore, there has been no change in our internal control over financial reporting that occurred in the year ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Internal Control Over Financial Reporting

See “Item 8. Financial Statements and Supplementary Data—Management’s Report on Internal Control over Financial Reporting.”

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

We are managed by the board of directors and executive officers of EnLink Midstream GP, LLC, our general partner. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or to participate directly or indirectly in our management or operations. Our operational personnel are employees of the Operating Partnership. References to our officers, directors, and employees are references to the officers, directors, and employees of our general partner or the Operating Partnership.

Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are entered into and specified as nonrecourse to our general partner. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

The following table shows information for the members of the board of directors (the "Board")and the executive officers of our general partner immediately following the consummation of the Merger. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with EnLink Midstream GP, LLC
Michael J. Garberding	50	President, Chief Executive Officer, and Director
Eric D. Batchelder	47	Executive Vice President and Chief Financial Officer
Benjamin D. Lamb	39	Executive Vice President and Chief Operating Officer
Alaina K. Brooks	44	Executive Vice President, Chief Legal and Administrative Officer, Secretary, and Director
Barry E. Davis	57	Director and Executive Chairman

Michael J. Garberding, President, Chief Executive Officer, and Director, joined our general partner in February 2008 and was appointed as a director of our general partner in January 2018. Mr. Garberding was appointed President and Chief Executive Officer effective January 2, 2018. Previously, Mr. Garberding served in the role of President and Chief Financial Officer from September 2016 to January 2018, in the role of Executive Vice President and Chief Financial Officer from January 2013 to September 2016, and in the role of Senior Vice President and Chief Financial Officer from August 2011 to January 2013. Mr. Garberding previously led our finance and business development organization from 2008 to 2011. Mr. Garberding has over 25 years of experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Master of Business Administration from the University of Michigan in 1999 and his Bachelor of Business Administration in accounting from Texas A&M University in 1991. Mr. Garberding is currently a member of the American Heart Association. Mr. Garberding was selected to serve as a director due to, among other factors, his accounting and financial experience, his leadership skills, and his experience in the midstream industry.

Eric D. Batchelder, Executive Vice President and Chief Financial Officer, joined our general partner in January 2018. Prior to joining our general partner,Mr. Batchelder served five years as Managing Director, Energy Investment Banking at RBC Capital Markets. At RBC, he was responsible for maintaining key client relationships, strategic planning, and business development efforts for the bank's midstream energy advisory business in the United States. Previously, Mr. Batchelder spent 10 years at Goldman Sachs & Co. Prior to that, he spent seven years at Arthur Andersen LLP. Mr. Batchelder has over 15 years of strategic M&A and capital markets experience in the energy sector. Mr. Batchelder is a Certified Public Accountant. He earned a Bachelor of Arts in economics from Middlebury College, a Master of Science in professional accounting from the University of Hartford, and a Master of Business Administration from The Tuck School of Business at Dartmouth.

Benjamin D. Lamb, Executive Vice President and Chief Operating Officer, joined our general partner in December 2012. Mr. Lamb assumed his current role in June 2018, having previously served in a number of leadership roles for our general partner, most recently as Executive Vice President—North Texas and Oklahoma from February 2018 to June 2018 and previously as Executive Vice President—Corporate Development, Senior Vice President—Finance and Corporate Development, and Vice President—Finance from December 2012 to February 2018. Prior to joining our general partner, Mr. Lamb served as a Principal at the investment banking firm Greenhill & Co., which he joined in 2005. In that role, he focused on the evaluation and execution of mergers, acquisitions, and restructuring transactions for clients primarily in the midstream energy, power, and utility industries. Prior to joining Greenhill, he served as an investment banker at UBS Investment Bank in its Mergers and Acquisitions Group and in its Global Energy Group, and at Merrill Lynch in its Global Energy and Power Group. Mr. Lamb received his Bachelor of Business Administration from Baylor University in 2000.

Alaina K. Brooks, Executive Vice President, Chief Legal and Administrative Officer, Secretary, and Director, joined our general partner in 2008 and was appointed as a Director of our general partner on January 25, 2019. Ms. Brooks has served in several legal roles forour general partner, most recently as Senior Vice President, General Counsel and Secretary from September 2014 until June 2018 and as Deputy General Counsel until September 2014. In Ms. Brooks' current role, she serves on our Executive Leadership Team and leads the legal, regulatory, public and industry affairs, environmental health and safety, and human resources functions. Before joining our general partner in 2008, Ms. Brooks practiced law at Weil, Gotshal & Manges LLP and Baker Botts L.L.P., where she counseled clients on matters of complex commercial litigation, risk management, and taxation. Ms. Brooks is a licensed Certified Public Accountant and holds a Juris Doctor from Duke University School of Law and Bachelor of Science and Master of Science in accounting from Oklahoma State University. Ms. Brooks was selected to serve as a director due to, among other factors, her legal and human resources experience in the midstream energy industry.

Barry E. Davis, Director and Executive Chairman, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which resulted in the formation of Crosstex Energy, Inc. Mr. Davis was appointed to Executive Chairman effective January 2, 2018. Previously, Mr. Davis served as Chairman and Chief Executive Officer from September 2016 until January 1, 2018 and as President and Chief Executive Officer from our formation until September 2016. Mr. Davis has served as a director since the initial public offering of Crosstex Energy, L.P. in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a Bachelor of Business Administration in Finance from Texas Christian University. Mr. Davis's leadership skills and experience in the midstream natural gas industry, among other factors, led the Board to conclude that he should serve as a director and Executive Chairman.

Independent Directors

Following the Merger, we do not have securities listed on the NYSE or any other national securities exchange and are no longer subject to the rules of the NYSE, including rules that require independent directors on the Board. As a result, as of immediately following the Merger, we do not have any independent directors on the Board.

Using the NYSE standards for determining independence, the Board determined that, in 2018, Mary P. Ricciardello, who served on the Board until the closing of the GIP Transaction, and Leldon E. Echols, Kyle D. Vann, and Scott A. Griffiths, each of whom served on the Board until the closing of the Merger, qualified as independent directors under NYSE standards. Prior to the closing of the GIP Transaction, Ms. Ricciardello served as an independent director on the Audit Committee of the Board (the "Audit Committee"). Prior to the closing of the Merger, Mr. Echols served as an independent director on the Audit Committee, Mr. Griffiths served as an independent director on the Compensation Committee of the Board (the "Compensation Committee"), the Audit Committee, and the Conflicts Committee of the Board (the "Conflicts Committee"), and Mr. Vann served as an independent director on the Audit Committee and the Conflicts Committee.

Board Committees

Following the Merger, we do not have securities listed on the NYSE or any other national securities exchange and are no longer subject to the rules of the NYSE, including rules that require an audit committee. Therefore, following the Merger, the Board does not have any standing committees, including an audit committee. The Audit Committee (the "Manager Audit Committee") of the board of directors of the manager of ENLC (the "Manager Board"), which is comprised of James C. Crain, Leldon E. Echols, and Kyle D. Vann, is responsible for overseeing our financial reporting, internal controls, and audit functions, and is directly responsible for the appointment, retention, compensation, and oversight of the work of our independent auditors. The members of the Manager Audit Committee qualify as "independent" under special standards established by the Securities and Exchange Commission ("SEC") for members of audit committees, and the Manager Audit Committee includes at least one member who is determined by the Manager Board to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Leldon E. Echols is an independent director of the Manager Board who has been determined by the Manager Board to be an audit committee financial expert. Unitholders should understand that this designation is a disclosure requirement of the SEC related to the experience and understanding of directors with respect to certain accounting and auditing matters. The designation does not impose on such directors any duties, obligations, or liabilities that are greater than are generally imposed on them as members of the Manager Audit Committee and the Manager Board, and the designation of a director as audit committee financial expert pursuant to this SEC requirement does not affect the duties, obligations, or liabilities of any other member of the Manager Audit Committee or the Manager Board.

Code of Ethics

Our general partner has adopted a Code of Business Conduct and Ethics (the “Code of Ethics”) applicable to all of our employees, officers, and directors. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of the Code of Ethics is available to any person, free of charge, within the “Governance Documents” subsection of the “Corporate Governance” section of the investors section of our website at www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we or our general partner grants any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our general partner’s executive officers and directors, we will disclose the nature of such amendment or waiver on our website. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Section 16(a)—Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers, and beneficial owners of more than 10% of our common units to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Forms 3, 4, and 5 reports furnished to us and written representations from our directors and executive officers, we believe that during 2018, all of our directors, executive officers, and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them, other than one Form 4 for McMillan (Mac) Hummel, which form was due on July 20, 2018 but was filed ten days late, and one Form 4 for Goldman Sachs Group Inc., which form was due on August 27, 2018 but was filed 13 days late.

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of us. However, our general partner performs services for us and, prior to the Merger, was reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer, and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Pursuant to the partnership agreement, our general partner determined the expenses that were allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Item 11. Executive Compensation

Compensation Committee Report

As discussed below, our named executive officers are also named executive officers of ENLC, and the compensation of the named executive officers disclosed herein reflects total compensation for services with respect to ENLC and all subsidiaries of ENLC, including ENLK. The Governance and Compensation Committee (the “Manager Committee”) of the Manager Board evaluates and makes recommendations to the Manager Board regarding ENLC’s named executive officer compensation. In addition, effective as of the Merger, the Board is composed entirely with named executive officers of ENLK. Due to the foregoing, the Board does not have a standing compensation committee and, instead, the Manager Committee evaluates and makes recommendations to the Board regarding ENLK’s named executive officer compensation and has otherwise assumed and will discharge the duties previously discharged by the former Compensation Committee of the Board (the “Compensation Committee”).

Kyle D. Vann and Leldon E. Echols, who serve on the Manager Committee, are independent directors of the Manager Board in accordance with NYSE standards. Each of the Manager Committee and the Board has reviewed and discussed with management the following section titled “Compensation Discussion and Analysis.” Based upon their respective review and discussions, the Manager Committee has recommended to the Board, and the Board has authorized, that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

By the Members of the Manager Committee:

Kyle D. Vann (Chairman)

William J. Brilliant

Leldon E. Echols

By the Members of the Board:

Barry E. Davis

Michael J. Garberding

Alaina K. Brooks

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis provides an overview of the philosophy and objectives of our executive compensation program. It explains how compensation decisions are linked to performance as compared to our strategic goals and defined targets under the elements of the compensation program. These goals and targets are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance.

Overview

We do not directly employ any of the persons responsible for managing our business. EnLink Midstream GP, LLC, our general partner, manages our operations and activities, and the Board and officers make decisions on our behalf. For 2018, the compensation of the named executive officers of EnLink Midstream GP, LLC was determined by the Board upon the recommendation of the Compensation Committee. Historically, our named executive officers also have served as named executive officers of ENLC, and the compensation of the named executive officers discussed below reflects total compensation for services with respect to ENLC and all subsidiaries of ENLC. For the periods prior to the Merger, we paid or reimbursed all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner determined the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. For the periods prior to the Merger, ENLC paid a monthly fee to EnLink Midstream GP, LLC to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to ENLK, we estimate that such officers devoted the following percentage of their time to the business of ENLK and ENLC for 2018:

Executive Officer	Percentage of Time Devoted to Business of ENLK	Percentage of Time Devoted to Business of ENLC
Michael J. Garberding	50%	50%
Benjamin D. Lamb (1)	70%	30%
Barry E. Davis	60%	40%
Eric Batchelder	60%	40%
Alaina K. Brooks (1)	70%	30%
McMillan Hummel (2)	90%	10%

(1) In June 2018, Mr. Lamb was promoted to Executive Vice President and Chief Operating Officer and Ms. Brooks was promoted to Executive Vice President, Chief Legal and Administrative Officer, and Secretary.
(2) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

Compensation Philosophy and Principles

Our executive compensation program is designed to attract, retain, and motivate highly qualified executives and align their individual interests with the interests of our unitholders. For periods prior to the Merger, it was theCompensation Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board to approve and adopt these programs. The Manager Committee has undertaken these responsibilities for periods after the Merger and with respect to making recommendations to the Board and the Manager Board. The total compensation of each of our executives is comprised of 60% equity-based awards issued under our long-term incentive plan, 20% annual bonus awarded under the Short-Term Incentive Program (the "STI Program"), and 20% base salary.

The applicable compensation committee considers the following principles in determining the total compensation of the named executive officers:

- Base salary, short-term incentives and long-term incentives should be competitive with the market in which we compete for executive talent in order to attract, retain, and motivate highly qualified executives;
- Equity-based awards under the long-term incentive plans should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives and to ensure all executives have a meaningful equity stake in us. Equity-based awards foster a culture of ownership and are a way to align the interests of executives with those of our unitholders;
- The compensation program should be sufficiently flexible to address special circumstances, including retention initiatives specifically targeted to retain highly qualified executives during challenging times; and
- The compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology

Prior to the Merger, the Compensation Committee annually reviewed our executive compensation program and each individual element of compensation. For periods after the Merger, the responsibility for conducting this review will be undertaken by the Manager Committee. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face, and individual contributions to us and our general partner. For 2018, theCompensation Committee recommended to the Board adjustments to the compensation program and to each individual element as determined necessary to achieve our goals. TheCompensation Committee retained compensation expertise to assist in its 2018review and to provide input regarding the 2018 compensation program and each individual element.

