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

Form 10-Q

☒ Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 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)

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

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

Indicate by check mark 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 Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
(Do not check if a 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 ☒

As of April 26, 2018, the Registrant had 350,243,418 common units outstanding.

TABLE OF CONTENTS

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 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.
AMZ	Alerian MLP Index for Master Limited Partnerships.
ASC	The FASB Accounting Standards Codification.
ASC 606	ASC 606, *Revenue from Contracts with Customers.*
ASU	The FASB Accounting Standards Update.
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and Marathon Petroleum in which ENLK owns a 50% interest and Marathon Petroleum 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's Garyville refinery.
Bbls	Barrels.
Bcf	Billion cubic feet.
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.
Devon	Devon Energy Corporation.
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.
ENLC	EnLink Midstream, LLC.
ENLK	EnLink Midstream Partners, LP or EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the "Partnership."
EnLink Oklahoma T.O.	EnLink Oklahoma Gas Processing, LP or EnLink Oklahoma Gas Processing, LP together with, when applicable, its consolidated subsidiaries. EnLink Oklahoma T.O. is a partnership in which ENLK and ENLC hold an approximately 84% and 16% interest, respectively.
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. ENLK is entitled to the economic benefits and burdens of Devon's 38.75% ownership interest in GCF, which owns an NGL fractionator in Mont Belvieu, Texas.
Greater Chickadee	Crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin.
Gross Operating Margin	A non-GAAP financial measure. See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures" for the definition and other information.
HEP	Howard Energy Partners. ENLK sold its 31% ownership interest in HEP in March 2017.
ISDAs	International Swaps and Derivatives Association Agreements.
Marathon Petroleum	A subsidiary of Marathon Petroleum Company and ENLK's joint venture partner in the Ascension JV.
Mcf	Thousand cubic feet.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP, an affiliate of ENLK's joint venture partner in the Delaware Basin JV.
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.

Partnership	EnLink Midstream Partners, LP or EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as “ENLK.”
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins in West Texas.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Series B Preferred Units	Series B Cumulative Convertible Preferred Units.
Series C Preferred Units	Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.
VEX	Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in South Texas.

Table of Contents

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	March 31, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16.8	$ 30.8
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3 and $0.3, respectively	78.3	50.1
Accrued revenue and other	598.6	576.6
Related party	115.8	102.7
Fair value of derivative assets	4.1	6.8
Natural gas and NGLs inventory, prepaid expenses, and other	32.2	39.7
Total current assets	845.8	806.7
Property and equipment, net of accumulated depreciation of $2,639.3 and $2,533.0, respectively	6,659.1	6,587.0
Intangible assets, net of accumulated amortization of $329.5 and $298.7, respectively	1,466.3	1,497.1
Goodwill	422.3	422.3
Investment in unconsolidated affiliates	86.4	89.4
Other assets, net	12.4	11.5
Total assets	$ 9,492.3	$ 9,414.0
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 86.2	$ 66.9
Accounts payable to related party	16.0	18.4
Accrued gas, NGLs, condensate, and crude oil purchases	494.7	476.1
Fair value of derivative liabilities	8.5	8.4
Installment payable, net of discount of $0.5 at December 31, 2017	—	249.5
Other current liabilities	221.0	222.4
Total current liabilities	826.4	1,041.7
Long-term debt	3,838.8	3,467.8
Asset retirement obligations	14.3	14.2
Other long-term liabilities	29.3	33.9
Deferred tax liability	46.3	46.3
Fair value of derivative liabilities	0.7	—
Redeemable non-controlling interest	4.6	4.6
Partners' equity:		
Common unitholders (350,233,987 and 349,702,372 units issued and outstanding, respectively)	2,678.2	2,791.6
Series B preferred unitholders (57,469,939 and 57,056,281 units issued and outstanding, respectively)	870.0	864.1
Series C preferred unitholders (400,000 units outstanding)	401.1	395.1
General partner interest (1,594,974 equivalent units outstanding)	206.9	207.3
Accumulated other comprehensive loss	(2.1)	(2.1)
Non-controlling interest	577.8	549.5
Total partners' equity	4,731.9	4,805.5
Total liabilities and partners' equity	$ 9,492.3	$ 9,414.0

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(Unaudited)	
Revenues:		
Product sales	$ 1,499.2	$ 990.0
Product sales—related parties	3.6	42.7
Midstream services	92.2	127.4
Midstream services—related parties	166.2	159.0
Gain on derivative activity	0.5	2.8
Total revenues	1,761.7	1,321.9
Operating costs and expenses:		
Cost of sales (1)	1,381.5	1,002.3
Operating expenses	109.2	104.1
General and administrative	26.2	35.0
Loss on disposition of assets	0.1	5.1
Depreciation and amortization	138.1	128.3
Impairments	—	7.0
Gain on litigation settlement	—	(17.5)
Total operating costs and expenses	1,655.1	1,264.3
Operating income	106.6	57.6
Other income (expense):		
Interest expense, net of interest income	(43.7)	(44.5)
Income from unconsolidated affiliates	3.0	0.7
Other income	0.2	—
Total other expense	(40.5)	(43.8)
Income before non-controlling interest and income taxes	66.1	13.8
Income tax provision	(1.0)	(0.5)
Net income	65.1	13.3
Net income (loss) attributable to non-controlling interest	5.0	(4.8)
Net income attributable to ENLK	$ 60.1	$ 18.1
General partner interest in net income	$ 10.6	$ 5.9
Limited partners' interest in net income (loss) attributable to ENLK	$ 21.6	$ (9.3)
Series B preferred interest in net income attributable to ENLK	$ 21.9	$ 21.5
Series C preferred interest in net income attributable to ENLK	$ 6.0	$ —
Net income (loss) attributable to ENLK per limited partners' unit:		
Basic common unit	$ 0.06	$ (0.03)
Diluted common unit	$ 0.06	$ (0.03)

(1) Includes related party cost of sales of $34.1 million and $28.7 million for the three months ended March 31, 2018 and 2017, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statement of Changes in Partners' Equity
Three Months Ended March 31, 2018
(In millions)

	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	$	$	$	$
						(Unaudited)						
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	0.9	0.1	—	—	—	—	—	—	—	—	0.9	—
Conversion of restricted units for common units, net of units withheld for taxes	(2.7)	0.4	—	—	—	—	—	—	—	—	(2.7)	—
Unit-based compensation	4.4	—	—	—	—	—	4.4	—	—	—	8.8	—
Distributions	(137.6)	—	(16.0)	0.4	—	—	(15.4)	—	—	(10.0)	(179.0)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	33.3	33.3	—
Net income	21.6	—	21.9	—	6.0	—	10.6	—	—	5.0	65.1	—
Balance, March 31, 2018	$ 2,678.2	350.2	$ 870.0	57.5	$ 401.1	0.4	$ 206.9	1.6	$ (2.1)	$ 577.8	$ 4,731.9	$ 4.6

