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 September 30, 2016

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

for the transition period from to

Commission file number: 001-36340

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.)
2501 CEDAR SPRINGS RD. **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 Web site, 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of October 24, 2016, the Registrant had 339,896,417 common units outstanding.

TABLE OF CONTENTS

ENLINK MIDSTREAM PARTNERS, LP
Condensed Consolidated Balance Sheets

	September 30, 2016	December 31, 2015
	(Unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 60.0	$ 5.9
Accounts receivable:		
Trade, net of allowance for bad debt of $0.8 and $0.3, respectively	47.8	37.5
Accrued revenue and other	311.9	268.7
Related party	76.7	111.1
Fair value of derivative assets	4.3	16.8
Natural gas and NGLs inventory, prepaid expenses and other	38.1	32.1
Total current assets	538.8	472.1
Property and equipment, net of accumulated depreciation of $2,036.5 and $1,757.6, respectively	6,195.1	5,666.8
Intangible assets, net of accumulated amortization of $142.0 and $54.6, respectively	1,650.9	689.9
Goodwill	422.3	987.0
Investment in unconsolidated affiliates	266.4	274.3
Other assets, net	2.4	2.7
Total assets	$ 9,075.9	$ 8,092.8
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 44.1	$ 33.2
Accounts payable to related party	11.2	14.8
Accrued gas, NGLs, condensate and crude oil purchases	262.2	206.7
Fair value of derivative liabilities	6.5	2.9
Installment payable, net of discount of $7.4	242.6	—
Other current liabilities	196.2	174.4
Total current liabilities	762.8	432.0
Long-term debt	3,222.8	3,066.8
Fair value of derivative liabilities	—	0.1
Asset retirement obligations	13.4	12.9
Installment payable, net of discount of $32.8	217.2	—
Other long-term liabilities	49.6	65.9
Deferred tax liability	73.2	73.6
Redeemable non-controlling interest	6.2	7.0
Partners' equity:		
Common unitholders (339,531,171 and 325,090,624 units issued and outstanding at September 30, 2016 and December 31, 2015, respectively	3,325.7	4,055.8
Class C unitholders (7,075,433 units issued and outstanding at December 31, 2015)	—	149.4
Preferred unitholders (52,076,035 units issued and outstanding at September 30, 2016)	773.3	—
General partner interest (1,594,974 equivalent units outstanding at September 30, 2016 and December 31, 2015)	209.7	213.4
Non-controlling interest	422.0	15.9
Total partners' equity	4,730.7	4,434.5
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 9,075.9	$ 8,092.8

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Condensed Consolidated Statements of Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(Unaudited) (In millions, except per unit data)			
Revenues:				
Product sales	$ 771.0	$ 863.5	$ 2,097.8	$ 2,488.8
Product sales - affiliates	43.1	40.3	99.3	89.6
Midstream services	125.7	111.3	348.5	351.3
Midstream services - affiliates	165.3	150.3	488.5	449.3
Gain (loss) on derivative activity	(0.5)	5.2	(6.6)	6.6
Total revenues	1,104.6	1,170.6	3,027.5	3,385.6
Operating costs and expenses:				
Cost of sales (1)	788.2	861.8	2,106.8	2,487.4
Operating expenses (2)	98.0	105.0	296.3	312.6
General and administrative (3)	28.3	33.5	90.6	102.3
(Gain) loss on disposition of assets	(3.0)	3.2	(2.9)	3.2
Depreciation and amortization	126.2	98.4	373.0	289.1
Impairments	—	799.2	566.3	799.2
Total operating costs and expenses	1,037.7	1,901.1	3,430.1	3,993.8
Operating income (loss)	66.9	(730.5)	(402.6)	(608.2)
Other income (expense):				
Interest expense, net of interest income	(48.0)	(30.2)	(137.9)	(71.5)
Income (loss) from unconsolidated affiliates	1.1	6.4	(0.5)	16.1
Other income	0.1	0.1	0.1	0.7
Total other expense	(46.8)	(23.7)	(138.3)	(54.7)
Income (loss) before non-controlling interest and income taxes	20.1	(754.2)	(540.9)	(662.9)
Income tax provision	(2.6)	(1.0)	(1.3)	(2.9)
Net income (loss)	17.5	(755.2)	(542.2)	(665.8)
Net loss attributable to the non-controlling interest	(1.3)	(0.3)	(5.6)	(0.3)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 18.8	$ (754.9)	$ (536.6)	$ (665.5)
General partner interest in net income	$ 10.8	$ 6.3	$ 28.8	$ 50.2
Limited partners’ interest in net loss attributable to EnLink Midstream Partners, LP	$ (11.4)	$ (745.2)	$ (602.1)	$ (700.5)
Class C partners’ interest in net loss attributable to EnLink Midstream Partners, LP	$ —	$ (16.0)	$ (12.5)	$ (15.2)
Preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 19.4	$ —	$ 49.2	$ —
Net loss attributable to EnLink Midstream Partners, LP per limited partners’ unit:				
Basic common unit	$ (0.03)	$ (2.32)	$ (1.82)	$ (2.38)
Diluted common unit	$ (0.03)	$ (2.32)	$ (1.82)	$ (2.38)