Role of Compensation Consultant

For 2018, the Compensation Committee retained Meridian Compensation Partners, LLC ("Meridian") as its independent compensation consultant to conduct a compensation review and advise the Compensation Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of our general partner. In particular, Meridian assisted the Compensation Committee's decision making with respect to named executive officers and director compensation matters, including providing advice on our 2018 executive pay philosophy, compensation peer group, incentive plan design and employment agreement design, providing competitive market studies, and informing the Compensation Committee about emerging best practices and changes in the regulatory and governance environment. Meridian provided information to the Compensation Committee regarding the compensation programs of ENLK and ENLC for 2018. Meridian's work for the Compensation Committee did not raise any conflicts of interest in 2018.

Role of Peer Group and Benchmarking

For 2018, the Compensation Committee and Meridian collaborated to identify the following companies as our peer companies: Boardwalk Pipeline Partners, L.P., Buckeye Partners, L.P., Cheniere Energy, Inc., Enable Midstream Partners, LP, Energy Transfer Partners, L.P., Genesis Energy, L.P., HollyFrontier Corp., Magellan Midstream Partners, L.P., NuStar Energy L.P., ONEOK Inc., Targa Resources Corp., Andeavor (formerly Tesoro Corp.), and The Williams Cos. Inc. (the "Peer Group"). We believe the Peer Group is representative of the industry in which we operate. The individual companies were chosen based on a number of factors, including each company's relative size/market capitalization, relative complexity of its business, similar organizational structure, competition for similar executive talent, and the roles and responsibilities of its named executive officers. Prior to the closing of the Merger, the Compensation Committee considered the Peer Group companies annually, and historically there have been few changes from year to year. Companies typically have been added or removed from the Peer Group as the result of a change in organizational structure or relative size/market capitalization as compared to us.

When evaluating annual compensation levels for each named executive officer, the Compensation Committee, with the assistance of Meridian, reviewed compensation surveys and publicly available compensation data for executives in our Peer Group, including data on base salaries, annual bonuses, and long-term equity incentive awards. The Compensation Committee then used that information to determine individual elements of compensation for the named executive officers in the context of their roles, levels of responsibility, accountability, and decision-making authority within our organization and in the context of company size relative to the other Peer Group members. In addition, Meridian has provided guidance on current industry trends and best practices to the Compensation Committee relating to all aspects of executive compensation.

While compensation surveys and Peer Group data were considered, the Compensation Committee did not attempt to set compensation elements to meet specific benchmarks. Accordingly, other subjective factors were also considered in setting compensation elements, including, but not limited to, (i) effort and accomplishment on a group and individual basis, (ii) challenges faced and challenges overcome, (iii) unique skills, (iv) contribution to the management team, (v) succession planning and retention of our executive officers, and (vi) the perception of both the Board and the Compensation Committee of our performance relative to expectations and actual market/business conditions.

Elements of Compensation

For fiscal year 2018, the principal elements of compensation for the named executive officers were the following:

- base salary;
- annual bonus awards;
- long-term incentive plan equity awards;
- retirement and health benefits; and
- severance and change of control benefits.

For 2018, the Compensation Committee reviewed and made recommendations to the Board regarding the mix of compensation, both among short- and long-term compensation and cash and non-cash compensation, to establish structures that it believed were appropriate for each of the named executive officers. We have believed that the mix of base salary, annual bonus awards, long-term incentive plan equity awards, retirement and health benefits, severance and change of control benefits and perquisites and other compensation fit our overall compensation objectives. We have believed this mix of compensation provides opportunities to align and drive performance of our named executive officers in support of our strategic objectives and to attract, retain, and motivate highly qualified talent with the skills and competencies that we require.

Base Salary. For 2018, the Compensation Committee recommended to the Board the base salaries for the named executive officers based on the historical salaries for services rendered to us and our affiliates, Peer Group data provided by Meridian, compensation surveys, and performance and responsibilities of the named executive officers. The base salaries approved by the Board and paid to our named executive officers for fiscal year 2018 (and payable for fiscal 2019 based on the Manager Committee's recommendation and the approval of the Board and the Manager Board) are as follows:

	Prior Salary	Base Salary Effective For 2019	Percent Increase (Decrease)
Michael J. Garberding	$ 650,000	$ 675,000	3.8 %
Benjamin D. Lamb (1)	$ 475,000	$ 491,625	3.5 %
Barry E. Davis	$ 525,000	$ 425,000	(19.0)%
Eric D. Batchelder	$ 435,000	$ 450,225	3.5 %
Alaina K. Brooks (1)	$ 425,000	$ 439,875	3.5 %
McMillan Hummel (2)	$ 435,000	$ —	(100.0)%

(1) In June 2018, Mr. Lamb was promoted to Executive Vice President and Chief Operating Officer and Ms. Brooks was promoted to Executive Vice President, Chief Legal and Administrative Officer, and Secretary.
(2) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

Bonus Awards. Prior to the closing of the Merger, the Board and the Manager Board (collectively, the "STI Board") along with the Compensation Committee and the Manager Committee (collectively, the "Legacy Compensation Committees") oversaw the STI Program. For periods after the Merger, including with respect to amounts paid in 2019 related to 2018 bonus awards under the STI Program, the responsibility of overseeing the STI Program has been undertaken by the STI Board and Manager Committee. All employees, including named executive officers, are eligible to receive annual bonuses under the STI Program. Bonuses awarded to employees and named executive officers under the STI Program are based on the achievement of certain metrics established to measure success and are subject to the discretion of, as applicable, the STI Board and the Legacy Compensation Committees or the Manager Committee (as applicable, the "STI Committee").

The metrics employed by the STI Program contemplate that bonuses may be earned based primarily upon the achievement of certain core goals (collectively, the "Primary Bonus Components"), which may change from year-to-year. As reflected in the table below, a separate weighting is applied for each of the Primary Bonus Components. The Primary Bonus Components for 2018 and associated information are as follows:

Component	Description	Weighting
Financial	Adjusted EBITDA and cost management to maximize financial performance	50% Adjusted EBITDA 10% Cost management
Growth	Timely and cost-effective growth pursuant to the Strategic Plan and overarching direction	10%
Operational	Efficient use of systems, assets and equipment for meeting contractual obligations, driving customer service and maximizing cash flow	10%
People	Train and develop our workforce	10%
Environmental and Safety	Prevent safety incidents and improve safety compliance, operations, and training	10%

Each year, performance under the Primary Bonus Components will be measured, as applicable, on an interpolated "threshold/target/maximum" basis. Each year, a range of bonus pool values for the STI Program will be established to account for various levels of performance under the Primary Bonus Components, as applied on a weighted average basis. These bonus pool values are a framework and are subject to the application of the discretion of the STI Board and the STI Committee to determine the bonus amounts that are ultimately payable under the STI Program, including to the named executive officers, as further described below.

The STI Committee and the STI Board, with input from management, set the annual weightings for each Primary Bonus Component and any additional weightings that apply with respect to the features comprising a particular Primary Bonus Component. In addition, the STI Committee and the STI Board, with input from management, set, as applicable, the "threshold/target/maximum" standard that applies to the Primary Bonus Components. This standard is based on a number of considerations, including, but not limited to, reasonable market expectations, internal company forecasts, available growth opportunities, company performance, leading indicators, and industry standards.

The STI Board, based on recommendations of the STI Committee, initially establishes the target bonus awards that may be earned and ultimately determines the final bonus amounts, if any, that are payable under the STI Program for the named executive officers. Initial bonus award amounts for consideration by the STI Committee and the STI Board for the named executive officers will be established by multiplying (x) the relevant named executive officer's target bonus percentage by (y) the relevant named executive officer's base salary earnings (subject to certain adjustments to account for, among other things, mid-year changes in base salary or a mid-year hiring or termination) by (z) an achievement percentage for the relevant year.

The STI Committee believes that a portion of executive compensation for named executive officers must remain discretionary. Therefore, the STI Program contemplates that the STI Committee and the STI Board retain discretion with respect to target bonus awards and the final bonus amounts for named executive officers. In this regard, the STI Committee may exercise such discretion to recommend to the STI Board a reduction or increase of the target bonus or the final bonus amounts for a particular named executive officer to reward or address extraordinary individual performance, challenges, and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities, and external competition or opportunities.

The final amount of bonus for each named executive officer was approved by the STI Board based upon the STI Committee's recommendation and assessment of whether such officer met his or her performance objectives established at the beginning of the performance period. These performance objectives included the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer, and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives were reviewed and evaluated by the STI Committee as a whole. All named executive officers met or exceeded their minimum personal performance objectives for 2018. Accordingly, the STI Committee and the STI Board awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	**2018 Bonus (as a % of Base Salary)**	**2018 Bonus Amount ($)**
Michael J. Garberding	100 %	155 %	1,009,247
Benjamin D. Lamb (1)	100 %	140 %	665,733
Barry E. Davis	95 %	149 %	784,367
Eric D. Batchelder	90 %	129 %	560,771
Alaina K. Brooks (1)	90 %	110 %	468,087
McMillan Hummel (2)	90 %	83 %	362,474

(1) In June 2018, Mr. Lamb was promoted to Executive Vice President and Chief Operating Officer and Ms. Brooks was promoted to Executive Vice President, Chief Legal and Administrative Officer, and Secretary. In association with a promotion, the target bonus percentage for Mr. Lamb increased from 90% to 100% and the target bonus percentage for Ms. Brooks increased from 60% to 90%.

(2) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

For 2018, target adjusted EBITDA was based upon a standard of reasonable market expectations and our performance and varies from year to year. For 2018, our adjusted EBITDA levels for bonuses were $955.4 million for minimum threshold bonuses, $1,022.9 million for target bonuses, and $1,105.8 million for maximum bonuses. For 2018, the STI Program provided for named executive officers to receive bonus payouts of 45% to 50% of base salary at the minimum threshold, 90% to 100% of base salary at the target level, and 180% to 200% of base salary at the maximum level.

Long-Term Incentive Plans. Our named executive officers and outside directors participated in the EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan") and the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 Plan"). Finally, certain directors, officers, and employees participate in the EnLink Midstream, LLC 2009 Long-Term Incentive Plan (the "2009 Plan").

Prior to the Merger, the Board, upon the recommendation of the Compensation Committee, approved the grants of equity awards under the GP Plan to our named executive officers. No additional grants of equity awards will be made under the GP Plan for periods after the Merger. The Compensation Committee has believed that equity awards should comprise a significant portion of a named executive officer's total compensation. A number of factors have been considered when determining grants to each individual named executive officer including but not limited to: compensation surveys, Peer Group data, the named executive officer's individual performance, company performance, market conditions, succession planning, retention, and other factors as determined by the Compensation Committee and/or the Board.

A discussion of each plan follows:

EnLink Midstream GP, LLC Long-Term Incentive Plan. EnLink Midstream GP, LLC adopted the GP Plan for employees, consultants, and independent contractors of EnLink Midstream GP, LLC and its affiliates and outside directors of our Board who perform services for us. For the periods prior to the Merger, the GP Plan was administered by the Compensation Committee and permitted the grant of awards, which may be awarded in the form of restricted incentive units or options.As indicated above, no additional grants of equity awards will be made under the GP Plan for periods after the Merger. On May 9, 2013, our unitholders approved the amendment and restatement of the GP Plan, which increased the number of common units representing limited partner interests in us authorized for issuance under the GP Plan by 3,470,000 common units to an aggregate of 9,070,000 common units and made certain other technical amendments. Effective April 6, 2016, our unitholders approved the amendment and restatement of the GP Plan, which increased the number of common units representing limited partner interests in us authorized for issuance under the GP Plan by 5,000,000 common units to an aggregate of 14,070,000 common units and other technical changes. Of the 14,070,000 common units that may be awarded under the GP Plan as of December 31, 20183,418,034 common units remained eligible for future grants The long-term compensation structure of the GP Plan was intended to align the performance of participants with long-term performance for our unitholders. In addition, the 3,416,046 common units (denominated for purposes of this sentence as ENLC common units) that remained eligible for future grants under the GP Plan immediately prior to the effective time of the Merger (the "Rollover Units") were included among the ENLC common units available for grant under the 2014 Plan. In determining this number of the Rollover Units (i.e., the 3,416,046 ENLC common units specified above), certain assumptions were made regarding the number of units issuable pursuant to any awards under the GP Plan that were outstanding immediately prior to the effective time of the Merger. For instance, it was assumed that performance metrics, as and when applicable under such awards, would be satisfied in the future at their maximum levels, thereby resulting in the greatest amount of units being issued pursuant to such awards.

Effective as of the closing of the Merger, each unit-based award issued and outstanding immediately prior to the effective time of the Merger under the GP Plan has been converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting terms for any applicable awards related to the performance of ENLC and ENLK (as further described below). In addition, as of the closing of the Merger (i) ENLC assumed all obligations in respect of the GP Plan, and (ii) the Manager Committee (and Manager Board when applicable) became responsible for the administration of the GP Plan.

The GP Plan will automatically expire on March 3, 2026. For periods after the effective time of the Merger, theManager Board, in its discretion, may terminate or amend the GP Plan at any time. The Manager Board or the Manager Committee also has the right to alter or amend the GP Plan or any part of the GP Plan from time to time. In addition, the Manager Committee may generally amend the terms of any outstanding award under the GP Plan at any time. However, the above actions may not be taken by the Manager Board or the Manager Committee without the participant's consent if such actions would materially reduce the benefits of a participant under a previously granted award. It is anticipated that no future awards will be granted under the GP Plan.