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 65.1	$ 13.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Impairments	—	7.0
Depreciation and amortization	138.1	128.3
Non-cash unit-based compensation	5.1	19.3
Gain on derivatives recognized in net income	(0.5)	(2.8)
Cash settlements on derivatives	3.1	(2.9)
Amortization of debt issue costs, net (premium) discount of notes and installment payable	1.5	7.2
Distribution of earnings from unconsolidated affiliates	4.6	0.1
Income from unconsolidated affiliates	(3.0)	(0.7)
Other operating activities	0.3	5.0
Changes in assets and liabilities, net of assets acquired and liabilities assumed:		
Accounts receivable, accrued revenue, and other	(63.3)	17.1
Natural gas and NGLs inventory, prepaid expenses, and other	7.7	2.3
Accounts payable, accrued gas and crude oil purchases, and other accrued liabilities	34.0	(19.0)
Net cash provided by operating activities	192.7	174.2
Cash flows from investing activities:		
Additions to property and equipment	(181.5)	(256.3)
Proceeds from sale of unconsolidated affiliate investment	—	189.7
Investment in unconsolidated affiliates	—	(6.0)
Distribution from unconsolidated affiliates in excess of earnings	1.4	2.8
Other investing activities	0.8	0.5
Net cash used in investing activities	(179.3)	(69.3)
Cash flows from financing activities:		
Proceeds from borrowings	795.0	793.0
Payments on borrowings	(425.0)	(583.0)
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	(250.0)
Proceeds from issuance of common units	0.9	55.2
Distributions to non-controlling interests	(10.0)	(3.3)
Contributions by non-controlling interests, including contributions from affiliates of $10.6 and $20.1, respectively	33.3	40.9
Distributions to Series B Preferred Units	(16.0)	—
Distributions to common unitholders and to general partner	(153.0)	(149.6)
Other financing activities	(2.6)	(4.9)
Net cash used in financing activities	(27.4)	(101.7)
Net increase (decrease) in cash and cash equivalents	(14.0)	3.2
Cash and cash equivalents, beginning of period	30.8	11.6
Cash and cash equivalents, end of period	$ 16.8	$ 14.8
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 14.8	$ 15.6
Cash paid for income taxes	$ —	$ 2.4
Non-cash accrual of property and equipment	$ 0.3	$ 8.2

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements
March 31, 2018
(Unaudited)

(1) General

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 EnLink Oklahoma T.O.

Please read the notes to the consolidated financial statements in conjunction with the Definitions page set forth in this report prior to Part I—Financial Information.

(a) Organization of Business

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol "ENLK." Our business activities are conducted through our subsidiary, 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 an indirect, wholly-owned subsidiary of ENLC. ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." Devon owns ENLC's managing member and common units representing approximately 64% of the outstanding limited liability company interests in ENLC.

(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.

We connect the wells of producers in our market areas to our gathering systems, which consist of networks of pipelines that collect natural gas from points 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, other markets, 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, iso-butane, 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 each transaction is the use of our assets to transport a product or provide a processed product to an end-user or other marketer or pipeline at the tailgate of the plant, barge terminal, or pipeline.

(2) Significant Accounting Policies

(a) ***Basis of Presentation***

The accompanying consolidated financial statements are prepared in accordance with the instructions to Form 10-Q, are unaudited, and do not include all the information and disclosures required by GAAP for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. All significant intercompany balances and transactions have been eliminated in consolidation.

(b) 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 each transaction is the use of our assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal, or pipeline. 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*—Product 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 as 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 service 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 three months ended March 31, 2018, the reclassification of revenues and cost of sales resulted in a net decrease in revenue of approximately $138 million, or 7%, 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
Product sales	$ (32)
Product sales—related parties	(22)
Midstream services	(77)
Midstream services—related parties	(7)
Total	$ (138)

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 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

(“WASP”) 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 service 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 service revenues 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 revenues 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, 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 revenues.

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 revenues.

The following table summarizes the expected gross operating margin (in millions), 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.

2018 (remaining)	$	616.4
2019		254.3
2020		241.1
2021		98.4
2022		89.5
Thereafter		228.2
Total	$	1,527.9

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 three months ended March 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 11 for the revenue disaggregation information included in the segment information table for the three months ended March 31, 2018. As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the three months ended March 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.

(c) 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. Early adoption is permitted. Entities are required to adopt ASC 842 using a modified retrospective transition. We are currently assessing the impact of adopting ASC 842. This assessment includes the evaluation of our current lease contracts and the analysis of contracts that may contain lease components. While we cannot currently estimate the quantitative effect that ASC 842 will have on our consolidated financial statements, the adoption of ASC 842 will increase our asset and liability balances on the consolidated balance sheets 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 addition, there are industry-specific concerns with the implementation of ASC 842 that will require further evaluation before we are able to fully assess the impact of ASC 842 on our consolidated financial statements.

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.

(d) Property & Equipment

Impairment Review. In accordance with ASC 360, *Property, Plant and Equipment*, we evaluate long-lived assets of identifiable business activities for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset's carrying value over its fair value. For the three months ended March 31, 2017, we recognized impairments of property and equipment of $7.0 million, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

(3) 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 10 to 20 years.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Three Months Ended March 31, 2018			
Customer relationships, beginning of period	$ 1,795.8	$ (298.7)	$ 1,497.1
Amortization expense	—	(30.8)	(30.8)
Customer relationships, end of period	$ 1,795.8	$ (329.5)	$ 1,466.3

The weighted average amortization period is 15.0 years. Amortization expense was $30.8 million and $29.5 million for the three months ended March 31, 2018 and 2017, respectively.

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

2018 (remaining)	$ 92.6
2019	123.4
2020	123.4
2021	123.4
2022	123.4
Thereafter	880.1
Total	$ 1,466.3

(4) Related Party Transactions

We engage in various transactions with Devon and other related parties. For the three months ended March 31, 2018 and 2017, Devon accounted for 9.8% and 14.9% of our revenues, respectively. We had an accounts receivable balance related to transactions with Devon of $115.1 million at March 31, 2018 and $102.7 million at December 31, 2017. Additionally, we had an accounts payable balance related to transactions with Devon of $16.0 million at March 31, 2018 and $16.3 million at December 31, 2017.

For the three months ended March 31, 2018 and 2017, we recorded cost of sales of $13.0 million and $1.2 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.

Management believes these transactions are executed on terms that are fair and reasonable. The amounts related to related party transactions are specified in the accompanying consolidated financial statements.

(5) Long-Term Debt

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

	March 31, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Credit facility due 2020 (1)	$ 370.0	$ —	$ 370.0	$ —	$ —	$ —
2.70% Senior unsecured notes due 2019	400.0	(0.1)	399.9	400.0	(0.1)	399.9
4.40% Senior unsecured notes due 2024	550.0	2.1	552.1	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	(0.6)	499.4	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	(6.4)	443.6	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	$ 3,870.0	$ (6.2)	3,863.8	$ 3,500.0	$ (6.3)	3,493.7
Debt issuance cost (2)			(25.0)			(25.9)
Long-term debt, net of unamortized issuance cost			$ 3,838.8			$ 3,467.8

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.3% at March 31, 2018.
(2) Net of amortization of $12.9 million and $12.0 million at March 31, 2018 and December 31, 2017, respectively.

Credit Facility

We have a $1.5 billion unsecured revolving credit facility that matures on March 6, 2020, which includes a$500.0 million letter of credit subfacility. Under our credit facility, we are permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under our credit facility by an additional amount not to exceed $500.0 million and (2) subject to certain conditions and the consent of the requisite lenders, ontwo separate occasions, extend the maturity date of our credit facility by one year on each occasion. Our credit facility contains certain financial, operational, and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (which is defined in our credit facility and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under our credit facility bear 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 vary depending on our credit rating. If we breach certain covenants governing our credit facility, amounts outstanding under our credit facility, if any, may become due and payable immediately. At March 31, 2018, we were in compliance and expect to be in compliance with the covenants in our credit facility for at least the next twelve months.

As of March 31, 2018, there were $9.8 million in outstanding letters of credit and $370.0 million outstanding borrowings under our credit facility, leaving approximately $1.1 billion available for future borrowing.