(1) Includes affiliate cost of sales of $33.7 million and $51.9 million for the three months ended September 30, 2016 and 2015, respectively, and $126.0 million and $91.7 million for the nine months ended September 30, 2016 and 2015, respectively.
(2) Includes affiliate operating expenses of $0.1 million and $0.1 million for the three months ended September 30, 2016 and 2015, respectively, and $0.4 million and $0.3 million for the nine months ended September 30, 2016 and 2015, respectively.
(3) Includes affiliate general and administrative expenses of $0.1 and $0.2 million for the three and nine months ended September 30, 2015, respectively.

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statement of Changes in Partners' Equity
Nine Months Ended September 30, 2016

	Common Units		Class C Common Units		Preferred Units		General Partner Interest		Non-Controlling Interest		Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	Total	$
						(Unaudited) (In millions)					
Balance, December 31, 2015	$ 4,055.8	325.2	$ 149.4	7.1	$ —	—	$ 213.4	1.6	$ 15.9	$ 4,434.5	$ 7.0
Issuance of common units	110.6	6.7	—	—	—	—	—	—	—	110.6	—
Issuance of Preferred Units	—	—	—	—	724.1	50.0	—	—	—	724.1	—
Contribution from ENLC	—	—	—	—	—	—	—	—	237.1	237.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(1.2)	0.2	—	—	—	—	—	—	—	(1.2)	—
Unit-based compensation	11.3	—	—	—	—	—	11.2	—	—	22.5	—
Contribution from Devon	1.4	—	—	—	—	—	—	—	—	1.4	—
Distributions	(387.0)	—	—	0.4	—	2.1	(43.7)	—	—	(430.7)	—
Conversion of Class C Common Units to common units	136.9	7.5	(136.9)	(7.5)	—	—	—	—	—	—	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	179.4	179.4	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	(4.8)	(4.8)	—
Distributions to redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	(0.8)
Net income (loss)	(602.1)	—	(12.5)	—	49.2	—	28.8	—	(5.6)	(542.2)	—
Balance, September 30, 2016	$ 3,325.7	339.6	$ —	—	$ 773.3	52.1	$ 209.7	1.6	$ 422.0	$ 4,730.7	$ 6.2