The following forms of awards were awarded under the GP Plan:

- *Options.* For periods preceding the effective time of the Merger, the GP Plan permits the grant of options coveringcommon units. These options are rights to purchase a specified number of our common units at a specified price. The exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options granted become exercisable on such terms as the Compensation Committee determined. Under no circumstances will distributions or DERs (as defined below) be granted or made with respect to option awards. For periods after the effective time of the Merger, the ENLC common units to be delivered upon the exercise of an option may be common units acquired in the open market, common units already owned by any affiliate of us or ENLC, common units acquired directly from any affiliate of us orENLC or from any other person, or any combination of the foregoing.

- *Restricted Incentive Units.* For periods preceding the effective time of the Merger, the GP Plan permits the grant of restricted incentive units. These awards of restricted incentive units are rights that entitle the grantee to receive cash, common units, or a combination of cash and common units of ENLK upon the vesting of such restricted incentive units. The Compensation Committee determined the terms, conditions, and limitations applicable to any awards of restricted incentive units. Awards of restricted incentive units have a vesting period established in the sole discretion of the Compensation Committee, which could include, without limitation, vesting upon the achievement of specified performance goals. For periods after the effective time of the Merger, the ENLC common units to be delivered upon the vesting of restricted incentive units may be common units acquired in the open market, common units already owned by any affiliate of us or ENLC, common units acquired by our general partner directly from any affiliate of us or ENLC or from any other person, or any combination of the foregoing. The Compensation Committee, in its discretion, could grant tandem distribution equivalent rights ("DERs") with respect to restricted incentive units, which entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made by us with respect to a common unit during the period the DER is outstanding. The Compensation Committee could provide, in its discretion, that the DERs will be subject to the same forfeiture and other restrictions as a restricted incentive unit and, if so restricted, such distributions will be held, without interest, until the restricted incentive unit vests or is forfeited with the distribution being paid or forfeited at the same time, as the case may be. We intended for the issuance of the common units upon vesting of the restricted incentive units under the GP Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, GP Plan participants do not pay any consideration for the common units they receive, and we have not received remuneration for the units issuable in respect of restricted incentive unit awards.

Upon a change of control for purposes of the GP Plan and subject to the terms and conditions of the applicable award agreements thereunder, the outstanding options may become exercisable and the outstanding restricted incentive units may become vested upon the change of control or a qualifying termination of employment thereafter. The closing of the GIP Transaction constituted a change of control for such purposes, and the terms and conditions of the performance-based restricted incentive unit awards provided for accelerated vesting upon such change of control. However, certain officers waived the accelerated vesting of their performance-based restricted incentive unit awards, such that, the waived awards remain outstanding and subject to vesting based on the performance metrics and termination conditions specified in the applicable awards (as amended in connection with such waiver).

EnLink Midstream, LLC Long-Term Incentive Plans

2014 Plan. Employees, non-employee directors, and other individuals who provide services to us or our affiliates may be eligible to receive awards under the 2014 Plan; however, the Manager Committee determines which eligible individuals receive awards under the 2014 Plan, subject to the Manager Board's approval of awards to our named executive officers. The 2014 Plan is administered by the Manager Committee and permits the grant of cash and equity-based awards, which may be awarded in the form of options, restricted unit awards, restricted incentive units, unit appreciation rights ("UARs"), DERs, unit awards, cash awards, and performance awards. At the time of adoption of the 2014 Plan, 11,000,000 common units representing limited liability company interests in ENLC were initially reserved for issuance pursuant to awards under the 2014 Plan. Common units subject to an award under the 2014 Plan that are canceled, forfeited, exchanged, settled in cash, or otherwise terminated, including withheld to satisfy exercise prices or tax withholding obligations, will again become available for delivery pursuant to other awards under the 2014 Plan. Of the 11,000,000 common units that may be awarded under the 2014 Plan, 6,746,890 common units remain eligible for future grants as of December 31, 2018. The long-term compensation structure of the 2014 Plan is intended to align the performance of participants with long-term performance for ENLC's unitholders. The 2014 Plan was subsequently amended and restated (i) effective as of January 20, 2019 to increase the number of common units reserved for issuance thereunder to 17,700,000 units, and (ii) effective as of January 25, 2019 to reflect certain transactions described in the Merger Agreement including the inclusion of the Rollover Units among the common units available for issuance under the 2014 Plan.

The 2014 Plan, as currently amended and restated, will automatically expire on December 30, 2028. The Manager Board may amend or terminate the 2014 Plan at any time, subject to any requirement of unitholder approval required by applicable law, rule, or regulation. The Manager Committee may generally amend the terms of any outstanding award under the 2014 Plan at any time. However, no action may be taken by the Manager Board or the Manager Committee under the 2014 Plan that would materially and adversely affect the rights of a participant under a previously granted award without the participant's consent.

The following forms of awards may be awarded under the 2014 Plan:

- *Options.* The 2014 Plan permits the grant of options covering common units. These options are rights to purchase a specified number of common units of ENLC at a specified price. The exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options granted will become exercisable on such terms as the Manager Committee determines. The Manager Committee will also determine the time or times at which, and the circumstances under which, an option may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, form of consideration payable in settlement, method by or forms in which common units will be delivered to participants, and whether or not an option will be in tandem with a UAR award. Under no circumstances will distributions or DERs be granted or made with respect to option awards. An option granted to an employee may consist of an option that complies with the requirements of Section 422 of the Internal Revenue Code (the "IRC"), referred to in the 2014 Plan as an "incentive unit option." In the case of an incentive unit option granted to an employee who owns (or is deemed to own) more than 10% of the total combined voting power of all classes of units, the exercise price of the option must be at least 110% of the fair market value per common unit on the date of grant and the term of the option cannot exceed five years from the date of grant.

- *Unit Appreciation Rights or UARs.* The 2014 Plan permits the grant of UARs. A UAR is a right to receive an amount equal to the excess of the fair market value of one common unit of ENLC on the date of exercise over the grant price of the UAR. UARs will be exercisable on such terms as the Manager Committee determines. The Manager Committee will also determine the time or times at which and the circumstances under which a UAR may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, method of settlement, form of consideration payable in settlement, method by or forms in which common units will be delivered or deemed to be delivered to participants, whether or not a UAR shall be in tandem with an option award, and any other terms and conditions of any UAR. UARs may be either freestanding or in tandem with other awards. Under no circumstances will distributions or DERs be granted or made with respect to UAR awards.

- *Restricted Units.* The 2014 Plan permits the grant of restricted units. A restricted unit is a grant of a common unit of ENLC subject to a substantial risk of forfeiture, restrictions on transferability, and any other restrictions determined by the Manager Committee. The Manager Committee may provide, in its discretion, that the distributions made by ENLC with respect to the restricted units will be subject to the same forfeiture and other restrictions as the restricted unit and, if so restricted, such distributions will be held, without interest, until the restricted unit vests or is forfeited with the unit distribution right being paid or forfeited at the same time, as the case may be. In addition, the Manager Committee may provide that such distributions be used to acquire additional restricted units for the participant. Under no circumstances will DERs be granted or made with respect to restricted unit awards.

- *Restricted Incentive Units.* The 2014 Plan permits the grant of restricted incentive units. These awards of restricted incentive units are rights that entitle the grantee to receive cash, common units of ENLC, or a combination of cash and common units of ENLC upon the vesting of such restricted incentive units. Restricted incentive units may be subject to restrictions, including a risk of forfeiture, as determined by the Manager Committee. The Manager Committee may, in its sole discretion, grant DERs with respect to restricted incentive units. We intend for the issuance of the common units upon vesting of the restricted incentive units under the 2014 Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under the current policy, 2014 Plan participants will not pay any consideration for the common units they receive, and ENLC will receive no remuneration for the units.

- *Distribution Equivalent Rights or DERs.* The 2014 Plan permits the grant of DERs. DERs entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made with respect to an ENLC common unit during the period the right is outstanding. DERs may be granted as a stand-alone award or with respect to awards other than restricted units, options, or UARs. Subject to Section 409A of the IRC, payment of a DER issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the Manager Committee.

- *Unit Awards.* The 2014 Plan permits the grant of unit awards, which are common units of ENLC that are not subject to vesting restrictions.

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

- *Performance Awards.* The 2014 Plan permits the grant of performance awards. Performance awards represent a participant's right to receive an amount of cash, common units of ENLC, or a combination of both, contingent upon the annual attainment of specified performance measures within a specified period. The Manager Committee or, if applicable, the special committee that is responsible for overseeing performance awards that are intended to satisfy certain requirements of Section 162(m) of the IRC (the "Section 162(m) Committee"), will determine the applicable performance period, the performance goals and such other conditions that apply to each performance award. As a result of tax reform that became effective on January 1, 2018, grants of performance awards made after November 2, 2017 will no longer be eligible to qualify as qualified performance-based compensation under Section 162(m) of the IRC, such that, it will not be necessary to utilize the Section 162(m) Committee with respect to such awards. However, it may be possible for performance awards that were outstanding as of November 2, 2017 to continue to qualify as qualified performance-based compensation for such purposes so long as the awards are not modified in any material respect after such date (and assuming that the awards otherwise satisfy any transition relief guidance issued by the Internal Revenue Service). Section 162(m) of the IRC generally limits the deductibility for federal income tax purposes of annual compensation paid to certain top executives of a company to $1 million per covered employee in a taxable year (except to the extent such compensation qualifies as (among other things) qualified performance-based compensation as of November 2, 2017 (and such compensation is not materially modified), for purposes of Section 162(m) of the IRC). Prior to the payment of any compensation based on the achievement of performance goals applicable to performance awards that were outstanding as of November 2, 2017 and remain intended to provide qualified performance-based compensation under Section 162(m) of the IRC, the Section 162(m) Committee must certify in writing that the applicable performance goals and any of the material terms thereof were, in fact, satisfied. For all other performance awards, this certification will be undertaken by the Manager Committee.

Upon a change of control of us, our general partner, or ENLC and except as provided in the applicable award agreement, the Manager Committee may cause options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control of ENLC and except as provided in the award agreement, the Manager Committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement, or the other terms of such awards. The closing of the GIP Transaction constituted a change of control for such purposes, and the terms and conditions of the performance-based restricted incentive unit awards provided for accelerated vesting upon such change of control. However, certain officers waived the accelerated vesting of their performance-based restricted incentive unit awards, such that the waived awards remain outstanding and subject to vesting based on the performance metrics and termination conditions specified in the applicable awards (as amended in connection with such waiver).

EnLink Midstream 2009 Long-Term Incentive Plan. The EnLink Midstream, LLC 2009 Long-Term Incentive Plan (the “2009 Plan”) Plan provides for the award of options, restricted units, restricted incentive units, and other awards (collectively, “Awards”). It is anticipated that no future Awards will be granted under the 2009 Plan. The Manager Committee administers the 2009 Plan and has the authority to grant waivers of the applicable plan terms, conditions, restrictions, and limitations. As of December 31, 2018, no common units are reserved for issuance under the 2009 Plan. Only unexercised options are outstanding under the 2009 Plan.

The Manager Committee may amend, modify, suspend, or terminate the 2009 Plan, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring unitholder approval under any applicable legal requirements will be effective until such approval has been obtained.

Performance Unit Awards. Beginning in 2015, our general partner and the managing member of ENLC granted performance awards under the GP Plan and the 2014 Plan, respectively. The performance award agreements provide that the vesting of restricted incentive units granted under the GP Plan and the 2014 Plan is dependent on the achievement of certain total shareholder return (“TSR”) performance goals relative to the TSR achievement of a peer group of companies (the “Peer Companies”) over the applicable performance period. The performance award agreements contemplate that the Peer Companies for an individual performance award (the “Subject Award”) are the companies comprising the Alerian MLP Index for Master Limited Partnerships (“AMZ”), excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of our and ENLC’s TSR achievement (“EnLink TSR”) for the applicable performance period relative to the TSR achievement of the Peer Companies. As of the effective time of the Merger, the performance metric for such performance awards was modified such that, the performance metric will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods after the effective time of the Merger.

At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units ranges from 0% to 200% of the units granted depending on the EnLink TSR or ENLC TSR as compared to the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated Peer Companies securities; (iii) an estimated ranking of us among the designated Peer Companies; and (iv) the distribution yield. In connection with the GIP Transaction, certain outstanding performance unit agreements were modified to increase the minimum vesting of units from zero to 100% as described in our Current Report on Form 8-K filed with the Securities and Exchange Commission on July 23, 2018. The fair value of the unit on the date of grant is expensed over a vesting period of approximately three years.

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in ENLK restricted incentive units and 50% in restricted incentive units of ENLC for fiscal year 2018. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions and change of ownership. For fiscal year 2018, our general partner granted 226,181, 133,798, 97,592, 98,605, 45,544, and 70,630 performance and restricted incentive units to Messrs. Garberding, Lamb, Davis, Batchelder, and Hummel, and Ms. Brooks, respectively. In addition, for fiscal year 2018, the managing member of ENLC granted 209,150, 125,979, 85,228, 90,763, 39,772 and 66,332 performance and restricted incentive units to Messrs. Garberding, Lamb, Davis, Batchelder, and Hummel and Ms. Brooks, respectively. All performance and restricted incentive units that we grant are charged against earnings according to ASC 718.

Anti-Hedging Policy. Pursuant to ENLK's insider trading policy, ENLK prohibits hedging of its securities by directors, officers, or employees and pledging of its securities as collateral by directors and executive officers.