All other material terms and conditions of our credit facility and outstanding senior unsecured note issuances are described in Part II, "Item 8. Financial Statements and Supplementary Data—Note 6" in our Annual Report on Form 10-K for the year endedDecember 31, 2017.

(6) Partners' Capital

(a) Issuance of Common Units

In August 2017, we entered into the 2017 EDA 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. We may also sell common units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of the common units under the 2017 EDA and may at any time suspend solicitation and offers under the 2017 EDA.

For the three months ended March 31, 2018, we sold an aggregate of approximately 0.1 million common units under the 2017 EDA, generating proceeds of approximately $0.9 million (net of less than $0.1 million of commissions paid to the Sales Agents). We used the net proceeds for general partnership purposes. As of March 31, 2018, approximately $564.5 million remains available to be issued under the 2017 EDA.

(b) 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. 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 three months ended March 31, 2018 and 2017, $21.9 million and $21.5 million of income, respectively, was allocated to the Series B Preferred Units.

A summary of the distribution activity relating to the Series B Preferred Units for the three months ended March 31, 2018 and 2017 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash Distribution (in millions)	Date paid/payable
2018			
Fourth Quarter of 2017	413,658	$ 16.0	February 13, 2018
First Quarter of 2018	416,657	$ 16.2	May 14, 2018
2017			
Fourth Quarter of 2016	1,130,131	$ —	February 13, 2017
First Quarter of 2017	1,154,147	$ —	May 12, 2017

(c) Series C Preferred Units

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 distribution rate in effect for the Series C Preferred Units for the three months ended March 31, 2018 was 6.0% per annum. Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period. For the three months ended March 31, 2018, $6.0 million of income was allocated to the Series C Preferred Units.

(d) Common Unit Distributions

Unless restricted by the terms of our credit facility and/or the indentures governing our senior unsecured notes, we must make distributions of 100% of available cash, as defined in our partnership agreement, within 45 days following the end of each quarter. Distributions are made to our general partner in accordance with its current percentage interest with the remainder to the common unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The general partner is not entitled to 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.

Our general partner owns the general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in the partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23.0% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

A summary of the distribution activity relating to the common units for the three months ended March 31, 2018 and 2017 is provided below:

Declaration period	Distribution/unit	Date paid/payable
2018		
Fourth Quarter of 2017	$ 0.39	February 13, 2018
First Quarter of 2018	$ 0.39	May 14, 2018
2017		
Fourth Quarter of 2016	$ 0.39	February 13, 2017
First Quarter of 2017	$ 0.39	May 12, 2017

(e) 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):

	Three Months Ended March 31,	
	2018	2017
Limited partners' interest in net income (loss)	$ 21.6	$ (9.3)
Distributed earnings allocated to:		
Common units (1)	$ 136.5	$ 134.0
Unvested restricted units (1)	0.8	0.9
Total distributed earnings	$ 137.3	$ 134.9
Undistributed loss allocated to:		
Common units	$ (115.0)	$ (143.2)
Unvested restricted units	(0.7)	(1.0)
Total undistributed loss	$ (115.7)	$ (144.2)
Net income (loss) allocated to:		
Common units	$ 21.5	$ (9.2)
Unvested restricted units	0.1	(0.1)
Total limited partners' interest in net income (loss)	$ 21.6	$ (9.3)
Basic and diluted net income (loss) per unit:		
Basic	$ 0.06	$ (0.03)
Diluted	$ 0.06	$ (0.03)

(1) For the three months ended March 31, 2018 and 2017, distributed earnings represent a declared distribution of $0.39 per unit payable on May 14, 2018 and a distribution of $0.39 per unit paid on May 12, 2017, respectively.

The following are the unit amounts used to compute the basic and diluted earnings per unit for the periods presented (in millions):

	Three Months Ended March 31,	
	2018	2017
Basic weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	350.1	343.6
Diluted weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	350.1	343.6
Dilutive effect of non-vested restricted units (1)	1.0	—
Total weighted average limited partner diluted common units outstanding	351.1	343.6

(1) All common unit equivalents were antidilutive for the three months ended March 31, 2017 because the limited partners were allocated a net loss. The Series B Preferred Units were also antidilutive for the three months ended March 31, 2018.

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 periods presented.

Net income is allocated to our general partner in an amount equal to its incentive distribution rights as described in section “(d) Common Unit Distributions” above.Our general partner’s share of net income consists of incentive distribution rights to the extent earned, a deduction for unit-based compensation attributable to ENLC’s restricted units, and the percentage interest of our net income adjusted for ENLC’s unit-based compensation specifically allocated toour general partner. The net income allocated to our general partner is as follows (in millions):

	Three Months Ended March 31,	
	2018	2017
Income allocation for incentive distributions	$ 14.8	$ 14.7
Unit-based compensation attributable to ENLC’s restricted units	(4.4)	(8.8)
General partner share of net income	0.2	—
General partner interest in net income	$ 10.6	$ 5.9

(7) Investment in Unconsolidated Affiliates

Our unconsolidated investments consist of a contractual right to the economic benefits and burdens associated with Devon’s38.75% ownership interest in GCF and an approximate 30% ownership in the Cedar Cove JV.

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

	Three Months Ended March 31,	
	2018	2017
GCF		
Distributions	$ 5.7	$ 2.7
Equity in income	$ 4.6	$ 4.0
HEP		
Equity in loss (1)	$ —	$ (3.4)
Cedar Cove JV		
Contributions	$ —	$ 6.0
Distributions	$ 0.3	$ 0.2
Equity in income (loss)	$ (1.6)	$ 0.1
Total		
Contributions	$ —	$ 6.0
Distributions	$ 6.0	$ 2.9
Equity in income (1)	$ 3.0	$ 0.7

(1) We finalized the sale of our ownership interest in HEP during the first quarter of 2017, resulting in a loss of $3.4 million for the three months ended March 31, 2017.

The following table shows the balances related to our investment in unconsolidated affiliates as ofMarch 31, 2018 and December 31, 2017 (in millions):

	March 31, 2018	December 31, 2017
GCF	$ 47.3	$ 48.4
Cedar Cove JV	39.1	41.0
Total investment in unconsolidated affiliates	$ 86.4	$ 89.4

(8) Employee Incentive Plans

(a) Long-Term Incentive Plans

We and ENLC each have similar unit-based compensation payment plans for officers and employees. We grant 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").

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 and EnLink Oklahoma T.O.Amounts recognized on the consolidated financial statements with respect to these plans are as follows (in millions):

	Three Months Ended March 31,	
	2018	2017
Cost of unit-based compensation charged to operating expense	$ 2.0	$ 5.0
Cost of unit-based compensation charged to general and administrative expense	3.1	14.3
Total unit-based compensation expense	$ 5.1	$ 19.3

(b) EnLink Midstream Partners, LP 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 dateA summary of the restricted incentive unit activity for the three months ended March 31, 2018 is provided below:

	Three Months Ended March 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)	938,306	15.02
Vested (1)(2)	(574,624)	22.32
Forfeited	(124,301)	11.83
Non-vested, end of period	2,219,605	$ 13.97
Aggregate intrinsic value, end of period (in millions)	$ 30.3	

(1) Restricted incentive units typically vest at the end of three years. In March 2018, we 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 included 181,959 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 three months ended March 31, 2018 and 2017 is provided below (in millions):

	Three Months Ended March 31,	
EnLink Midstream Partners, LP Restricted Incentive Units:	**2018**	**2017**
Aggregate intrinsic value of units vested	$ 8.7	$ 15.3
Fair value of units vested	$ 12.8	$ 20.5

As of March 31, 2018, there was $19.9 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 2.2 years.