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Cash Flows

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net loss	$ (542.2)	$ (665.8)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Impairments	566.3	799.2
Depreciation and amortization	373.0	289.1
Accretion expense	0.4	0.4
(Gain) loss on disposition of assets	(2.9)	3.2
Non-cash unit-based compensation	22.5	28.6
Deferred tax benefit	(0.3)	—
(Gain) loss on derivatives recognized in net income (loss)	6.6	(6.6)
Cash settlements on derivatives	9.5	13.0
Amortization of debt issue costs	2.6	2.2
Amortization of net (premium) discount on notes	36.9	(2.2)
Redeemable non-controlling interest expense	0.3	(2.0)
Distribution of earnings from unconsolidated affiliates	0.7	17.1
(Income) loss from unconsolidated affiliates	0.5	(16.1)
Changes in assets and liabilities net of assets acquired and liabilities assumed:		
Accounts receivable, accrued revenue and other	(17.6)	124.3
Natural gas and NGLs inventory, prepaid expenses and other	3.6	(18.4)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	49.3	(58.0)
Net cash provided by operating activities	509.2	508.0
Cash flows from investing activities, net of assets acquired and liabilities assumed:		
Additions to property and equipment	(423.7)	(450.3)
Proceeds from insurance settlement	0.3	—
Acquisition of business, net of cash acquired	(769.3)	(330.6)
Proceeds from sale of property	4.7	0.4
Investment in unconsolidated affiliates	(45.0)	(8.1)
Distribution from unconsolidated affiliates in excess of earnings	51.6	14.3
Net cash used in investing activities	(1,181.4)	(774.3)
Cash flows from financing activities:		
Proceeds from borrowings	1,629.3	2,604.4
Payments on borrowings	(1,469.2)	(1,773.2)
Payments on capital lease obligations	(3.2)	(2.5)
Decrease in drafts payable	—	(12.6)
Debt financing costs	(4.6)	(9.5)
Conversion of restricted units, net of units withheld for taxes	(1.2)	(2.5)
Proceeds from issuance of common units	110.6	12.9
Proceeds from issuance of Preferred Units	724.1	—
Distributions to non-controlling partners	(5.6)	(66.5)
Contributions by non-controlling partners (including contributions from affiliates of $27.9 million)	179.4	12.2
Distribution to partners	(430.7)	(338.9)
Mandatorily redeemable non-controlling interest	(4.0)	—
Contribution from Devon	1.4	28.8
Distributions to Devon for net assets acquired	—	(171.0)
Net cash provided by financing activities	726.3	281.6
Net increase in cash and cash equivalents	54.1	15.3
Cash and cash equivalents, beginning of period	5.9	9.6
Cash and cash equivalents, end of period	$ 60.0	$ 24.9
Cash paid for interest	$ 70.4	$ 45.5
Cash paid for income taxes	$ 2.5	$ 0.4

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Condensed Consolidated Financial Statements
September 30, 2016
(Unaudited)

(1) General

In this report, the term "Partnership," as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership (as defined below) and EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O."). EnLink Oklahoma T.O. is sometimes used to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP together with its consolidated subsidiaries.

(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, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is an indirect wholly-owned subsidiary of EnLink Midstream, LLC ("ENLC"). ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." Devon Energy Corporation ("Devon") owns ENLC's managing member and common units which represent approximately 64% of the outstanding limited liability company interests in ENLC.

Effective as of January 7, 2016, the Operating Partnership acquired 84% of the outstanding equity interests in EnLink Oklahoma T.O., and ENLC acquired the remaining 16% equity interests in EnLink Oklahoma T.O. Since we control EnLink Oklahoma T.O., we reflect our ownership in EnLink Oklahoma T.O. on a consolidated basis and ENLC's ownership is reflected as a non-controlling interest in the respective condensed consolidated financial statements and related disclosures.

On August 1, 2016, we formed a joint venture (the "Delaware Basin JV") with an affiliate of NGP Natural Resources XI, L.P. ("NGP") to operate and expand our natural gas, natural gas liquids ("NGLs") and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1 percent by us and 49.9 percent by NGP. Since we control the Delaware Basin JV, we reflect our ownership in the Delaware Basin JV on a consolidated basis, and NGP's ownership is reflected as a non-controlling interest in the respective condensed consolidated financial statements and related disclosures.

(b) Nature of Business

We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing to producers of natural gas, natural gas liquids, crude oil and condensate. We connect the wells of producers in our market areas to our gathering systems, process natural gas to remove NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee-based arrangements. We provide a variety of crude oil and condensate services, which include crude oil and condensate gathering and transmission via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. We also have crude oil and condensate terminal facilities that provide access for crude oil and condensate producers to premium markets. Our gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. We also have transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants to our fractionators in south Louisiana. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport crude oil from a producer site to an end user. Our processing plants remove NGLs and CO_2 from a natural gas stream, and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

(2) Significant Accounting Policies

(a) *Basis of Presentation*

The accompanying condensed 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 generally accepted accounting principles in the United States of America ("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.