Retirement and Health Benefits. All eligible employees are offered a variety of health and welfare and retirement programs. The named executive officers are generally eligible for the same programs on the same basis as other employees. We maintain a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2018, we matched 100% of every dollar contributed for contributions of up to 6% of eligible compensation made by eligible participants plus a 2% non-discretionary contribution plus a discretionary profit sharing contribution (not to exceed the maximum amount permitted by law). The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses.

Perquisites. We generally do not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax, and related expenses for membership in an industry-related private lunch club (totaling less than $2,500 per year per named executive officer).

Change in Control and Severance Agreements

All of our named executive officers and certain members of senior management have entered into amended change in control agreements (the "Change in Control Agreements") with the Operating Partnership and amended severance agreements (the "Severance Agreements" and collectively with the Change in Control Agreements, the "Agreements") with the Operating Partnership. Additionally, as certain individuals become members of senior management, the individual may become a party to a change in control agreement and/or a severance agreement in substantially the same form as the applicable Agreement.

The Agreements restrict the officers from competing with us, as well as the Operating Partnership, ENLC, its manager, our general partner, and their respective affiliates and subsidiaries (the "Company Group") during the term of employment. The Agreements also restrict the officers from disclosing confidential information of the Company Group and disparaging any member of the Company Group, in each case, during or after the term of their employment. In addition, the Agreements restrict the officers, both during their employment and for varying periods following the termination of employment, from (i) soliciting other employees to terminate their employment with any member of the Company Group or accept employment with a third party and (ii) diverting the business of a client or customer of any member of the Company Group or attempting to convert a client or customer of any member of the Company Group. The Agreements provide the Operating Partnership with equitable remedies and with the right to clawback benefits if the restrictions described in this paragraph are breached by the officer. In the event of a termination, the terminated employee is required to execute a general release of the Company Group in order to receive any benefits under the Agreements.

Under the Severance Agreements, if an officer's employment is terminated without cause (as defined in the Severance Agreement) or is terminated by the officer for good reason (as defined in the Severance Agreement), such officer will be entitled to receive (i) his or her accrued base salary up to the date of termination, (ii) any unpaid annual bonus with respect to the calendar year ending prior to the officer's termination date that has been earned as of such date, (iii) a prorated amount of the bonus (to the extent such bonus would have otherwise been earned by such officer) for the calendar year in which the termination occurs, (iv) such other fringe benefits (other than any bonus, severance pay benefit or medical insurance benefit) normally provided to employees that are already earned or accrued as of the date of termination (the foregoing items in clauses (i) - (iv) are referred to as the "General Benefits"), (v) certain outplacement services (the "Outplacement Benefits"), (vi) a lump sum severance equal to the sum of (A) the officer's then-current base salary and (B) any target bonus (as defined in the applicable Agreement) for the year that includes the date of termination (the "Severance Benefit") times two for the officer (other members of senior management are each entitled to one times the Severance Benefit), plus (vii) an amount equal to the cost to the officer to extend his or her then-current medical insurance benefits for 18 months following the effective date of the termination (the "Medical Severance Benefit").

Potential Payments Upon a Change of Control

Under the Change in Control Agreements, if, within a period that begins 120 days prior to and ends 24 months following a change in control (as defined in the Change in Control Agreement), an officer's employment is terminated without cause (as defined in the Change in Control Agreement) or is terminated by the officer for good reason (as defined in the Change in Control Agreement), such officer will be entitled to the General Benefits, the Outplacement Benefits, the Medical Severance Benefit and the Severance Benefit; provided, however, that the Chief Executive Officer ("CEO") and Executive Chairman would be entitled to three times the Severance Benefit, and the other officers would be entitled to two times the Severance Benefit. Other members of senior management do not receive an increase in the Severance Benefit if they are terminated in connection with a change in control.

In addition, the Agreements provide for the General Benefits upon the officer's termination of employment due to his or her death or disability (as defined in the Agreements).

The Agreements provide that an officer may only become entitled to payments under the Severance Agreement or the Change in Control Agreement, but not under both Agreements. Upon execution of a Severance Agreement, the Severance Agreement will continue in effect until (i) the first anniversary of the execution date; provided that the term will be automatically renewed for additional one-year periods beginning on the day following the first anniversary of the execution date (each, a "Renewal Date"), unless the Board provides the officer with written notice (a "Non-Renewal Notice") of the Operating Partnership's election not to renew the term at least 30 days prior to any Renewal Date or (ii) the termination of the officer's employment; provided that an officer's employment may not be terminated by the Operating Partnership for any reason other than cause (as defined in the Severance Agreement) for the 90-day period that follows the termination of the Severance Agreement pursuant to a Non-Renewal Notice. Upon execution of a Change in Control Agreement, the Change in Control Agreement will continue in effect until (i) the applicable Renewal Date and be automatically renewed for additional one-year periods unless the Board provides the officer with a Non-Renewal Notice at least 90 days prior to any Renewal Date or (ii) the termination of the officer's employment, except that a Change in Control Agreement may not be terminated for a period that begins 120 days prior to, and ends 24 months following, a change in control.

If the payments and benefits provided to an officer under the Agreements (i) constitute a "parachute payment" as defined in Section 280G of the IRC and exceed three times the officer's "base amount" as defined under Section 280G(b)(3) of the IRC, and (ii) would be subject to the excise tax imposed by Section 4999 of the IRC, then the officer's payments and benefits will be either (A) paid in full, or (B) reduced and payable only as to the maximum amount that would result in no portion of the payments and benefits being subject to such excise tax, whichever results in the receipt by the officer on an after-tax basis of the greatest amount (taking into account the applicable federal, state and local income taxes, the excise tax imposed by Section 4999 of the IRC and all other taxes, including any interest and penalties, payable by the officer).

With respect to the long-term incentive plans, the amounts to be received by our named executive officers in the event of a change of control (as defined in the long-term incentive plans) will be automatically determined based on the number of units underlying any unvested equity incentive awards held by a named executive officer at the time of a change of control. The terms of the long-term incentive plans were determined based on past practice and the applicable compensation committee's understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the applicable compensation committee.

Upon a change of control, and except as provided in the award agreement, the applicable compensation committee may cause options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control and except as provided in the award agreement, the applicable compensation committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement, or the other terms of such awards.

The potential payments that may be made to the named executive officers upon a termination of their employment or in connection with a change of control as of December 31, 2018 are set forth in the table in the section below entitled “Payments Upon Termination or Change in Control.”

Role of Executive Officers in Executive Compensation

Prior to the closing of the Merger and for the year ended December 31, 2018, the Board, upon recommendation of the Compensation Committee, determined the compensation payable to each of the named executive officers. None of the named executive officers served as a member of the Compensation Committee. The CEO made recommendations regarding the compensation of his leadership team with the Compensation Committee, including specific recommendations for each element of compensation for each of the named executive officers. The CEO did not make any recommendations regarding his personal compensation.

Tax Considerations

We have structured the compensation program in a manner intended to be exempt from, or to comply with, Section 409A of the IRC. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A of the IRC, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest, and an additional federal excise tax of 20% of the benefit includible in income.

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Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Restricted Incentive Unit, and Performance Unit Awards ($)(5)	All Other Compensation ($)	Total ($)
Michael J. Garberding	2018	646,600	1,009,247	7,975,169	727,195 (6)	10,358,211
President and Chief Executive Officer	2017	500,000	500,000	2,147,374	396,190	3,543,564
	2016	462,885	416,000	3,409,650	376,304	4,664,839
Benjamin D. Lamb (2)	2018	447,500	665,733	4,272,801	703,111 (7)	6,089,145
Executive Vice President and Chief Operating Officer	2017	345,000	345,000	1,431,552	274,563	2,396,115
	2016	318,558	250,000	2,181,257	212,310	2,962,125
Barry E. Davis	2018	529,000	784,367	3,835,864	784,034 (8)	5,933,265
Executive Chairman of the Board	2017	695,000	960,000	4,533,371	565,075	6,753,446
	2016	660,000	650,000	2,498,230	570,612	4,378,842
Eric D. Batchelder *Executive Vice President and Chief Financial Officer*	2018	399,200	560,771	3,133,675	304,836 (9)	4,398,482
Alaina K. Brooks (2)(3) *Executive Vice President, Chief Legal and Administrative Officer, and Secretary*	2018	393,300	468,087	2,410,163	204,661 (10)	3,476,211
McMillan Hummel (4)	2018	258,100	362,474	1,522,802	2,273,947 (11)	4,417,323
Executive Vice President / Business Unit President	2017	415,192	415,000	1,550,909	322,421	2,703,522
	2016	390,000	225,000	1,092,502	317,871	2,025,373

(1) Bonuses include all annual bonus payments. For 2016, the named executive officers received bonuses in the form of equity awards that immediately vest. Such equity awards were allocated 50% in restricted incentive units of ENLK and 50% in restricted incentive units of ENLC. For 2017, the named executive officers received bonuses in the form of 25% cash and 75% equity awards that immediately vest. Such equity awards were allocated 50% in restricted incentive units of ENLK and 50% in restricted incentive units of ENLC. For 2018, the named executive officers received bonuses in the form of 50% cash and 50% equity awards that immediately vest. Such equity awards were entirely allocated in restricted incentive units of ENLC. Equity awards for 2016, 2017, and 2018 represent the grant date fair value of awards computed in accordance with ASC 718.

(2) In June 2018, Mr. Lamb was promoted to Executive Vice President and Chief Operating Officer and Ms. Brooks was promoted to Executive Vice President, Chief Legal and Administrative Officer, and Secretary.

(3) Ms. Brooks became a named executive officer in fiscal year 2018, and, therefore, summary compensation information is presented only for fiscal year 2018.

(4) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

(5) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 10—Employee Incentive Plans" for the assumptions made in our valuation of such awards.

(6) Amount of all other compensation for Mr. Garberding includes a matching 401(k) contribution of $18,500, a 401(k) non-discretionary contribution of $5,500, a 401(k) discretionary profit-sharing contribution of $6,600, DERs with respect to restricted incentive units of ENLK in the amount of $429,040, and DERs with respect to restricted incentive units of ENLC in the amount of $267,555.

(7) Amount of all other compensation for Mr. Lamb includes a matching 401(k) contribution of $18,500, a 401(k) non-discretionary contribution of $5,500, a 401(k) discretionary profit-sharing contribution of $6,600, DERs with respect to restricted incentive units of ENLK in the amount of $414,345, and DERs with respect to restricted incentive units of ENLC in the amount of $258,166.

(8) Amount of all other compensation for Mr. Davis includes a matching 401(k) contribution of $24,500, a 401(k) non-discretionary contribution of $5,500, a 401(k) discretionary profit-sharing contribution of $6,600, DERs with respect to restricted incentive units of ENLK in the amount of $468,090, and DERs with respect to restricted incentive units of ENLC in the amount of $279,344.

(9) Amount of all other compensation for Mr. Batchelder includes a matching 401(k) contribution of $18,500, a 401(k) non-discretionary contribution of $5,500, a 401(k) discretionary profit-sharing contribution of $6,600, $140,644 toward moving expenses, DERs with respect to restricted incentive units of ENLK in the amount of $81,986, and DERs with respect to restricted incentive units of ENLC in the amount of $51,606.

(10) Amount of all other compensation for Ms. Brooks includes a matching 401(k) contribution of $18,500, a 401(k) non-discretionary contribution of $5,500, a 401(k) discretionary profit-sharing contribution of $6,600, DERs with respect to restricted incentive units of ENLK in the amount of $105,752, and DERs with respect to restricted incentive units of ENLC in the amount of $68,309.

(11) Amount of all other compensation for Mr. Hummel includes a matching 401(k) contribution of $22,551, $37,832 toward temporary housing expenses, DERs with respect to restricted incentive units of ENLK in the amount of $322,389, and DERs with respect to restricted incentive units of ENLC in the amount of $189,770. Mr. Hummel received $1,701,404 in connection with his departure.

CEO Pay Ratio

For fiscal year 2018, the annual total compensation for the President and Chief Executive Officer, Michael J. Garberding, was$10.4 million and for the median employee was $161,739. The resulting ratio of annual total compensation of the CEO to the annual total compensation of our median employee was 64:1. This pay ratio is a reasonable estimate calculated in accordance with the requirements of Item 402(u) of Regulation S-K. As a result of our methodology for determining the pay ratio, which is described below, our pay ratio may not be comparable to the pay ratios of other companies in our industry or in other industries because other companies may rely on different methodologies or assumptions or may make adjustments that we do not make. For 2018, the same median employee as 2017 was used to determine the pay ratio given that there has not been a material change to (i) the employee population, (ii) compensation arrangements believed to result in a significant change to the pay ratio, and (iii) the original median employee's circumstances (e.g., a promotion or demotion). If one of the aforementioned material changes did occur, the same approach used to identify the median employee in 2017 would have been applied for 2018.

To determine the pay ratio, we first identified the median employee by examining 2017 W-2 Box 1 Federal Taxable Wages (the "Taxable Wages Measure") for all of our employees, excluding the CEO, who were employed on December 31, 2017, the last business day of the 2017 fiscal year. We included all employees, whether employed as full-time, part-time, or on a seasonal basis, and compensation was annualized for any full-time employee that was not employed for all of fiscal year 2017. We use the Taxable Wages Measure because it is consistently applied for all employees and because we believe it reasonably reflects the annual compensation of our employees. After identifying the median employee, we calculated annual total compensation for the median employee using the same methodology used for calculating the annual total compensation of our named executive officers as set forth in the 2018 Summary Compensation Table above.