(c) EnLink Midstream Partners, LP Performance Units

Our general partner grants performance awards under the GP 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 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 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 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 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. 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. 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 of performance units granted and the related assumptions by performance unit grant date:

EnLink Midstream Partners, LP Performance Units:	March 2018
Beginning TSR price	$ 15.44
Risk-free interest rate	2.38 %
Volatility factor	43.85 %
Distribution yield	10.5 %

The following table presents a summary of the performance units:

	Three Months Ended March 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)	(115,328)	35.39
Forfeited	(76,351)	16.62
Non-vested, end of period	649,951	$ 17.83
Aggregate intrinsic value, end of period (in millions)	$ 8.9	

(1) Vested units included 34,069 units withheld for payroll taxes paid on behalf of employees.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

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 three months ended March 31, 2018 is provided below (in millions):

	Three Months Ended March 31,
EnLink Midstream Partners, LP Performance Units:	**2018**
Aggregate intrinsic value of units vested	$ 2.0
Fair value of units vested	$ 4.1

As of March 31, 2018, there was $8.3 million of unrecognized compensation cost that related to non-vested ENLK performance units. That cost is expected to be recognized over a weighted-average period of 2.3 years.

(d) EnLink Midstream, LLC 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 three months ended March 31, 2018 is provided below:

	Three Months Ended March 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)	838,734	15.51
Vested (1)(2)	(531,143)	24.60
Forfeited	(114,795)	11.75
Non-vested, end of period	2,082,106	$ 14.14
Aggregate intrinsic value, end of period (in millions)	$ 30.5	

(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 included 171,813 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 three months ended March 31, 2018 and 2017 is provided below (in millions):

	Three Months Ended March 31,	
EnLink Midstream, LLC Restricted Incentive Units:	**2018**	**2017**
Aggregate intrinsic value of units vested	$ 8.9	$ 14.3
Fair value of units vested	$ 13.1	$ 20.4

As of March 31, 2018, there was $18.7 million of unrecognized compensation cost related to non-vested ENLC restricted incentive units. The cost is expected to be recognized over a weighted-average period of 2.1 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. 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
Beginning TSR price	$ 16.55
Risk-free interest rate	2.38%
Volatility factor	51.36%
Distribution yield	6.7%

The following table presents a summary of the performance units:

	Three Months Ended March 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)	(102,555)	40.48
Forfeited	(70,918)	17.75
Non-vested, end of period	599,231	$ 19.33
Aggregate intrinsic value, end of period (in millions)	$ 8.8	

(1) Vested units included 28,846 units withheld for payroll taxes paid on behalf of employees.

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 three months ended March 31, 2018 is provided below (in millions):

	Three Months Ended March 31,
EnLink Midstream, LLC Performance Units:	2018
Aggregate intrinsic value of units vested	$ 1.9
Fair value of units vested	$ 4.2

As of March 31, 2018, there was $8.3 million of unrecognized compensation cost that related to non-vested ENLC performance units. That cost is expected to be recognized over a weighted-average period of 2.3 years.

(9) 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 5.45% senior unsecured notes due 2047 (the "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. For the three months ended March 31, 2018, we amortized an immaterial amount of the settlement loss into interest expense from accumulated other comprehensive income (loss). We expect to recognize $0.1 million of interest expense out of accumulated other comprehensive income (loss) over the next twelve months. We have no open interest rate swap position as of March 31, 2018.

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Commodity swaps are used to manage and hedge price and location risk related to these market exposures. Commodity swaps are also used 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 swap transactions 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 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. They are also used to hedge the basis location price risk resulting from supply and markets being priced on different indices. For natural gas, NGLs, condensate, and crude oil, fixed-for-float swaps are used to protect cash flows against price fluctuations: (1) 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.

The components of gain (loss) on derivative activity in the consolidated statements of operations related to commodity swaps are (in millions):

	Three Months Ended March 31,	
	2018	2017
Change in fair value of derivatives	$ (3.5)	$ 5.3
Realized gain (loss) on derivatives	4.0	(2.5)
Gain on derivative activity	$ 0.5	$ 2.8

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

	March 31, 2018	December 31, 2017
Fair value of derivative assets—current	$ 4.1	$ 6.8
Fair value of derivative liabilities—current	(8.5)	(8.4)
Fair value of derivative liabilities—long-term	(0.7)	—
Net fair value of derivatives	$ (5.1)	$ (1.6)

As of March 31, 2018 and December 31, 2017, there were no derivative assets classified as long-term on the consolidated balance sheets.

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.

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 March 31, 2018 (in millions). The remaining term of the contracts extend no later than October 2019.

		March 31, 2018		
Commodity	Instruments	Unit	Volume	Fair Value
NGL (short contracts)	Swaps	Gallons	(37.6)	$ (2.3)
NGL (long contracts)	Swaps	Gallons	17.6	—
Natural Gas (short contracts)	Swaps	MMBtu	(13.2)	3.0
Natural Gas (long contracts)	Swaps	MMBtu	12.9	(5.8)
Total fair value of derivatives				$ (5.1)

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 $4.1 million as of March 31, 2018 would be reduced to $0.1 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(10) 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.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

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

	Level 2	
	March 31, 2018	December 31, 2017
Commodity Swaps (1)	$ (5.1)	$ (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 methodologiesConsiderable 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):

	March 31, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 3,838.8	$ 3,828.1	$ 3,467.8	$ 3,575.6
Installment Payables	$ —	$ —	$ 249.5	$ 249.6
Obligations under capital lease	$ 3.7	$ 3.1	$ 4.1	$ 3.4

(1) The carrying value of long-term debt is reduced by debt issuance costs of $25.0 million and $25.9 million at March 31, 2018 and December 31, 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.

We had $370.0 million of outstanding borrowings under our credit facility as of March 31, 2018 and no outstanding borrowings under our credit facility as of December 31, 2017. As borrowings under our credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under our credit facility. As of March 31, 2018 and December 31, 2017, we had total borrowings under senior unsecured notes of $3.5 billion 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 ofMarch 31, 2018 and December 31, 2017 were based on Level 2 inputs from third-party market quotations. The fair values of obligations under capital leases were calculated using Level 2 inputs from third-party banks.

(11) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served and the nature of operating activity. Our reportable segments consist of the following: natural gas gathering, processing, transmission, and fractionation operations located in North Texas and the Permian Basin primarily in West Texas ("Texas"), the 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.