During the first half of 2015, we acquired assets from ENLC and Devon through drop down transactions. Due to ENLC's control of us through its ownership and control of our general partner and Devon's control of us through its ownership of the managing member of ENLC, each acquisition from ENLC and Devon was considered a transfer of net assets between entities under common control. As such, we were required to recast our historical financial statements to include the activities of such assets from the date that these entities were under common control. The condensed consolidated financial statements for periods prior to our acquisition of the assets from ENLC and Devon have been prepared from ENLC's and Devon's historical cost-basis accounts for the acquired assets and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the acquired assets during the periods reported. Net income attributable to the assets acquired from ENLC and Devon for periods prior to our acquisition is allocated to our general partner.

(b) Adopted Accounting Standards

In January 2016, we adopted Accounting Standards Update ("ASU") 2015-03, *Interest - Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs*. The update requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability and requires retrospective application. The application of this new accounting guidance resulted in the reclassification of $23.0 million of debt issuance costs from "Other Assets, Net" to "Long-term debt" in our accompanying Condensed Consolidated Balance Sheet as of December 31, 2015.

In January 2016, we adopted ASU 2015-17, *Balance Sheet Classification of Deferred Taxes* on a prospective basis. This new standard required that deferred tax assets and liabilities be classified as noncurrent in our Condensed Consolidated Balance Sheet.

In January 2016, we adopted ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*, which eliminates the requirement for an acquirer to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated.

In January 2016, we adopted ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The update provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporations and securitization structures, should be consolidated. The update is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. This update had no impact on our condensed consolidated financial statements or related disclosures.

In January 2016, we adopted ASU 2015-06, *Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions (a Consensus of the FASB Emerging Issues Task Force)* ("ASU 2015-06"), which requires a master limited partnership (MLP) to allocate earnings (losses) of a transferred business entirely to the general partner when computing earnings per unit (EPU) for periods before the dropdown transaction occurred. The EPU that the limited partners previously reported would not change as a result of the dropdown transaction. ASU 2015-06 also requires an MLP to disclose the effects of the dropdown transaction on EPU for the periods before and after the dropdown transaction occurred. ASU 2015-06 is effective for the fiscal years beginning after December 15, 2015, and interim periods within those annual periods. ASU 2015-06 requires retrospective application and early adoption is permitted. The update is effective for us beginning on January 1, 2016 and had no impact on our condensed consolidated financial statements or related disclosures.

In August 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-15,*Statement of Cash Flows (Topic 230) – Classification of Certain Cash Receipts and Cash Payments* ("ASU 2016-15"). ASU 2016-15 addresses the classification and presentation of certain cash receipts and cash payments related to debt prepayment or debt extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, and other specific cash flow issues. ASU 2016-15 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and should be applied using a retrospective transition method to each period presented. Early application is permitted, including adoption in an interim period. In September 2016, we elected to early adopt ASU 2016-15 effective January 1, 2016. The adoption had no impact on our condensed consolidated financial statements or related disclosures.

(c) Accounting Standards to be Adopted in Future Periods

In March 2016, the FASB issued ASU 2016-09,*Improvements to Employee Share-Based Payment Accounting*, which amends Accounting Standards Codification ("ASC") Topic 718, Compensation – Stock Compensation ("ASU 2016-09"). First, the new standard will require all of the tax effects related to share-based payments at settlement (or expiration) to be recorded through the income statement, and is required to be applied prospectively. Second, the new standard also allows entities to withhold taxes of an amount up to the employees' maximum individual tax rate in the relevant jurisdiction without resulting in liability classification of the award, and is required to be adopted using a modified retrospective approach. Third, under the ASU, forfeitures can be estimated, as currently required, or recognized when they occur. If elected, the change to recognize forfeitures when they occur must be adopted using a modified retrospective approach. ASU 2016-09 is effective for annual reporting periods beginning after December 15, 2016 including interim periods within those annual periods. Early adoption is permitted. We do not expect this standard to materially impact our condensed consolidated financial statements or related disclosures.