Narrative Disclosure to Summary Compensation Table

A narrative description of all material factors necessary to an understanding of the information included in the above Summary Compensation Table is included in the section titled "Compensation Discussion and Analysis" and in the footnotes to such tables.

Grants of Plan-Based Awards for Fiscal Year2018 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year2018, including, but not limited to, awards made under the GP Plan and the 2014 Plan.

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

		Estimated Future Payouts Under Equity Incentive Plan Awards					
Name	**Grant Date**	**Threshold (#) (1)**	**Target (#) (1)**	**Maximum (#)(1)**	**All Other Unit Awards: Number of Units**		**Grant Date Fair Value of Unit Awards ($)(4)**
Michael J. Garberding	3/13/2018	—	—	—	56,929	(2)	860,766
	3/13/2018	56,929	56,929	113,858	—		1,452,259
	8/1/2018	—	—	—	112,323	(3)	1,749,992
Benjamin D. Lamb	3/13/2018	—	—	—	22,772	(2)	344,313
	3/13/2018	22,772	22,772	45,544	—		438,133
	8/1/2018	—	—	—	32,092	(3)	499,993
	8/1/2018	—	—	—	56,162	(3)	875,004
Barry E. Davis	3/13/2018	—	—	—	48,796	(2)	737,796
	3/13/2018	48,796	48,796	97,592	—		1,244,786
Eric D. Batchelder	3/13/2018	—	—	—	20,332	(2)	307,420
	3/13/2018	20,332	20,332	40,664	—		391,188
	8/1/2018	—	—	—	13,012	(3)	196,741
	8/1/2018	—	—	—	44,929	(3)	699,994
Alaina K. Brooks	3/13/2018	—	—	—	12,850	(2)	194,292
	3/13/2018	12,850	12,850	25,700	—		327,804
	8/1/2018	—	—	—	22,465	(3)	350,005
	8/1/2018	—	—	—	22,465	(3)	350,005
McMillan Hummel (5)	3/13/2018	—	—	—	22,772	(2)	344,313
	3/13/2018	22,772	22,772	45,544	—		438,133

(1) These grants include accrued DERs that provide for distributions on performance awards, unless otherwise forfeited, if distributions are made on common units during the restriction period. When the performance awards vest on January 1, 2021, recipients receive DERs, if any, with respect to the number of performance awards vested.
(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2021.
(3) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 50% on August 1, 2020 and 50% on August 1, 2021.
(4) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 10—Employee Incentive Plans" for the assumptions made in our valuation of such awards.
(5) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

ENLINK MIDSTREAM, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#) (1)	Target (#) (1)	Maximum (#)(1)	All Other Unit Awards: Number of Units		Grant Date Fair Value of Unit Awards ($)(4)
Michael J. Garberding	3/13/2018	—	—	—	49,716	(2)	775,570
	3/13/2018	49,716	49,716	99,432	—		1,386,579
	8/1/2018	—	—	—	109,718	(3)	1,750,002
Benjamin D. Lamb	3/13/2018	—	—	—	19,886	(2)	310,222
	3/13/2018	19,886	19,886	39,772	—		430,134
	8/1/2018	—	—	—	31,348	(3)	500,001
	8/1/2018	—	—	—	54,859	(3)	875,001
Barry E. Davis	3/13/2018	—	—	—	42,614	(2)	664,778
	3/13/2018	42,614	42,614	85,228	—		1,188,504
Eric D. Batchelder	3/13/2018	—	—	—	17,756	(2)	276,994
	3/13/2018	17,756	17,756	35,512	—		384,062
	8/1/2018	—	—	—	11,364	(3)	177,278
	8/1/2018	—	—	—	43,887	(3)	699,998
Alaina K. Brooks	3/13/2018	—	—	—	11,222	(2)	175,063
	3/13/2018	11,222	11,222	22,444	—		312,982
	8/1/2018	—	—	—	21,944	(3)	350,007
	8/1/2018	—	—	—	21,944	(3)	350,007
McMillan Hummel (5)	3/13/2018	—	—	—	19,886	(2)	310,222
	3/13/2018	19,886	19,886	39,772	—		430,134

(1) These grants include accrued DERs that provide for distributions on performance awards, unless otherwise forfeited, if distributions are made on common units during the restriction period. When the performance awards vest on January 1, 2021, recipients receive DERs, if any, with respect to the number of performance awards vested.
(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2021.
(3) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 50% on August 1, 2020 and 50% on August 1, 2021.
(4) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See “Item 8. Financial Statements and Supplementary Data—Note 10—Employee Incentive Plans” for the assumptions made in our valuation of such awards.
(5) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year2018

The following tables provide information concerning all outstanding equity awards made to a named executive officer as ofDecember 31, 2018, including, but not limited to, awards made under the GP Plan, 2014 Plan and 2009 Plan.

ENLINK MIDSTREAM GP, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

		Stock Awards			
Name	Vesting Year (1)	Number of Units That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)
Michael J. Garberding	2021	113,091	1,245,132	56,929	626,788
	2020	101,572	1,118,308	45,411	499,975
	2019	82,712	910,659	33,784	371,962
Benjamin D. Lamb (4)	2021	66,899	736,558	—	—
	2020	74,400	819,144	—	—
	2019	53,588	590,004	—	—
Barry E. Davis	2021	48,796	537,244	48,796	537,244
	2020	51,241	564,163	51,241	564,163
	2019	128,145	1,410,876	58,248	641,310
Eric D. Batchelder (4)	2021	55,809	614,457	—	—
	2020	22,464	247,329	—	—
Alaina K. Brooks	2021	35,316	388,829	12,850	141,479
	2020	31,903	351,252	9,439	103,923
	2019	13,429	147,853	13,429	147,853
McMillan Hummel (4)(5)	—	—	—	—	—

(1) Restricted incentive units vesting in 2019 vest on January 1, 2019. Restricted incentive units vesting in 2020 and 2021 vest on January 1st and August 1st of the relevant year, as applicable.

(2) The closing price for the ENLK common units was $11.01 as of December 31, 2018.

(3) Reflects the target number of performance units granted to the named executive officers multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2019 is contingent upon the EnLink TSR performance. For performance periods ending after January 1, 2019, vesting of these awards in the relevant year is contingent upon (i) the EnLink TSR performance measured against a peer group of companies in respect of periods preceding the effective time of the Merger and (ii) the TSR performance of ENLC measured against a peer group of companies in respect of periods after the effective time of the Merger.

(4) In connection with the GIP Transaction, outstanding performance units held by certain executives who elected not to waive their rights to have such awards vest due to the closing of the GIP Transaction vested at 100%.

(5) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President. Pursuant to his departure, Mr. Hummel's outstanding restricted incentive units vested and his outstanding performance units vested at 100% in 2018.

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ENLINK MIDSTREAM, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

		Unit Awards			
Name	**Vesting Year (1)**	**Number of Units That Have Not Vested (#)**	**Market Value of Shares or Units That Have Not Vested ($)(2)**	**Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)(2)**
Michael J. Garberding	2021	104,575	992,417	49,716	471,805
	2020	100,910	957,636	46,051	437,024
	2019	71,457	678,127	29,187	276,985
Benjamin D. Lamb (4)	2021	62,990	597,775	—	—
	2020	73,803	700,390	—	—
	2019	46,296	439,349	—	—
Barry E. Davis	2021	42,614	404,407	42,614	404,407
	2020	47,739	453,043	47,739	453,043
	2019	110,709	1,050,628	50,322	477,556
Eric D. Batchelder (4)	2021	51,064	484,597	—	—
	2020	21,943	208,239	—	—
Alaina K. Brooks	2021	33,166	314,745	11,222	106,497
	2020	30,738	291,704	8,794	83,455
	2019	14,286	135,574	14,286	135,574
McMillan Hummel (4)(5)	—	—	—	—	—

(1) Restricted incentive units vesting in 2019 vest on January 1, 2019. Restricted incentive units vesting in 2020 and 2021 vest on January 1st and August 1st of the relevant year, as applicable.

(2) The closing price for the ENLC common units was $9.49 as of December 31, 2018.

(3) Reflects the target number of performance units granted to the named executive officers multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2019 is contingent upon the EnLink TSR performance. For performance periods ending after January 1, 2019, vesting of these awards in the relevant year is contingent upon (i) the EnLink TSR performance measured against a peer group of companies in respect of periods preceding the effective time of the Merger and (ii) the TSR performance of ENLC measured against a peer group of companies in respect of periods after the effective time of the Merger.

(4) In connection with the GIP Transaction, outstanding performance units held by certain executives who elected not to waive their rights to have such awards vest due to the closing of the GIP Transaction vested at 100%.

(5) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President. Pursuant to his departure, Mr. Hummel's outstanding restricted incentive units vested and his outstanding performance units vested at 100% in 2018.

Units Vested Table for Fiscal Year 2018

The following tables provide information related to the vesting of restricted units and restrictive incentive units during fiscal year ended2018.

ENLINK MIDSTREAM GP, LLC—UNITS VESTED

Name	Date Vested	Number of Units Acquired on Vesting		Value Per Unit Realized on Vesting ($)	Total ($)
Michael J. Garberding	1/1/18	17,532		15.37	269,467
	1/22/18	17,532		17.45	305,933
	3/5/18	12,669		14.80	187,501
Benjamin D. Lamb	1/1/18	11,695		15.37	179,752
	1/22/18	11,695		17.45	204,078
	3/5/18	8,742		14.80	129,382
	4/1/18	4,858		13.66	66,360
	7/18/18	69,354	(1)	14.93	1,035,455
Barry E. Davis	1/1/18	30,680		15.37	471,552
	1/22/18	30,680		17.45	535,366
	3/5/18	24,324		14.80	359,995
Eric D. Batchelder	7/18/18	20,332	(1)	14.93	303,557
Alaina K. Brooks	1/1/18	4,678		15.37	71,901
	1/22/18	4,678		17.45	81,631
	3/5/18	5,533		14.80	81,888
McMillan Hummel (2)	1/1/18	14,025		15.37	215,564
	1/22/18	14,025		17.45	244,736
	3/5/18	10,515		14.80	155,622
	7/18/18	65,931	(1)	14.93	984,350
	8/2/18	96,220		16.72	1,608,798

(1) In connection with the GIP Transaction, outstanding performance units held by certain executives who elected not to waive their rights to have such awards vest due to the closing of the GIP Transaction vested at 100%.

(2) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President. Pursuant to his departure, Mr. Hummel's outstanding restricted incentive units vested and his outstanding performance units vested at 100% in 2018.

ENLINK MIDSTREAM, LLC—UNITS VESTED

Name	Date Vested	Number of Units Acquired on Vesting	Value Per Unit Realized on Vesting ($)	Total ($)
Michael J. Garberding	1/1/18	15,823	17.60	278,485
	1/22/18	15,823	18.75	296,681
	3/5/18	12,255	15.30	187,502
Benjamin D. Lamb	1/1/18	10,074	17.60	177,302
	1/22/18	10,074	18.75	188,888
	3/5/18	8,456	15.30	129,377
	4/1/18	3,556	14.65	52,095
	7/18/18	64,676 (1)	15.30	989,543
Barry E. Davis	1/1/18	27,690	17.60	487,344
	1/22/18	27,690	18.75	519,188
	3/5/18	23,529	15.30	359,994
Eric D. Batchelder	7/18/18	17,756 (1)	15.30	271,667
Alaina K. Brooks	1/1/18	4,030	17.60	70,928
	1/22/18	4,030	18.75	75,563
	3/5/18	5,352	15.30	81,886
McMillan Hummel (2)	1/1/18	12,658	17.60	222,781
	1/22/18	12,658	18.75	237,338
	3/5/18	10,172	15.30	155,632
	7/18/18	58,360 (1)	15.30	892,908
	8/2/18	84,527	17.35	1,466,543

(1) In connection with the GIP Transaction, outstanding performance units held by certain executives who elected not to waive their rights to have such awards vest due to the closing of the GIP Transaction vested at 100%.

(2) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President. Pursuant to his departure, Mr. Hummel's outstanding restricted incentive units vested and his outstanding performance units vested at 100% in 2018.

Payments Upon Termination or Change of Control

The following tables show potential payments that would have been made to the named executive officers as ofDecember 31, 2018.

Named Executive Officer	Payment Under Severance Agreements Upon Termination Other Than For Cause or With Good Reason ($)(1)	Health Care Benefits Under Change in Control and Severance Agreements Upon Termination Other Than For Cause or With Good Reason ($)(2)	Payment and Health Care Benefits Under Change in Control and Severance Agreements Upon Termination For Cause or Without Good Reason ($)(3)	Payment Under Change in Control Agreements Upon Termination and Change of Control ($)(4)	Acceleration of Vesting Under Long-Term Incentive Plans Upon Change of Control ($)(5)
Michael J. Garberding	3,659,247	30,853	—	4,959,247	8,586,817
Benjamin D. Lamb	2,615,733	33,140	—	2,615,733	3,883,220
Barry E. Davis	2,881,867	33,678	—	3,905,617	7,498,086
Eric D. Batchelder	2,263,771	20,901	—	2,263,771	1,554,622
Alaina K. Brooks	2,133,087	30,853	—	2,133,087	2,348,739
McMillan Hummel (6)	—	—	—	—	—

(1) Each named executive officer is entitled to a lump sum amount equal to two times the Severance Benefit, the Outplacement Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if he or she is terminated without cause (as defined in the Severance Agreement) or if he or she terminates employment for good reason (as defined in the Severance Agreement), subject to compliance with certain non-competition and non-solicitation covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(2) Each named executive officer is entitled to health care benefits equal to a lump sum payment of the estimated monthly cost of the benefits under COBRA for 18 months if he or she is terminated without cause (as defined in the applicable Severance Agreement or Change of Control Agreement (the "Applicable Agreement") or if he or she terminates employment for good reason (as defined in the Applicable Agreement)).