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 three months ended

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

March 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
Three Months Ended March 31, 2018						
Natural gas sales	$ 83.0	$ 125.0	$ 48.1	$ —	$ —	$ 256.1
NGL sales	—	608.4	1.9	0.5	—	610.8
Crude oil and condensate sales	—	—	—	632.3	—	632.3
Product sales	83.0	733.4	50.0	632.8	—	1,499.2
Natural gas sales—related parties	—	—	0.5	—	—	0.5
NGL sales—related parties	93.0	5.6	100.1	—	(196.3)	2.4
Crude oil and condensate sales—related parties	10.9	0.1	22.3	0.1	(32.7)	0.7
Product sales—related parties	103.9	5.7	122.9	0.1	(229.0)	3.6
Gathering and transportation	13.2	17.6	15.6	0.8	—	47.2
Processing	3.8	0.6	9.0	—	—	13.4
NGL services	—	16.6	—	—	—	16.6
Crude services	—	—	0.1	12.8	—	12.9
Other services	1.8	0.2	—	0.1	—	2.1
Midstream services	18.8	35.0	24.7	13.7	—	92.2
Gathering and transportation—related parties	52.6	—	34.7	—	—	87.3
Processing—related parties	51.6	—	22.1	—	—	73.7
Crude services—related parties	—	—	0.7	4.3	—	5.0
Other services—related parties	0.2	—	—	—	—	0.2
Midstream services—related parties	104.4	—	57.5	4.3	—	166.2
Revenue from contracts with customers	310.1	774.1	255.1	650.9	(229.0)	1,761.2
Cost of sales	(161.5)	(686.7)	(139.0)	(623.3)	229.0	(1,381.5)
Operating expenses	(44.2)	(25.6)	(20.7)	(18.7)	—	(109.2)
Gain on derivative activity	—		—	—	0.5	0.5
Segment profit	$ 104.4	$ 61.8	$ 95.4	$ 8.9	$ 0.5	$ 271.0
Depreciation and amortization	$ (52.5)	$ (29.2)	$ (42.1)	$ (12.4)	$ (1.9)	$ (138.1)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 65.3	$ 6.8	$ 98.5	$ 9.3	$ 1.3	$ 181.2
Three Months Ended March 31, 2017						
Product sales	$ 85.1	$ 544.5	$ 14.5	$ 345.9	$ —	$ 990.0
Product sales—related parties	106.5	10.2	64.4	0.8	(139.2)	42.7
Midstream services	27.8	53.1	27.9	18.6	—	127.4
Midstream services—related parties	105.1	29.0	49.4	3.3	(27.8)	159.0
Cost of sales	(179.2)	(564.7)	(88.7)	(336.7)	167.0	(1,002.3)
Operating expenses	(43.9)	(25.4)	(14.1)	(20.7)	—	(104.1)
Gain on derivative activity	—	—	—	—	2.8	2.8
Segment profit	$ 101.4	$ 46.7	$ 53.4	$ 11.2	$ 2.8	$ 215.5
Depreciation and amortization	$ (49.8)	$ (28.1)	$ (36.5)	$ (11.5)	$ (2.4)	$ (128.3)
Impairments	$ —	$ —	$ —	$ (7.0)	$ —	$ (7.0)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 28.3	$ 32.7	$ 140.7	$ 37.4	$ 9.0	$ 248.1

The table below represents information about segment assets as ofMarch 31, 2018 and December 31, 2017 (in millions):

Segment Identifiable Assets:	March 31, 2018	December 31, 2017
Texas	$ 3,122.2	$ 3,094.8
Louisiana	2,366.8	2,408.5
Oklahoma	2,890.2	2,836.7
Crude and Condensate	983.8	929.5
Corporate	129.3	144.5
Total identifiable assets	$ 9,492.3	$ 9,414.0

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

	Three Months Ended March 31,	
	2018	2017
Segment profits	$ 271.0	$ 215.5
General and administrative expenses	(26.2)	(35.0)
Loss on disposition of assets	(0.1)	(5.1)
Depreciation and amortization	(138.1)	(128.3)
Impairments	—	(7.0)
Gain on litigation settlement	—	17.5
Operating income	$ 106.6	$ 57.6

(12) 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:	March 31, 2018	December 31, 2017
Natural gas and NGLs inventory	$ 22.0	$ 30.1
Prepaid expenses and other	10.2	9.6
Natural gas and NGLs inventory, prepaid expenses, and other	$ 32.2	$ 39.7

Other Current Liabilities:	March 31, 2018	December 31, 2017
Accrued interest	$ 64.0	$ 35.4
Accrued wages and benefits, including taxes	14.5	30.4
Accrued ad valorem taxes	13.2	27.8
Capital expenditure accruals	47.4	48.8
Onerous performance obligations	15.0	15.2
Other	66.9	64.8
Other current liabilities	$ 221.0	$ 222.4

Item 2. 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 Part I—Financial Information.

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 EnLink Oklahoma T.O.

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 4.8 Bcf/d of processing capacity, seven fractionators with approximately 260,000 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:

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

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering, processing, and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, STACK, and CNOW 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 our ORV crude oil, condensate, condensate stabilization, natural gas compression, and brine disposal activities in the Utica and Marcellus Shales, our crude oil operations in the Permian Basin and Central Oklahoma, and our crude oil activities associated with VEX located in the Eagle Ford Shale; and

- *Corporate Segment*. The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our contractual right to the economic benefits and burdens associated with Devon's 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 each transaction is the use of our assets to transport a product or provide a processed product to an end-user or other marketer or pipeline at the tailgate of the plant, barge terminal, or pipeline. 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 95% of our gross operating margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the three months ended March 31, 2018. We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

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 to July 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 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 March 31, 2018, the balance sheet reflects a liability of $22.4 million related to this performance obligation. 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.

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 from producers at a market index less a stated deduction, then transport and resell the crude oil and condensate at the same market index. 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 3. 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 only 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. Under margin contract arrangements, our gross operating margins are higher during periods of high NGL prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Gross operating margin results under POP contracts are impacted only by the value of the natural gas and liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts, our gross operating margins are driven by throughput volume.

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 the asset.

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

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

Central Oklahoma Crude Oil Gathering Systems. In late March 2018, we completed construction of the first phase of a new crude oil gathering system that we refer to as "Black Coyote." Black Coyote expands our operations in the core of the STACK play in Central Oklahoma and was built primarily on acreage dedicated from Devon, which is the main shipper on the system. In addition, we are further expanding our crude oil gathering operations in the STACK through the construction of the Redbud Crude Oil Gathering System ("Redbud"), which is supported by a contract with an existing large and active customer in the STACK. We expect Redbud to be operational during the second half of 2018. Both Black Coyote and Redbud are jointly owned by ENLK and ENLC through their respective ownership in EnLink Oklahoma T.O.

Lobo Natural Gas Gathering and Processing Facilities. The Lobo facilities are part of our Delaware Basin JV and are supported by long-term contracts. We are constructing an additional expansion of the Lobo II processing facility, which will increase capacity by 15 MMcf/d and is expected to be completed during the first half of 2018. We are also expanding our gas processing capacity at our Lobo facilities by 200 MMcf/d through the construction of the Lobo III cryogenic gas processing plant, which is expected to be operational around the second half of 2018.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, 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 acquisition transaction costs, accretion expense associated with asset retirement obligations, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, and income (loss) from unconsolidated affiliate investments. 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 entities may not calculate adjusted EBITDA in the same manner.

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

Reconciliation of net income (loss) to adjusted EBITDA

	Three Months Ended March 31,	
	2018	**2017**
Net income	$ 65.1	$ 13.3
Interest expense, net of interest income	43.7	44.5
Depreciation and amortization	138.1	128.3
Impairments	—	7.0
Income from unconsolidated affiliates	(3.0)	(0.7)
Distributions from unconsolidated affiliates	6.0	2.9
Loss on disposition of assets	0.1	5.1
Unit-based compensation	5.1	19.3
Income tax provision	1.0	0.5
(Gain) loss on non-cash derivatives	3.5	(5.3)
Payments under onerous performance obligation offset to other current and long-term liabilities	(4.5)	(4.5)
Other (1)	1.1	0.8
Adjusted EBITDA before non-controlling interest	$ 256.2	$ 211.2
Non-controlling interest share of adjusted EBITDA (2)	(12.5)	(3.6)
Adjusted EBITDA, net to ENLK	$ 243.7	$ 207.6