In February 2016, the FASB issued ASU 2016-02,*Leases (Topic 842) - Amendments to the FASB Accounting Standards Codification* ("ASU 2016-02"). 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. ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018 including interim periods within those annual periods. Early adoption is permitted, and is required to be adopted using a modified retrospective transition. We are currently evaluating the impact this standard will have on our condensed consolidated financial statements and related disclosures.

In May 2014, the FASB issued ASU 2014-09,*Revenue from Contracts with Customers* ("ASU 2014-09"). ASU 2014-09 will replace existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which we expect to be entitled in exchange for transferring goods or services to a customer. The new standard will also require significantly expanded disclosures regarding the qualitative and quantitative information of our nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied retrospectively, with early application permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact the pronouncements will have on our condensed consolidated financial statements and related disclosures.

(3) Acquisitions

Matador Acquisition

On October 1, 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing assets operations in the Delaware Basin, for approximately $141.3 million. The transaction was accounted for using the acquisition method.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date.

Purchase Price Allocation (in millions):

Assets acquired:	
Current assets	$ 1.1
Property, plant and equipment	35.5
Intangibles	98.8
Goodwill	10.7
Liabilities assumed:	
Current liabilities	(4.8)
Total identifiable net assets	$ 141.3

We recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer life of approximately 15 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Permian Basin. All such goodwill is allocated to our Texas segment and is non-deductible for tax purposes.

Deadwood Acquisition

Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). On November 16, 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million, all of which is considered property, plant and equipment. The final working capital settlement paid to Apache was approximately $1.5 million. The transaction was accounted for using the acquisition method.

Tall Oak Acquisition

On January 7, 2016, we and ENLC acquired an 84% and 16% voting interest, respectively, in EnLink Oklahoma T.O. for approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The final installment of $500.0 million is due by us no later than the first anniversary of the closing date with the option to defer $250.0 million of the final installment up to 24 months following the closing date. The installment payables are valued net of discount within the total purchase price.

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

The following table presents the consideration we paid and the fair value of the identified assets received and liabilities assumed at the acquisition date. The purchase price allocation has been prepared on a preliminary basis pending receipt of a final valuation report and is subject to change.

Consideration (in millions):	
Cash	$ 783.6
Total installment payable, net of discount of $79.1 million assuming payments are made on January 7, 2017 and 2018	420.9
Contribution from ENLC	237.1
Total consideration	$ 1,441.6
Purchase Price Allocation (in millions):	
Assets acquired:	
Current assets (including $12.8 million in cash)	$ 23.0
Property, plant and equipment	408.5
Intangibles	1,048.4
Liabilities assumed:	
Current liabilities	(38.3)
Total identifiable net assets	$ 1,441.6

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

We incurred $3.7 million of direct transaction costs for the nine months ended September 30, 2016. These costs are included in general and administrative costs in the accompanying Condensed Consolidated Statements of Operations.

For the period from January 7, 2016 to September 30, 2016, we recognized $149.5 million of revenues and $27.9 million of net loss related to the assets acquired.

Pro Forma Information

The following unaudited pro forma condensed financial information for the three and nine months ended September 30, 2015 gives effect to the January 2015 LPC acquisition, March 2015 Coronado acquisition, October 2015 Matador acquisition, November 2015 Deadwood acquisition and January 2016 Tall Oak acquisition as if they had occurred on January 1, 2015. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
	(in millions)	
Pro forma total revenues	$ 1,205.9	$ 3,556.7
Pro forma net loss	$ (775.9)	$ (727.8)
Pro forma net loss attributable to EnLink Midstream Partners, LP	$ (772.7)	$ (718.1)
Pro forma net loss per common unit:		
Basic	$ (2.34)	$ (2.49)
Diluted	$ (2.34)	$ (2.49)

(4) Goodwill and Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value of goodwill to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. During February 2016, we determined that continued further weakness in the overall energy sector driven by low commodity prices together with a further decline in our unit price subsequent to year-end caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors.

The fair value of goodwill is based on inputs that are not observable in the market and thus represent Level 3 inputs. Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair values of our Texas and Crude and Condensate reporting units were less than their respective carrying amounts, primarily related to increases in our discount rate subsequent to year-end. The second step of the goodwill impairment test measures the amount of impairment loss and involves allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit as if the reporting unit had been acquired in a business combination. Through the analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized for the three months ended March 31, 2016, which is included in our nine months ended September 30, 2016 impairments line item in the Condensed Consolidated Statements of Operations.