(3) Each named executive officer is entitled to his or her then current base salary up to the date of termination plus such other fringe benefits (other than any bonus, severance pay benefit, participation in the company's 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company as earned up to the date of termination if he or she is terminated for cause (as defined in the Applicable Agreement) or he or she terminates employment without good reason (as defined in the Applicable Agreement). The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(4) Each named executive officer is entitled to a lump sum payment equal to two times the Severance Benefit (three times in the case of the Chief Executive Officer and Executive Chairman), the Outplacement Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if he or she is terminated without cause (as defined in the Change of Control Agreement) or if he or she terminates employment for good reason (as defined in the Change of Control Agreement) within 120 days prior to or two years following a change in control (as defined in the Severance Agreement), subject to compliance with certain non-competition, non-solicitation, and other covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(5) Each named executive officer is entitled to accelerated vesting of certain outstanding equity awards in the event of a change of control (as defined under the long-term incentive plans). These amounts correspond to the values set forth in the table in the section above entitled Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2018.

(6) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President. Pursuant to his departure, Mr. Hummel received a cash payment of $1,701,404 related to his Severance Benefit, $362,474 related to his 2018 bonus, and accelerated vesting of outstanding equity awards valued at $3,075,342 as of the vesting date.

Compensation of Directors for Fiscal Year 2018

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($) (1)	All Other Compensation ($)(2)	Total ($)
Leldon E. Echols (3)	48,250	55,629	5,383	109,262
Scott A. Griffiths (3)	217,667	111,257	10,766	339,690
Kyle D. Vann (3)	245,472	111,257	10,766	367,495
Mary P. Ricciardello (4)	35,951	55,629	2,465	94,045

(1) Messrs. Echols, Griffiths, and Vann, and Ms. Ricciardello were granted awards of restricted incentive units of ENLK on March 7, 2018 with a fair market value of $14.87 per unit and that will vest on March 7, 2019 in the following amounts, respectively: 3,741, 7,482, 7,482, and 3,741. Mr. Echols and Ms. Ricciardello were granted awards of restricted incentive units of ENLC on March 7, 2018 with a fair market value of $15.30 per unit and that will vest on March 7, 2019 in the following amounts, respectively: 3,267 and 3,267. The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 10—Employee Incentive Plans" for the assumptions made in our valuation of such awards. At December 31, 2018, Messrs. Echols, Griffiths, and Mr. Vann and Ms. Ricciardello held aggregate outstanding restricted incentive unit awards of ENLK, in the following amounts, respectively: 3,741, 7,482, 7,482, and 3,741. At December 31, 2018, Mr. Echols and Ms. Ricciardello held aggregate outstanding restricted incentive units of ENLC in the following amounts, respectively: 3,267 and 3,267.

(2) Other Compensation is comprised of DERs with respect to restricted incentive units.

(3) In connection with the closing of the Merger, each of Messrs. Echols, Griffiths, and Vann departed from their positions as directors.

(4) In July 2018, Ms. Ricciardello departed from her position as a director. Pursuant to her departure, Ms. Ricciardello's outstanding restricted incentive units vested in 2018.

For the fiscal year 2018, each director of EnLink Midstream GP, LLC who was not an employee of EnLink Midstream GP, LLC or GIP (or Devon, as applicable) was paid an annual retainer fee of $72,500 and equity compensation valued at $115,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting or each additional meeting that they attend. In 2018, the respective chairs of each committee received the following annual fees for fiscal year ended 2018: Audit—$12,000, Compensation Committee and the Manager Committee—$15,000 and Conflicts—$20,000. The respective members of each committee received the following annual fees for the fiscal year ended 2018: Audit—$17,500, Compensation Committee and the Manager Committee—$7,500 and Conflicts—$15,000. Directors were also reimbursed for related out-of-pocket expenses. For directors that served on both the boards of EnLink Midstream GP, LLC and EnLink Midstream Manager, LLC, the above listed fees were allocated 50% to us and 50% to ENLC.

Michael J. Garberding, Barry E. Davis, and Alaina K. Brooks as officers of the Managing Member, receive no separate compensation for their respective service as directors.

Compensation Committee Interlocks and Insider Participation

As of December 31, 2018, the Compensation Committee was composed of Scott A. Griffiths and William J. Brilliant. No member of the Compensation Committee during fiscal 2018 was a current or former officer or employee of EnLink Midstream GP, LLC or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the SEC. None of EnLink Midstream GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity for which any officers of such other entity served either on the Board or the Compensation Committee.

Board Leadership Structure and Risk Oversight

The Board has no policy that requires that the positions of the Chairman of the Board (the "Chairman") and the Chief Executive Officer be separate or that they be held by the same individual. The Board believes that this determination should be based on circumstances existing from time to time, including the composition, skills, and experience of the Board and its members, specific challenges faced by us or the industry in which we operate, and governance efficiency. Based on these factors, the Board determined that having Barry E. Davis serve as the Chief Executive Officer and Chairman up to January 2018 was in our best interest, and that such arrangement made the best use of Mr. Davis' unique skills and experience in the industry. In January 2018, the Board appointed Mr. Davis to Executive Chairman and Mr. Garberding to President and Chief Executive Officer, thereby separating the positions of Chairman and Chief Executive Officer.

The Board is responsible for risk oversight. Management has implemented internal processes to identify and evaluate the risks inherent in our business and to assess the mitigation of those risks. The Audit Committee of ENLC (the “Manager Audit Committee”) will review the risk assessments with management and provide reports to the Board regarding the internal risk assessment processes, the risks identified, and the mitigation strategies planned or in place to address the risks in the business. The Board and the Manager Audit Committee each provide insight into the issues, based on the experience of their members, and provide constructive challenges to management’s assumptions and assertions.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

EnLink Midstream Partners, LP Ownership

The following table shows the beneficial ownership of units of ENLK as ofFebruary 13, 2019, held by:

- each person who is known to ENLK to beneficially own more than 5% of any class of voting units then outstanding;
- all the directors of EnLink Midstream GP, LLC;
- each named executive officer of EnLink Midstream GP, LLC; and
- all the directors and executive officers of EnLink Midstream GP, LLC as a group.

On January 25, 2019, ENLK completed the Merger, pursuant to which each issued and outstanding ENLK common unit (except for ENLK common units held by ENLC and its subsidiaries) have been converted into the right to receive 1.15 ENLC common units.

The percentage of total units beneficially owned is based upon a total of144,535,672 common units as of February 13, 2019. Prior to the closing of the Merger, the Series B Preferred Units were convertible into common units of ENLK. Following the closing of Merger, the Series B Preferred Units are no longer convertible into common units of ENLK and are exchangeable on a 1-for-1.15 basis (subject to certain adjustments) for common units of ENLC. Therefore, the Series B Preferred Units are not factored into the percentage ownership calculations. Series C Preferred Units are perpetual preferred units that are not convertible into common units and therefore are not factored into the percentage ownership calculations. None of the named beneficial owners set forth in the table below owns any of the 59,154,779 Series B Preferred Units or the 400,000 outstanding Series C Preferred Units as of February 13, 2019.

Name of Beneficial Owner (1)	Common Units Beneficially Owned (2)	Percentage of Common Units Beneficially Owned
Global Infrastructure Investors III, LLC (3) (4)	144,535,672	100.00 %
Barry E. Davis	—	— %
Michael J. Garberding	—	— %
Eric D. Batchelder	—	— %
Benjamin D. Lamb	—	— %
Alaina K. Brooks	—	— %
McMillan Hummel (5)	—	— %
All directors and executive officers as a group (5 persons)	—	— %

(1) The address of each person listed above is 1722 Routh Street, Suite 1300, Dallas, Texas 75201, except for Global Infrastructure Investors III, LLC, whose address is 1345 Avenue of the Americas, 30th Floor, New York, New York 10105.

(2) Pursuant to Rule 13d-3 under the Exchange Act, a person has beneficial ownership of a security as to which that person, directly or indirectly, through any contract, arrangement, understanding, relationship, or otherwise has or shares voting power and/or investment power of such security and as to which that person has the right to acquire beneficial ownership of such security within 60 days.

(3) ENLC is the record holder of 144,535,672 common units of ENLK. Global Infrastructure Investors III, LLC ("Global Investors") is the sole general partner of Global Infrastructure GP III, L.P. (“Global GP”), which is the general partner of each of GIP III Stetson Aggregator I, L.P. (“Aggregator I”) and GIP III Stetson Aggregator II, L.P. (“Aggregator II”), which are the managing members of GIP III Stetson GP, LLC (“Stetson GP”), which is the general partner of GIP III Stetson I, L.P. (“Stetson I”), which is the sole member of EnLink Midstream Manager, LLC, which is the managing member of ENLC. As a result, Global Investors, Global GP, Aggregator I, Aggregator II, Stetson GP, Stetson I, and EnLink Midstream Manager, LLC may be deemed to share beneficial ownership of the Common Units held by ENLC.

(4) As the indirect owner of 40.4% of the outstanding membership interest in EnLink Midstream, LLC, and 100% of the outstanding membership interest in EnLink Midstream, LLC’s managing member, GIP may be deemed to beneficially own all common units.

(5) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

EnLink Midstream, LLC Ownership

The following table shows the beneficial ownership of the units of ENLC as ofFebruary 13, 2019, held by:

- all the directors of EnLink Midstream GP, LLC;
- each named executive officer of EnLink Midstream GP, LLC; and
- all the directors and executive officers of EnLink Midstream GP, LLC as a group.

The percentage of total common units of ENLC beneficially owned is based on a total of486,879,590 units (including 244,664 restricted incentive units that are deemed beneficially owned) as of February 13, 2019.

Name of Beneficial Owner (1)	Common Units Beneficially Owned (2)	Percentage of Common Units Beneficially Owned (3)	ENLC Class C Common Units Beneficially Owned (2)	Percentage of ENLC Class C Common Units Beneficially Owned	Total Units Beneficially Owned (2)	Percentage of Total Units Beneficially Owned (4)
Barry E. Davis (5)	2,679,249	*	—	—	2,679,249	*
Michael J. Garberding (6)	544,116	*	—	—	544,116	*
Eric D. Batchelder	24,950	*	—	—	24,950	*
Benjamin D. Lamb	242,288	*	—	—	242,288	*
Alaina K. Brooks (7)	48,626	*	—	—	48,626	*
McMillan (Mac) Hummel (8)	318,635	*	—	—	318,635	*
All directors and executive officers as group (5 persons)	3,539,229	*	—	—	3,539,229	*

* Less than 1%

(1) The address of each person listed above is 1722 Routh Street, Suite 1300, Dallas, Texas 75201.

(2) Pursuant to Rule 13d-3 under the Exchange Act, a person has beneficial ownership of a security as to which that person, directly or indirectly, through any contract, arrangement, understanding, relationship, or otherwise has or shares voting power and/or investment power of such security and as to which that person has the right to acquire beneficial ownership of such security within 60 days.

(3) The percentages reflected in the column below are based on a total of 486,879,590 common units (including 244,664 restricted incentive units that are deemed beneficially owned).

(4) The percentages reflected in the column below are based on a total of 554,907,586 common units, which includes the units described in (3) above, and 68,027,996 common units, which reflects the as-exchanged amount of the 59,154,779 ENLC Class C Common Units held by Enfield, which owns the same number of Series B Preferred Units. The Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments. For this reason, the percentages in this column reflect the exchange of the Series B Preferred Units into ENLC common units. Upon any exchange of Series B Preferred Units into ENLC common units, an equal number of ENLC Class C Common Units will be cancelled.

(5) Includes 2,555,842 ENLC common units owned of record by Mr. Davis and 123,407 restricted incentive units that are deemed beneficially owned. Of these common units of the Company owned, 964,724 are held by MK Holdings, LP, a family limited partnership, which Mr. Davis controls, and Mr. Davis disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.

(6) Includes 472,540 common units owned of record by Mr. Garberding and 71,576 restricted incentive units that are deemed beneficially owned.

(7) Includes 17,351 common units owned of record by Ms. Brooks and 31,275 restricted incentive units that are deemed beneficially owned.

(8) In August 2018, Mr. Hummel departed from his position as Executive Vice President / Business Unit President.

Beneficial Ownership of General Partner Interest

EnLink Midstream GP, LLC owns all of our general partner interest. Prior to the closing of the Merger, our distributions were made to our general partner based on its ownership interest with the remaining interest to unitholders, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders were achieved. Subsequent to the closing of the Merger, no incentive distributions are paid to our general partner. EnLink Midstream GP, LLC is wholly-owned by ENLC.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights		Weighted-Average Price of Outstanding Options, Warrants and Rights		Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a))
	(a)		(b)		(c)
Equity Compensation Plans Approved by Security Holders (1)	3,064,822	(2)	$ 4.65	(3)	3,418,034
Equity Compensation Plans Not Approved by Security Holders	N/A		N/A		N/A

(1) The GP Plan was approved by our unitholders, effective April 6, 2016, for the benefit of our officers, employees and directors. See "Item 11. Executive Compensation—Compensation Discussion and Analysis." The plan, as amended, provides for the issuance of a total of 14,070,000 common units under the plan.
(2) The number of securities includes 2,556,270 restricted incentive units that have been granted under the GP Plan that have not vested. In addition, the number of securities includes 451,669 performance unit awards granted under the plan, assuming the target distribution at the time of vesting. Actual issuance of these performance unit awards may range from 0% to 200% of the target distribution depending on performance actually attained.
(3) The exercise prices for outstanding options under the plan as of December 31, 2018 range from $3.11 to $6.00 per unit.