(1) Includes accretion expense associated with asset retirement obligations and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(2) Non-controlling interest share of adjusted EBITDA includes ENLC's 16.1% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA, net to the Partnership, less interest expense (excluding amortization of the EnLink Oklahoma T.O. 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 entities 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)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Net cash provided by operating activities	$ 192.7	$ 174.2
Interest expense, net (1)	42.2	37.3
Current income tax	1.0	0.8
Distributions from unconsolidated affiliate investment in excess of earnings	1.4	2.9
Other (2)	1.8	0.9
Changes in operating assets and liabilities which (provided) used cash:		
Accounts receivable, accrued revenues, inventories and other	55.6	(19.4)
Accounts payable, accrued gas and crude oil purchases and other (3)	(38.5)	14.5
Adjusted EBITDA before non-controlling interest	$ 256.2	$ 211.2
Non-controlling interest share of adjusted EBITDA (4)	(12.5)	(3.6)
Adjusted EBITDA, net to ENLK	$ 243.7	$ 207.6
Interest expense, net of interest income	(43.7)	(44.5)
Amortization of EnLink Oklahoma T.O. installment payable discount included in interest expense (5)	0.5	7.0
Litigation settlement adjustment (6)	—	(12.3)
Current taxes and other	(0.9)	(0.6)
Maintenance capital expenditures, net to ENLK (7)	(6.2)	(4.2)
Preferred unit accrued cash distributions (8)	(22.2)	—
Distributable cash flow	$ 171.2	$ 153.0

(1) Net of amortization of debt issuance costs and discount and premium, which are included in interest expense but not included in net cash provided by operating activities.

(2) Includes non-cash rent, which relates to lease incentives pro-rated over the lease term, and accruals for settled commodity swap transactions.

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

(4) Non-controlling interest share of adjusted EBITDA includes ENLC's 16.1% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.

(5) Amortization of the EnLink Oklahoma T.O. installment payable discount is considered non-cash interest under our credit facility since the payment under the payable is consideration for the acquisition of the EnLink Oklahoma T.O. assets.

(6) Represents recoveries from a lawsuit settled in 2017 for amounts not previously deducted from distributable cash flow.

(7) Excludes maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.

(8) Represents the cash distributions earned by the Series B Preferred Units of $16.2 million and $6.0 million earned by the Series C Preferred Units for the three months ended March 31, 2018. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders.

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):

	Three Months Ended March 31,	
	2018	**2017**
Operating income	$ 106.6	$ 57.6
Add (deduct):		
Operating expenses	109.2	104.1
General and administrative expenses	26.2	35.0
Loss on disposition of assets	0.1	5.1
Depreciation and amortization	138.1	128.3
Impairments	—	7.0
Gain on litigation settlement	—	(17.5)
Gross operating margin	$ 380.2	$ 319.6

Table of Contents

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):

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Texas Segment		
Revenues	$ 310.1	$ 324.5
Cost of sales	(161.5)	(179.2)
Total gross operating margin	$ 148.6	$ 145.3
Louisiana Segment		
Revenues	$ 774.1	$ 636.8
Cost of sales	(686.7)	(564.7)
Total gross operating margin	$ 87.4	$ 72.1
Oklahoma Segment		
Revenues	$ 255.1	$ 156.2
Cost of sales	(139.0)	(88.7)
Total gross operating margin	$ 116.1	$ 67.5
Crude and Condensate Segment		
Revenues	$ 650.9	$ 368.6
Cost of sales	(623.3)	(336.7)
Total gross operating margin	$ 27.6	$ 31.9
Corporate Segment		
Revenues	$ (228.5)	$ (164.2)
Cost of sales	229.0	167.0
Total gross operating margin	$ 0.5	$ 2.8
Total		
Revenues	$ 1,761.7	$ 1,321.9
Cost of sales	(1,381.5)	(1,002.3)
Total gross operating margin	$ 380.2	$ 319.6
Midstream Volumes:		
Texas Segment		
Gathering and Transportation (MMBtu/d)	2,190,800	2,274,100
Processing (MMBtu/d)	1,194,100	1,162,100
Louisiana Segment		
Gathering and Transportation (MMBtu/d)	2,222,900	1,931,300
Processing (MMBtu/d)	441,900	467,800
NGL Fractionation (Gals/d)	6,343,500	5,245,500
Oklahoma Segment		
Gathering and Transportation (MMBtu/d)	1,047,900	705,500
Processing (MMBtu/d)	1,069,400	652,800
Crude and Condensate Segment		
Crude Oil Handling (Bbls/d)	127,700	110,400
Brine Disposal (Bbls/d)	2,800	4,300

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017

Gross Operating Margin. Gross operating margin was $380.2 million for the three months ended March 31, 2018 compared to $319.6 million for the three months ended March 31, 2017, an increase of $60.6 million, or 19.0%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $3.3 million, which was primarily due to a $6.4 million increase from our Permian Basin processing assets as a result of higher volumes, partially offset by a $3.1 million decrease from our North Texas assets as a result of lower volumes. The decrease in gross operating margin from our North Texas assets was partially offset by an increase in revenue earned from MVCs (as discussed in more detail below). For the three months ended March 31, 2018, the shortfall revenue from Devon-related MVCs was $18.1 million compared to $12.5 million for the three months ended March 31, 2017.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $15.3 million, which was primarily due to a $20.5 million increase from our NGL transmission and fractionation assets as a result of higher volumes received from our Permian Basin and Oklahoma assets and fees earned from the Ascension JV, which commenced operations in April 2017. This increase was partially offset by a $5.2 million decrease from our gas processing and transmission assets primarily due to the negative impact of seasonal gas price fluctuations, which we manage through our hedging activities. The corresponding realized gain on derivatives was recorded in the Corporate segment.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $48.6 million, which was primarily due to higher volumes as a result of continued producer development in the region.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $4.3 million, which was primarily due to a $3.2 million decrease as a result of condensate stabilization volume declines and transportation rate decreases on our ORV assets. In addition, there was a $1.1 million decrease due to a reduction in our Midland Basin crude business as a result of lower trucked volumes, partially offset by higher volumes on the Greater Chickadee gathering system.

- *Corporate Segment.* Gross operating margin in the Corporate segment decreased $2.3 million, which was due to the changes in fair value of our commodity swaps between the periods. For the three months ended March 31, 2018, realized gains of $4.0 million were partially offset by unrealized losses of $3.5 million. For the three months ended March 31, 2017, realized losses of $2.5 million were offset by unrealized gains of $5.3 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 agree to ship and/or process a minimum volume of commodity on our systems over an agreed time period. If a customer 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 commodity volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer 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.

Revenue recorded for the shortfall between actual production volumes and the MVC is as follows (in millions):

	Texas		Oklahoma		Crude and Condensate		Total	
Three Months Ended								
March 31, 2018								
Midstream services	$	—	$	5.0	$	—	$	5.0
Midstream services—related parties		18.1		1.2		3.4		22.7
Total	$	18.1	$	6.2	$	3.4	$	27.7
March 31, 2017								
Midstream services	$	0.3	$	1.5	$	—	$	1.8
Midstream services—related parties		12.5		3.6		0.8		16.9
Total	$	12.8	$	5.1	$	0.8	$	18.7

On January 1, 2019, certain MVC agreements with Devon for operations in the Texas and Oklahoma segments will expire. These MVC agreements generated $19.3 million in shortfall revenue for the three months ended March 31, 2018.