We concluded that the fair value of goodwill of our Oklahoma reporting unit exceeded its carrying value, and the entire amount of goodwill disclosed on the Condensed Consolidated Balance Sheet associated with this remaining reporting unit is recoverable. Therefore, no other goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analysis.

Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to additional goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. The estimated fair value of our Texas reporting unit may be impacted in the future by a further decline in our unit price or a continuing prolonged period of lower commodity prices which may adversely affect our estimate of future cash flows, both of which could result in future goodwill impairment charges for our Texas reporting unit.

The table below provides a summary of our change in carrying amount of goodwill, by assigned reporting unit (in millions):

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
	(in millions)					
Nine Months Ended September 30, 2016						
Balance, beginning of period	$ 703.5	$ —	$ 190.3	$ 93.2	$ —	$ 987.0
Impairment	(473.1)	—	—	(93.2)	—	(566.3)
Acquisition adjustment	1.6	—	—	—	—	1.6
Balance, end of period	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3

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 ten to twenty years.

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Nine Months Ended September 30, 2016			
Customer relationships, beginning of period	$ 744.5	$ (54.6)	$ 689.9
Acquisitions	1,048.4	—	1,048.4
Amortization expense	—	(87.4)	(87.4)
Customer relationships, end of period	$ 1,792.9	$ (142.0)	$ 1,650.9

The weighted average amortization period for intangible assets is 13.7 years. Amortization expense for intangibles was approximately $29.9 million and $14.6 million for the three months ended September 30, 2016 and 2015, respectively, and $87.4 million and $44.3 million for the nine months ended September 30, 2016 and 2015, respectively.

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

2016 remaining	$ 29.4
2017	117.7
2018	117.7
2019	117.7
2020	117.7
Thereafter	1,150.7
Total	$ 1,650.9

(5) Affiliate Transactions

We engage in various transactions with Devon and other affiliated entities. For the three and nine months ended September 30, 2016 and 2015, Devon was a significant customer to us. Devon accounted for 18.9% and 19.4% of our revenues for the three and nine months ended September 30, 2016, respectively, and 16.3% and 15.9% for the three and nine months ended September 30, 2015, respectively. We had an accounts receivable balance related to transactions with Devon of $76.7 million as of September 30, 2016 and $110.8 million as of December 31, 2015. Additionally, we had an accounts payable balance related to transactions with Devon of $11.2 million as of September 30, 2016 and $14.8 million as of December 31, 2015. Management believes these transactions are executed on terms that are fair and reasonable and are consistent with terms for transactions with nonaffiliated third parties. The amounts related to affiliate transactions are specified in the accompanying financial statements.

EnLink Oklahoma T.O. Gathering and Processing Agreement with Devon

In January 2016, in connection with the Tall Oak acquisition, we acquired a Gas Gathering and Processing Agreement with Devon Energy Production Company, L.P. ("DEPC") pursuant to which EnLink Oklahoma T.O. provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by DEPC. The agreement has a minimum volume commitment that will remain in place during each calendar quarter for the next five years and a remaining overall term of approximately 13 years. Additionally, the agreement provides EnLink Oklahoma T.O. with dedication of all of the natural gas owned or controlled by DEPC and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by DEPC. DEPC is entitled to firm service, meaning a level of gathering and processing service in which DEPC's reserved capacity may not be interrupted, except due to force majeure, and may not be displaced by another customer or class of service.