Effective as of the closing of the Merger, all unit-based awards issued and outstanding immediately prior to the effective time of the Merger under the GP Plan have been converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting of terms of applicable awards related to the performance of ENLC.

Item 13. Certain Relationships and Related Transactions and Director Independence

Our General Partner

Our operations and activities are managed by, and our officers are employed by, the Operating Partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf. Our general partner owns the general partner interest in us.

Relationship with GIP and EnLink Midstream, LLC

As a result of the Merger, ENLC owns all of our outstanding common units. ENLC also owns our general partner and has the power to appoint all of the officers and directors of our general partner. ENLC is managed by its managing member, which is wholly-owned by GIP. Therefore, GIP indirectly controls our general partner, which has the sole authority to manage and operate our business. Accordingly, through its control of our general partner, GIP effectively has the ability to control our management. Refer to "Item 8. Financial Statements and Supplementary Information—Note 5—Related Party Transactions for additional information.

In connection with the Merger, ENLC issued 304,822,035 common units to acquire all of our outstanding common units not previously owned by ENLC. As of the closing date of the Merger, the price of an ENLC common unit was $10.53 per unit.

Related Party Transactions

Refer to "Item 8. Financial Statements and Supplementary Information—Note 5—Related Party Transactions" for information about our related party transactions, including commercial agreements with Devon.

Office Leases

In March 2014, we entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which we lease office space at Devon's Bridgeport, Oklahoma City, and Cresson office buildings. We had rent payable to Devon under these lease agreements of $102,000, $18,000, and $33,000, respectively, for the period of January 1, 2018 to July 18, 2018.

Certain Relationships

From time to time, we may do business with other companies affiliated with TPG, which holds an interest in Enfield, the beneficial owner of our Series B Preferred Units, or with Natural Resources XI, L.P., Marathon Petroleum Corporation, or Kinder Morgan, Inc., our joint venture partners in the Delaware Basin JV, Ascension JV, and Cedar Cove JV, respectively. We believe that any such arrangements have been or will be conducted on an arms-length basis.

Indemnification of Directors and Officers

We have entered into indemnification agreements (the "Indemnification Agreements") with each of the general partner's directors and executive officers (collectively, the "Indemnitees"). Under the terms of the Indemnification Agreements, we agree to indemnify and hold each Indemnitee harmless, subject to certain conditions, from and against any and all losses, claims, damages, liabilities, judgments, fines, taxes (including ERISA excise taxes), penalties (whether civil, criminal, or other), interest, assessments, amounts paid or payable in settlements, or other amounts (collectively, "losses") and expenses (as defined in the Indemnification Agreements) arising from any and all threatened, pending, or completed claims, demands, actions, suits, proceedings, or alternative dispute mechanisms, whether civil, criminal, administrative, arbitrative, investigative, or other, whether made pursuant to federal, state, or local law, whether formal or informal, and including appeals (a "proceeding"), in which the Indemnitee may be involved, or is threatened to be involved, as a party, a witness, or otherwise, including any inquiries, hearings, or investigations that the Indemnitee determines might lead to the institution of any proceeding, related to the fact that Indemnitee is or was a director, manager, or officer of us, the general partner, or the managing member of ENLC or is or was serving at the request of us, the general partner, or the managing member of ENLC as a manager, managing member, general partner, director, officer, fiduciary, trustee, or agent of any other entity, organization, or person of any nature, including service with respect to employee benefit plans, or by reason of an action or inaction by Indemnitee in any such capacity on behalf of, for the benefit of, or at the request of us, the general partner, or the managing member of ENLC. We have also agreed to advance the expenses of an Indemnitee relating to the foregoing. To the extent that a change in the laws of the State of Delaware permits greater indemnification under any statute, agreement, organizational document, or governing document than would be afforded under the Indemnification Agreements as of the date of the Indemnification Agreements, the Indemnitee shall enjoy the greater benefits so afforded by such change.

Approval and Review of Related Party Transactions

Our policies and procedures for the review, approval, or ratification of transactions with "related persons" are contained in our Code of Business Conduct and Ethics (the "Code of Ethics") as well as our partnership agreement. Pursuant to our Code of Ethics, the Audit Committee of the Manager Board must approve any transaction, arrangement, or relationship, or any series of similar transactions, arrangements, or relationships, in which ENLK or any of its subsidiaries is or will be a participant, the aggregate amount involved will or may be expected to exceed $120,000 in any fiscal year, and any director, executive officer, equity holder owning more than 5% of any class of ENLK's securities, or any immediate family member of any of the foregoing has or will have a direct or indirect interest.

Whenever a conflict arises between the general partner of ENLK or its affiliates, on the one hand, and ENLK and certain of its affiliates, on the other hand, the general partner of ENLK will resolve that conflict in accordance with the provisions of our partnership agreement. The general partner is authorized but not required in connection with its resolution of such conflict of interest to seek approval of a majority of the members of the Conflicts Committee of the Board, if such a committee has been formed. Any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to ENLK if such conflict of interest or resolution is (i) approved by a majority of the members of the Conflicts Committee (as long as the material facts known to the general partner or any of its affiliates regarding any proposed transaction were disclosed to the Conflicts Committee at the time it gave its approval), (ii) on terms no less favorable to ENLK than those generally being provided to or available from unrelated third parties, or (iii) fair to ENLK, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to ENLK).

Director Independence

Following the Merger, we do not have securities listed on the NYSE or any other national securities exchange and are no longer subject to the rules of the NYSE, including rules that require independent directors on the Board. As a result, as of immediately following the Merger, we do not have any independent directors on the Board. See "Item 10. Directors, Executive Officers, and Corporate Governance" for information regarding director independence.

Item 14. Principal Accounting Fees and Services

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for the fiscal years ended December 31, 2018, 2017, and 2016, review of our internal control procedures for the fiscal years ended December 31, 2018, 2017, and 2016, and the reviews of the financial statements included in our quarterly reports on Form 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagements for each of those fiscal years were $1.8 million, $1.7 million, and $1.9 million, respectively. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services in connection with the audit or review of our financial statements for the fiscal years ended December 31, 2018, 2017, and 2016 that were not included in the audit fees listed above.

Tax Fees

KPMG did not perform any tax related services for the years ended December 31, 2018, 2017, and 2016, except for certain tax related services in the amount of $17.5 thousand for the year ended December 31, 2018 for the preparation of calculations under Internal Revenue Code Section 280G, Golden Parachute Payments, in connection with Mr. Hummel's departure from his position as Executive Vice President / Business Unit President in August 2018.

All Other Fees

KPMG did not render services to us, other than those services covered in the section captioned "Audit Fees" for the fiscal years ended December 31, 2018, 2017, and 2016.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in our annual engagement letter for audit services must be pre-approved by the applicable audit committee. The Chairman of the Manager Audit Committee is authorized by the Manager Audit Committee to pre-approve additional KPMG audit and non-audit services between meetings of the Manager Audit Committee, provided that the additional services do not affect KPMG's independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Manager Audit Committee at its next meeting. For the year ended December 31, 2018, the Audit Committee of the Board pre-approved KPMG providing certain tax related services in the amount of $17.5 thousand for the preparation of calculations under Internal Revenue Code Section 280G, Golden Parachute Payments, in connection with Mr. Hummel's departure from his position as Executive Vice President / Business Unit President in August 2018.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

1. See "Item 8. Financial Statements and Supplementary Data."

2. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number			Description
2.1	**	—	TOM-STACK Securities Purchase Agreement, dated as of December 6, 2015, among Tall Oak Midstream, LLC, FE-STACK, LLC, TOM-STACK Holdings, LLC, TOM-STACK, LLC, EnLink TOM Holdings, LP and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 6, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
2.2	**	—	TOMPC Securities Purchase Agreement, dated as of December 6, 2015, among TOMPC LLC, Tall Oak Midstream, LLC, EnLink TOM Holdings, LP, and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K dated December 6, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
2.3	**	—	Agreement and Plan of Merger, dated as of October 21, 2018, by and among EnLink Midstream, LLC, EnLink Midstream Manager, LLC, NOLA Merger Sub, LLC, EnLink Midstream Partners, LP, and EnLink Midstream GP, LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
3.1		—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2		—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.3		—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.4		—	Third Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 16, 2017, filed with the Commission on June 19, 2017, file No. 001-36340).
3.5		—	Tenth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
3.6		—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.7		—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to our Registration Statement on Form S-3, file No. 333-194465).
3.8		—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36340).
4.1		—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 12 to our Registration Statement on Form 8-A, filed with the Commission on March 7, 2014, file No. 001-36340).
4.2		—	Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.3		—	First Supplemental Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).

4.4		—	Second Supplemental Indenture, dated as of November 12, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated November 6, 2014, filed with the Commission on November 12, 2014, file No. 001-36340).
4.5		—	Third Supplemental Indenture, dated as of May 12, 2015, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated May 7, 2015, filed with the Commission on May 12, 2015).
4.6		—	Fourth Supplemental Indenture, dated as of July 14, 2016, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated July 11, 2016, filed with the Commission on July 14, 2016, file No. 001-36340).
4.7		—	Fifth Supplemental Indenture, dated as of May 11, 2017, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated May 11, 2017, filed with the Commission on May 11, 2017, file No. 001-36340).
10.1		—	Preferential Rights Agreement, dated as of March 7, 2014, by and among Crosstex Energy, Inc., EnLink Midstream Partners, LP and EnLink Midstream, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.2		—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36340).
10.3	†	—	EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated January 25, 2019 (the “GP Plan”) (incorporated by reference to Exhibit 4.2 to EnLink Midstream, LLC’s Registration Statement on Form S-8 dated January 28, 2019, filed with the Commission on January 28, 2019, file No. 333-229393).
10.4	†	—	EnLink Midstream, LLC 2014 Long-Term Incentive Plan, as amended and restated January 25, 2019 (the “2014 Plan”) (incorporated by reference to Exhibit 4.1 to EnLink Midstream, LLC’s Registration Statement on Form S-8 dated January 28, 2019, filed with the Commission on January 28, 2019, file No. 333-229393).
10.5	†*	—	Form of Amended Performance Conditions for Certain Performance Unit Agreements made under the GP Plan and 2014 Plan, effective as of January 25, 2019.
10.6	†	—	Form of Amended and Restated Severance Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 31, 2014, filed with the Commission on November 3, 2014, file No. 001-36340).
10.7		—	Form of Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 12, 2015, filed with the Commission June 15, 2015, file No. 001-36340).
10.8		—	Revolving Credit Agreement, dated as of December 11, 2018, by and among EnLink Midstream, LLC, Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to EnLink Midstream, LLC’s Current Report on Form 8-K dated December 11, 2018, filed with the Commission on December 12, 2018, file No. 001-36336).
10.9		—	Term Loan Agreement, dated as of December 11, 2018, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 11, 2018, filed with the Commission on December 12, 2018, file No. 001-36340).
10.10		—	Guaranty Agreement, dated as of January 25, 2019, by EnLink Midstream Partners, LP in favor of Bank of America, N.A., as Administrative Agent, for the ratable benefit of the lenders from time to time party to the Revolving Credit Agreement, dated as of December 11, 2018 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
10.11		—	New Borrower Joinder and Assumption Agreement, dated January 25, 2019, by EnLink Midstream, LLC and EnLink Midstream Partners, LP in favor of Bank of America, N.A., as Administrative Agent, and the lenders from time to time party to the Term Loan Agreement, dated as of December 11, 2018 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).

10.12		—	Guaranty Agreement, dated as of January 25, 2019, by EnLink Midstream Partners, LP in favor of Bank of America, N.A., as Administrative Agent, for the ratable benefit of the lenders from time to time party to the Term Loan Agreement, dated as of December 11, 2018 (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
10.13	†	—	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.14	†	—	Form of Performance Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.15	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.16	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.17	†	—	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.18	†	—	Form of Performance Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.19	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.20	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.21	†	—	Preferred Restructuring Agreement, dated as of October 21, 2018, by and among Enfield Holdings, L.P., TPG VII Management, LLC, WSEP Egypt Holdings, LP, WSIP Egypt Holdings, LP, EnLink Midstream, LLC, EnLink Midstream Manager, LLC, EnLink Midstream Partners, LP, and EnLink Midstream GP, LLC (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
10.22		—	Contribution Agreement, dated as of January 31, 2019, by and between EnLink Midstream, LLC and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 31, 2019, filed with the Commission on February 4, 2019, file No. 001-36340).
21.1	*	—	List of Subsidiaries.
31.1	*	—	Certification of the Principal Executive Officer.
31.2	*	—	Certification of the Principal Financial Officer.
32.1	*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Partnership pursuant to 18 U.S.C. Section 1350.
101	*	—	The following financial information from EnLink Midstream Partners, LP's Annual Report on Form 10-K for the year ended December 31, 2018, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2018, 2017, and 2016, (ii) Consolidated Balance Sheets as of December 31, 2018 and 2017, (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017, and 2016, (iv) Consolidated Statements of Changes in Partners' Equity for the years ended December 31, 2018, 2017, and 2016 and (v) the Notes to Consolidated Financial Statements.