Operating Expenses. Operating expenses were $109.2 million for the three months ended March 31, 2018 compared to $104.1 million for the three months ended March 31, 2017, an increase of $5.1 million, or 4.9%. The primary contributors to the total increase by segment were as follows (dollars in millions):

	Three Months Ended March 31,				Change			
	2018		2017		$		%	
Texas Segment	$	44.2	$	43.9	$	0.3	0.7	%
Louisiana Segment		25.6		25.4		0.2	0.8	%
Oklahoma Segment		20.7		14.1		6.6	46.8	%
Crude and Condensate Segment		18.7		20.7		(2.0)	(9.7)	%
Total	$	109.2	$	104.1	$	5.1	4.9	%

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $6.6 million primarily due to an increase in labor and benefits expenses due to increased headcount, as well as an increase in materials and supplies, utilities, and ad valorem tax expenses as a result of increased activity on our Oklahoma assets.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $2.0 million primarily due to a decrease in third-party transportation charges.

General and Administrative Expenses. General and administrative expenses were $26.2 million for the three months ended March 31, 2018 compared to $35.0 million for the three months ended March 31, 2017, a decrease of $8.8 million, or 25.1%. The decrease in general and administrative expenses was primarily due to $11.2 million of lower unit-based compensation expense as a result of restricted incentive units being granted for employee bonuses and immediately vesting in the first quarter of 2017, as well as a $1.0 million decrease due to lower professional legal fees paid during the three months ended March 31, 2018. These decreases were partially offset by a $3.8 million increase in bonus expense for the three months ended March 31, 2018.

Depreciation and Amortization. Depreciation and amortization expenses were $138.1 million for the three months ended March 31, 2018 compared to $128.3 million for the three months ended March 31, 2017, an increase of $9.8 million, or 7.6%. Of this increase, $5.5 million was attributable to the expansion of our Central Oklahoma assets, and $2.8 million was attributable to the expansion of our Permian Basin gathering and processing assets.

Impairments. There was no impairment expense for the three months ended March 31, 2018 compared to $7.0 million for the three months ended March 31, 2017. Impairment expense for the three months ended March 31, 2017 related to the carrying values of right-of-ways that we are no longer using and a brine disposal well that was abandoned.

Loss on Disposition of Assets. Loss on disposition of assets was $0.1 million for the three months ended March 31, 2018 compared to a loss of $5.1 million for the three months ended March 31, 2017, an increase of $5.0 million. For the three months ended March 31, 2017, we retired certain plant assets in the Permian Basin that were damaged by fire.

Gain on Litigation Settlement. There was no gain on litigation settlement for the three months ended March 31, 2018 compared to $17.5 million for the three months ended March 31, 2017 related to payments received from a lawsuit settled in 2017.

Interest Expense. Interest expense was $43.7 million for the three months ended March 31, 2018 compared to $44.5 million for the three months ended March 31, 2017, a decrease of $0.8 million, or 1.8%. Interest expense consisted of the following (in millions):

	Three Months Ended March 31,	
	2018	2017
Senior notes	$ 40.0	$ 36.1
Credit facility	3.4	3.4
Capitalized interest	(1.3)	(2.6)
Amortization of debt issue costs and net discounts	1.5	7.3
Other	0.1	0.3
Total	$ 43.7	$ 44.5

Income from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $3.0 million for the three months ended March 31, 2018 compared to income of $0.7 million for the three months ended March 31, 2017, an increase of $2.3 million. The increase was primarily due to a $3.4 million loss for the three months ended March 31, 2017 as a result of the sale of HEP, as well as a $0.6 million increase in income from our investment in GCF during the three months ended March 31, 2018. These increases were partially offset by a $1.7 million decrease in income from our Cedar Cove JV for the three months ended March 31, 2018.

Critical Accounting Policies

Information regarding our critical accounting policies is included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2017, except for our critical accounting policy on revenue recognition, which changed as a result of the adoption of ASC 606 on January 1, 2018. See "Item 1. Financial Statements—Note 2" for information on our revenue recognition accounting policy.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $192.7 million for the three months ended March 31, 2018 compared to $174.2 million for the three months ended March 31, 2017. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Three Months Ended March 31,	
	2018	2017
Operating cash flows before working capital	$ 214.3	$ 173.8
Changes in working capital	(21.6)	0.4

Operating cash flows before changes in working capital increased $40.5 million for the three months ended March 31, 2018 compared to the three months ended March 31, 2017 primarily due to a $62.9 million increase in gross operating margin, excluding gains and losses on derivative activity, and a $6.0 million increase in cash received on derivative settlements, partially offset by a $4.9 million increase in interest expense, excluding amortization of debt issue costs and net discounts, and a $17.5 million gain on litigation settlement for the three months ended March 31, 2017. The remaining difference is due to higher cash paid for operating expenses and general and administrative expenses for the three months ended March 31, 2018. The changes in working capital for the three months ended March 31, 2018 compared to the three months ended March 31, 2017 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 $179.3 million for the three months ended March 31, 2018 and $69.3 million for the three months ended March 31, 2017. Our primary investing cash flows were as follows (in millions):

	Three Months Ended March 31,	
	2018	2017
Growth capital expenditures	$ (175.3)	$ (252.1)
Maintenance capital expenditures	(6.2)	(4.2)
Proceeds from sale of unconsolidated affiliate investment	—	189.7

Growth capital expenditures decreased $76.8 million for the three months ended March 31, 2018 compared to the three months ended March 31, 2017. The decrease was primarily due to completion of capital expenditures related to the Greater Chickadee crude oil gathering system in the Permian Basin and the Ascension JV assets in Louisiana during 2017, and lower capital expenditure levels in 2018 for our expansion projects in the Central Oklahoma assets as compared to 2017.

In addition, we completed the sale of our ownership interest in HEP in March 2017 and received net proceeds of $189.7 million.

Cash Flows from Financing Activities. Net cash used in financing activities was $27.4 million for the three months ended March 31, 2018 and $101.7 million for the three months ended March 31, 2017. Our primary financing activities consisted of the following (in millions):

	Three Months Ended March 31,	
	2018	2017
Net borrowings on credit facility	$ 370.0	$ 210.0
Proceeds from issuance of common units	0.9	55.2
Contributions by non-controlling interests	33.3	40.9
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	(250.0)

For the three months ended March 31, 2018, we sold an aggregate of approximately 0.1 million common units under the 2017 EDA, generating proceeds of $0.9 million. For the three months ended March 31, 2017, we sold an aggregate of approximately 3.0 million common units, generating proceeds of $55.2 million.

For the three months ended March 31, 2018, contributions by non-controlling interests included $10.6 million from ENLC to EnLink Oklahoma T.O and $22.7 million from NGP to the Delaware Basin JV. For the three months ended March 31, 2017, contributions by non-controlling interests included $20.1 million from ENLC to EnLink Oklahoma T.O., $17.1 million from NGP to the Delaware Basin JV, and $3.7 million from Marathon Petroleum to the Ascension JV.

For the three months ended March 31, 2017 and 2018, we made the final two $250.0 million payments under the installment payable obligation related to the EnLink Oklahoma T.O. acquisition.

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

	Three Months Ended March 31,	
	2018	2017
Common units	$ 137.6	$ 134.5
General partner interest (including incentive distribution rights)	15.4	15.1
Distributions to non-controlling interests	10.0	3.3
Distributions to Series B Preferred Units	16.0	—

For the three months ended March 31, 2018, distributions to non-controlling interests included distributions to ENLC for its ownership in EnLink Oklahoma T.O. and distributions to Marathon Petroleum for its ownership in the Ascension JV. For the three months ended March 31, 2017, distributions to non-controlling interests included distributions to ENLC for its ownership in EnLink Oklahoma T.O., distributions to NGP for its ownership in the Delaware Basin JV, and distributions to another minor non-controlling interest.

Series B Preferred Unit distributions for the first quarter of 2017 were paid in-kindin 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 three months ended March 31, 2017. Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions are payable quarterly in cash in 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 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%.