* Filed herewith.

** In accordance with the instruction on Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1, 2.2, and 2.3 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

† As required by Item 15(a)(3), this Exhibit is identified as a compensatory benefit plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EnLink Midstream Partners, LP

By: EnLink Midstream GP, LLC, its general partner

February 20, 2019

By: /s/ MICHAEL J. GARBERDING

Michael J. Garberding,

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the dates indicated by the following persons on behalf of the Registrant and in the capacities with EnLink Midstream GP, LLC, general partner of the Registrant, indicated.

Signature	Title	Date
/s/ MICHAEL J. GARBERDING Michael J. Garberding	President, Chief Executive Officer, and Director (Principal Executive Officer)	February 20, 2019
/s/ BARRY E. DAVIS Barry E. Davis	Executive Chairman and Director	February 20, 2019
/s/ ALAINA K. BROOKS Alaina K. Brooks	Executive Vice President, Chief Legal and Administrative Officer, Secretary, and Director	February 20, 2019
/s/ ERIC D. BATCHELDER Eric D. Batchelder	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 20, 2019

Exhibit 10.5

SCHEDULE A

PERFORMANCE GOAL, PERFORMANCE PERIOD, AND PAYOUT AMOUNTS

1. Performance Period. The maximum number of Restricted Incentive Units, which can vest pursuant to the Subject Award shall be calculated based on the Performance Goal over a period (the "***Performance Period***") that begins on _______ and ends on _______ (the "***Vesting Date***"). The portion of the Performance Period that commences as of the beginning of the Performance Period and ends on January 24, 2019 is referred to herein as the "***Pre-Merger Period***" and the portion of the Performance Period that commences as of January 25, 2019 and ends on the last day of the Performance Period is referred to herein as the "***Post-Merger Period***".

2. Performance Goal. The Performance Goal is based on total shareholder return ("***TSR***"), which shall be the rate of return a holder of a common equity security of a company would receive through common equity security price changes and the assumed reinvestment of dividends / distributions over the Performance Period. Pursuant to Paragraph 5 below, vesting shall be based on the ranking of the TSR of EnLink Midstream Partners, LP ("***ENLK***") and EnLink Midstream, LLC ("***ENLC***") relative to the TSR of each of the Peer Companies (identified in subparagraphs 3(b) and (c) below). At the end of the Performance Period and subject to Paragraph 5 below, the following formula shall be used to determine the TSR for each Peer Company and EnLink (as defined in Paragraph 5 below):

$$\text{TSR} = \frac{(\text{Closing Average Value} - \text{Opening Average Value}) + \text{Reinvested Dividends}}{\text{Opening Average Value}^{*}}$$

*The result shall be rounded to the nearest hundredth of one percent (.01%).

(a) The term "***Closing Average Value*** " means the average value of the common equity security on the relevant United States stock market (NYSE or NASDAQ) for the 30 trading days ending on the last day of the Pre-Merger Period or Post-Merger Period, as applicable, which shall be calculated as follows: (i) determine the closing price of the common equity security on each trading date during the 30-day period and (ii) average the amounts so determined for the 30-day period. For the avoidance of doubt, Closing Average Value for the Peer Companies will be calculated using the 30 trading days ending on the last day of the Post-Merger Period.

(b) The term "***Opening Average Value***" means the average value of the common equity security on the relevant United States stock market (NYSE or NASDAQ) for the 30 trading days preceding the start of the Pre-Merger Period or Post-Merger Period, as applicable, which shall be calculated as follows: (i) determine the closing price of the common equity security on each trading date during the 30-day period and (ii) average the amounts so determined for the 30-day period. For the avoidance of doubt, Opening Average Value for the Peer Companies will be calculated using the 30 trading days preceding the start of the Pre-Merger Period.

(c) "***Reinvested Dividends***" shall be calculated by multiplying (i) the aggregate number of common equity securities (including fractional units thereof) that could have been purchased during the Pre-Merger Period and/or Post-Merger Period, as applicable, had each cash dividend or distribution paid on a single common equity security during that period been immediately reinvested in additional common equity securities (or fractional units thereof) at the closing selling price per common equity security on the applicable dividend or distribution payment date by (ii) the average daily closing price per common equity security on the relevant United States stock market (NYSE or NASDAQ) calculated for the relevant duration of the Pre-

Merger Period and/or Post-Merger Period, as applicable, following the dividend or distribution payment date. For the avoidance of doubt, Reinvested Dividends for the Peer Companies will be calculated with respect to the entire Performance Period.

(d) Each of the foregoing amounts shall be equitably adjusted for stock / unit splits, stock dividends or unit distributions, recapitalizations and other similar events affecting the common equity securities in question without the issuer's receipt of consideration.

3. Vesting Schedule. The Restricted Incentive Units shall vest pursuant to this Agreement based on EnLink's relative TSR ranking in respect of the Performance Period as compared to the TSR ranking of the Peer Companies, in accordance with the following schedule:

Performance Level	EnLink's Achieved TSR Percentile Position Relative to AMZ Peers*	Associated Individual Payout Level (expressed as a percentage of the Subject Award)
Below Threshold	Less than 25%	0%
Threshold	Equal to 25%	50%
Target	Equal to 50%	100%
Maximum	Greater than or Equal to 75%	200%

* If EnLink's achieved TSR percentile position is between the Threshold and Target performance levels or if EnLink's achieved TSR percentile position is between the Target and Maximum performance levels, then the associated individual payout level will be interpolated on a linear basis.

(a) If EnLink's final TSR value is equal to the TSR value of a Peer Company, the Committee When applicable, references to the Committee in this Sample Amendment will relate to the "Special Committee" described in the award agreements made under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan. shall assign EnLink the higher ranking.

(b) The Peer Companies are the companies that comprise the Alerian MLP Index for Master Limited Partnerships (AMZ) as of the Grant Date, which are set forth on Schedule B to this Agreement, it being understood that in no event shall the Peer Companies include ENLC or ENLK.

(c) The Peer Companies will be subject to change as follows:

(i) In the event of a merger, acquisition or business combination transaction of a Peer Company, in which the Peer Company is the surviving entity and remains publicly traded, the surviving entity shall remain a Peer Company. Any entity involved in the transaction that is not the surviving company shall no longer be a Peer Company.

(ii) If a Peer Company ceases to be a publicly traded company at any time during the Performance Period due to bankruptcy, delisting or any other reason other than those set forth in clause (i) above, such company shall remain a Peer Company but shall be deemed to have a TSR of negative 100% (-100%).

4. General Vesting Terms . Any fractional Restricted Incentive Units resulting from the vesting of the Restricted Incentive Units in accordance with this Agreement shall be rounded down to the nearest whole number. Any portion of the Restricted Incentive Units that does not vest as of the end of the Performance Period shall be forfeited as of the end of the Performance Period.

5. TSR Determinations.

(a) *Definitions*. For purposes of the determinations set forth below:

(i) The term "***EnLink***" means (x) Pre-Merger EnLink with respect to any determinations hereunder that are limited to the Pre-Merger Period, (y) Post-Merger EnLink with respect to any determinations hereunder that are limited to the Post-Merger Period, and (z) Pre-Merger EnLink and Post-Merger EnLink with respect to any determinations hereunder that relate to the entire Performance Period;

(ii) The term "***Post-Merger EnLink***" means ENLC; and

(iii) The term "***Pre-Merger EnLink***" means ENLC and ENLK.

(b) *Initial EnLink TSR Determinations*. At the end of the Performance Period, the following TSR determinations shall be made with respect to Pre-Merger EnLink and Post-Merger EnLink as follows:

(i) The TSR for each of ENLC and ENLK shall be separately determined for the Pre-Merger Period, and the sum of the TSR for each of ENLC and ENLK shall be divided by two (2) to yield the average TSR for ENLC and ENLK for such period (the "***Pre-Merger EnLink TSR***"); and

(ii) The TSR for Post-Merger EnLink shall be determined for the Post-Merger Period (the "***Post-Merger EnLink TSR***").

(c) *Weighted Average EnLink TSR Determination*. After the determinations set forth in the preceding subparagraph (b) have been made, the following weighted average TSR determinations shall be made with respect to the entire Performance Period:

(i) The Pre-Merger EnLink TSR shall be multiplied by the following fraction: (x) the numerator of which is the number of days during the Pre-Merger Period, and (y) the denominator of which is the total number of days in the Performance Period (the result being the "***Pre-Merger Weighted EnLink TSR***");

(ii) The Post-Merger EnLink TSR shall be multiplied by the following fraction: (x) the numerator of which is the number of days during the Post-Merger Period, and (y) the denominator of which is the total number of days in the Performance Period (the result being the "***Post-Merger Weighted EnLink TSR***"); and

(iii) The Pre-Merger Weighted EnLink TSR shall be added to the Post-Merger Weighted EnLink TSR to determine the relevant TSR of EnLink with respect to the entire Performance Period and for purposes of establishing "EnLink's Achieved TSR Percentile Position Relative to AMZ Peers" pursuant to the chart set forth in Paragraph 3.

(d) *Peer Company TSR Determinations*. At the end of the Performance Period, the TSR determinations shall be made for the Peer Companies with respect to the entire Performance Period (i.e., the combined period that includes the Pre-Merger Period and the Post-Merger Period) and for purposes of establishing "EnLink's Achieved TSR Percentile Position Relative to AMZ Peers" pursuant to the chart set forth in Paragraph 3.

Exhibit 21.1

List of Subsidiaries

Name of Subsidiary	State of Organization
Acacia Natural Gas, L.L.C.	Delaware
Appalachian Oil Purchasers, LLC	Delaware
Ascension Pipeline Company, LLC	Delaware
Bridgeline Holdings, L.P.	Delaware
Cedar Cove Midstream LLC	Delaware
Chandeleur Pipe Line, LLC	Delaware
Coronado Midstream LLC	Texas
Delaware G&P, LLC	Delaware
Delaware Processing LLC	Delaware
EnLink Appalachian Compression, LLC	Delaware
EnLink Calcasieu, LLC	Delaware
EnLink Crude Marketing, LLC	Delaware
EnLink Crude Oil, Inc.	Texas
EnLink Crude Pipeline, LLC	Delaware
EnLink Crude Purchasing LLC	Texas
EnLink Delaware Crude Pipeline, LLC	Texas
EnLink Energy GP, LLC	Delaware
EnLink Gas Marketing, LP	Texas
EnLink GOM, LLC	Delaware
EnLink LIG Liquids, LLC	Louisiana
EnLink LIG, LLC	Louisiana
EnLink Louisiana Gathering, LLC	Louisiana
EnLink Matli Holdings, LLC	Delaware
EnLink Midstream Finance Corporation	Delaware
EnLink Midstream Holdings GP, LLC	Delaware
EnLink Midstream Holdings, LP	Delaware
EnLink Midstream Operating GP, LLC	Delaware
EnLink Midstream Operating, LP	Delaware
EnLink Midstream Services, LLC	Texas
EnLink NGL Marketing, LP	Texas
EnLink NGL Pipeline, LP	Texas
EnLink Nominee Corp.	Delaware
EnLink North Texas Gathering, LP	Texas
EnLink Ohio Compression, LLC	Delaware
EnLink Oklahoma Crude Gathering, LLC	Delaware
EnLink Oklahoma Gas Processing, LP	Delaware
EnLink Oklahoma Pipeline, LLC	Delaware
EnLink ORV Holdings, Inc.	Delaware
EnLink Pelican, LLC	Delaware
EnLink Permian, LLC	Texas
EnLink Permian II, LLC	Texas
EnLink Processing Services, LLC	Delaware
EnLink Texas NGL Pipeline, LLC	Texas
EnLink Texas Processing, LP	Texas
EnLink Tuscaloosa, LLC	Louisiana
Gulf Coast Fractionators	Texas
Kentucky Oil Gathering, LLC	Delaware
Ohio Oil Gathering II, LLC	Delaware
Ohio Oil Gathering III, LLC	Delaware
Ohio River Valley Pipeline, LLC	Delaware
OOGC Disposal Company I, LLC	Delaware
Sabine Hub Services LLC	Delaware
Sabine Pass Plant Facility Joint Venture	Texas
Sabine Pipe Line LLC	Delaware
SWG Pipeline, L.L.C.	Texas
TOMPC LLC	Delaware
TOM-STACK, LLC	Delaware
Victoria Express Pipeline, L.L.C.	Texas
West Virginia Oil Gathering, LLC	Delaware

Exhibit 31.1

CERTIFICATIONS

I, Michael J. Garberding, certify that:

1. I have reviewed this annual report on Form 10-K of EnLink Midstream Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2019

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING
President and Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Eric D. Batchelder, certify that:

1. I have reviewed this annual report on Form 10-K of EnLink Midstream Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2019

/s/ ERIC D. BATCHELDER

ERIC D. BATCHELDER
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of EnLink Midstream Partners, LP (the "Registrant") on Form 10-K of the Registrant for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Michael J. Garberding, President and Chief Executive Officer of EnLink Midstream GP, LLC, and Eric D. Batchelder, Executive Vice President and Chief Financial Officer of EnLink Midstream GP, LLC, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: February 20, 2019	/s/ MICHAEL J. GARBERDING
	Michael J. Garberding
	President and Chief Executive Officer
Date: February 20, 2019	/s/ ERIC D. BATCHELDER
	Eric D. Batchelder
	Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.