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 remaining 2018 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

		Remainder of 2018
Growth Capital Expenditures		
Texas segment	$	148 - 188
Louisiana segment		59 - 79
Oklahoma segment (1)		243 - 323
Crude and Condensate segment		71 - 81
Corporate segment		4 - 14
Total growth capital expenditures	$	525 - 685
Less: Growth capital expenditures funded by joint venture partners (2)		(83 - 113)
Growth capital expenditures, attributable to the Partnership	$	442 - 572
Maintenance Capital Expenditures	$	49 - 54

(1) Includes projected growth capital contributions related to our non-controlling interest share of the Cedar Cove JV.

(2) Includes growth capital expenditures that will be contributed by other entities and relate to the non-controlling interest share of our consolidated entities. These contributions include contributions by ENLC to EnLink Oklahoma T.O., contributions by NGP to the Delaware Basin JV, and contributions by Marathon Petroleum to the Ascension JV.

Our primary capital projects for the remainder of 2018 include the construction of the Thunderbird processing plant in Central Oklahoma, the Lobo III processing plant in the Delaware Basin, and the development of additional gathering and compression assets in Oklahoma and the Permian Basin. See “Recent Developments” for further details.

We expect to fund growth capital expenditures from the proceeds of borrowings under our credit facility 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 2018, it is possible that not all of the 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. No off-balance sheet arrangements existed as of March 31, 2018.

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

	Payments Due by Period						
	Total	Remainder 2018	2019	2020	2021	2022	Thereafter
Long-term debt obligations (1)	$ 3,500.0	$ —	$ 400.0	$ —	$ —	$ —	$ 3,100.0
Credit facility	370.0	—	—	370.0	—	—	—
Interest payable on fixed long-term debt obligations	2,561.3	147.8	154.5	149.2	149.2	149.2	1,811.4
Capital lease obligations	4.0	1.2	1.5	1.3	—	—	—
Operating lease obligations	106.8	11.1	11.3	8.6	8.6	8.6	58.6
Purchase obligations	33.6	33.6	—	—	—	—	—
Delivery contract obligation	22.4	13.4	9.0	—	—	—	—
Pipeline capacity and deficiency agreements (2)	93.5	14.2	15.0	9.6	9.6	9.6	35.5
Inactive easement commitment (3)	10.0	—	—	—	—	10.0	—
Total contractual obligations	$ 6,701.6	$ 221.3	$ 591.3	$ 538.7	$ 167.4	$ 177.4	$ 5,005.5

(1) On April 1, 2019, $400.0 million in aggregate principal amount of our 2.7% senior unsecured notes will mature.
(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 our credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time.

Our contractual cash obligations for the next twelve months are expected to be funded from cash flows generated from our operations, proceeds from our common unit issuances under the 2017 EDA, asset sales, and borrowings under our credit facility.

Indebtedness

We have a $1.5 billion unsecured revolving credit facility that matures on March 6, 2020, which includes a $500.0 million letter of credit subfacility. As of March 31, 2018, there were $9.8 million in outstanding letters of credit and $370.0 million outstanding borrowings under our credit facility, leaving approximately $1.1 billion available for future borrowing.

In addition, we have $3.5 billion in aggregate principal amount of outstanding unsecured senior notes as of March 31, 2018 with $400.0 million maturing in April 2019 with remaining maturities beginning in 2024 and ending in 2047.

See “Item 1. Financial Statements—Note 5” for more information on our outstanding debt instruments.

Recent Accounting Pronouncements

See “Item 1. Financial Statements—Note 2” for more information on recently issued and adopted accounting pronouncements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q 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 Quarterly 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 Quarterly Report on Form 10-Q, the risk factors set forth in Part II, "Item 1A. Risk Factors" of this report and in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2017 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 3. 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 new relevant regulations that mandate that certain derivatives products be subject to margin requirements, cleared at a clearinghouse, or executed on an exchange. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures, and options. The 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 has withdrawn its appeal of the court order vacating the original position limits rule. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In December 2016, the CFTC modified and reproposed its positions limits rules. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those provisions on us is uncertain at this time.

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

Commodity Price Risk

We are subject to risks due to fluctuations in commodity prices. Approximately 95% of our gross operating margin for the three months ended March 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 three months ended March 31, 2018, approximately 1.4% 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 as 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 three months ended March 31, 2018, approximately 3.2% of our contracts, based on gross operating margin, were 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 and NGLs using OTC derivative financial instruments with only certain well-capitalized counterparties which have been approved by our risk management committee.

We have hedged our exposure to fluctuations in prices for natural gas and NGL 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 March 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 OPIS. 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)
April 2018 - March 2019	Ethane	318 (MBbls)	$0.2640/gal	Index	$ (0.1)
April 2018 - March 2019	Propane	688 (MBbls)	Index	$0.7487/gal	(1.3)
April 2018 - March 2019	Normal Butane	220 (MBbls)	Index	$0.8643/gal	(0.3)
April 2018 - March 2019	Natural Gasoline	88 (MBbls)	Index	$1.2841/gal	(0.6)
April 2018 - October 2019	Natural Gas	71,418 (MMBtu/d)	Index	$2.1009/MMBtu	(2.8)
					$ (5.1)

(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 March 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 liability of $5.1 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $3.6 million in the net fair value of these contracts as of March 31, 2018.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate credit facility. At March 31, 2018, we had $370.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annualized interest expense by approximately $3.7 million for the year.

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 $3,458.1 million as of March 31, 2018, based on market prices of similar debt at March 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 $270.5 million decrease in fair value of our senior unsecured notes at March 31, 2018.

Item 4. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including 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 (March 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 the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required 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 three months ended March 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

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.

Item 1A. Risk Factors

Information about risk factors does not differ materially from that set forth in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 6. 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
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	—	Ninth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of September 21, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 21, 2017, filed with the Commission on September 21, 2017, file No. 001-36340).
3.6	—	Amendment No. 1 to Ninth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of December 12, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 12, 2017, filed with the Commission on December 14, 2017, file No. 001-36340).
3.7	—	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).
3.8	—	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).
3.9	—	Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014, file No. 001-36340).
3.10	—	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
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 Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101 *	—	The following financial information from EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of March 31, 2018 and December 31, 2017, (ii) Consolidated Statements of Operations for the three months ended March 31, 2018 and 2017, (iii) Consolidated Statements of Changes in Partners' Equity for the three months ended March 31, 2018, (iv) Consolidated Statements of Cash Flows for the three months ended March 31, 2018 and 2017, and (v) the Notes to Consolidated Financial Statements.

* Filed herewith.

SIGNATURES

Pursuant to the requirements 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

By: /s/ ERIC D. BATCHELDER
Eric D. Batchelder
Executive Vice President and Chief Financial Officer

May 2, 2018

Exhibit 31.1

CERTIFICATIONS

I, Michael J. Garberding, certify that:

1. I have reviewed this quarterly report on Form 10-Q 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: May 2, 2018

/s/ MICHAEL J. GARBERING

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 quarterly report on Form 10-Q 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: May 2, 2018

/s/ ERIC D. BATCHELDER

Eric D. Batchelder
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 Quarterly Report of EnLink Midstream Partners, LP (the “Registrant”) on Form 10-Q of EnLink Midstream Partners, LP for the quarter ended March 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Michael J. Garberding, Chief Executive Officer of EnLink Midstream GP, LLC, and Eric D. Batchelder, 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: May 2, 2018	/s/ MICHAEL J. GARBERDING
	Michael J. Garberding
	Chief Executive Officer
Date: May 2, 2018	/s/ ERIC D. BATCHELDER
	Eric D. Batchelder
	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.