(6) Long-Term Debt

As of September 30, 2016 and December 31, 2015, long-term debt consisted of the following (in millions):

	September 30, 2016			December 31, 2015		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Partnership credit facility, due 2020 (1)	$ 75.0	$ —	$ 75.0	$ 414.0	$ —	$ 414.0
2.70% Senior unsecured notes due 2019	400.0	(0.3)	399.7	400.0	(0.4)	399.6
7.125% Senior unsecured notes due 2022	162.5	16.7	179.2	162.5	18.9	181.4
4.40% Senior unsecured notes due 2024	550.0	2.6	552.6	550.0	2.9	552.9
4.15% Senior unsecured notes due 2025	750.0	(1.1)	748.9	750.0	(1.2)	748.8
4.85% Senior unsecured notes due 2026	500.0	(0.7)	499.3	—	—	—
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	(6.7)	443.3	450.0	(6.9)	443.1
Other debt	—	—	—	0.2	—	0.2
Debt classified as long-term	$ 3,237.5	$ 10.3	$ 3,247.8	$ 3,076.7	$ 13.1	$ 3,089.8
Debt issuance cost (2)			(25.0)			(23.0)
Long-term debt, net of unamortized issuance cost			$ 3,222.8			$ 3,066.8

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 2.2% at September 30, 2016 and 1.8% at December 31, 2015.
(2) Net of amortization of $7.3 million and $4.7 million at September 30, 2016 and December 31, 2015, respectively.

Credit Facility

We have a $1.5 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility that matures on March 6, 2020. 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, on two 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 or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent's prime rate) plus an applicable margin. The applicable margins vary depending on our credit rating. If we breach certain covenants governing our credit facility, amounts outstanding under our credit facility, if any, may become due and payable immediately.

As of September 30, 2016, there were $11.0 million in outstanding letters of credit and $75.0 million in outstanding borrowings under our credit facility, leaving approximately $1.4 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

All other material terms and conditions of our credit facility are described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in our Annual Report on Form 10-K for the year ended December 31, 2015. We expect to be in compliance with all credit facility covenants for at least the next twelve months.

Senior Unsecured Notes due 2026

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year, beginning January 15, 2017. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our revolving credit facility and for general partnership purposes.

(7) Partners' Capital

(a) Issuance of Common Units

In November 2014, we entered into an Equity Distribution Agreement (the "BMO EDA") with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the "Sales Agents") to sell up to $350.0 million in aggregate gross sales of 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 BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. For the nine months ended September 30, 2016, we sold an aggregate of 6.7 million common units under the BMO EDA, generating proceeds of approximately $110.6 million (net of approximately $1.1 million of commissions). We used the net proceeds for general partnership purposes. As of September 30, 2016, approximately $205.3 million remains available to be issued under the BMO EDA.

(b) Class C Common Units

In March 2015, we issued 6,704,285 Class C Common Units representing a new class of limited partner interests as partial consideration for the acquisition of Coronado. The Class C Common Units were substantially similar in all respects to our common units, except that distributions paid on the Class C Common Units could be paid in cash or in additional Class C Common Units issued in kind, as determined by our general partner in its sole discretion. Distributions on the Class C Common Units for the three months ended December 31, 2015 and March 31, 2016 were paid-in-kind through the issuance of 209,044 and 233,107 Class C Common Units on February 11, 2016 and May 12, 2016, respectively. All of the outstanding Class C Common Units were converted into common units on a one-for-one basis on May 13, 2016.

(c) Preferred Units

In January 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units (the "Preferred Units") representing our limited partner interests to Enfield Holdings, L.P. ("Enfield") in a private placement for a cash purchase price of $15.00 per Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the Tall Oak acquisition. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield. The Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, at any time after the record date for the quarter ending June 30, 2017 (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Preferred Units would then convert and (ii) the number of Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

As a holder of Preferred Units, Enfield is entitled to receive a quarterly distribution, subject to certain adjustments, equal to (x) during the quarter ending March 31, 2016 through the quarter ending June 30, 2017, an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Preferred Units and (y) thereafter, an annual rate of 7.5% on the Issue Price payable in cash (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) an annual rate of 1.0% of the Issue Price and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price. Distributions on the Preferred Units for the three months ended March 31, 2016 and June 30, 2016, were paid-in kind through the issuance of 992,445 and 1,083,589 Preferred Units on May 12, 2016 and August 11, 2016, respectively. A distribution on the Preferred Units was declared for the three months ended September 30, 2016, which will result in the issuance of 1,106,616 additional Preferred Units on November 10, 2016. Income was allocated to the Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. For the three and nine months ended September 30, 2016, $19.4 million and $49.2 million of income was allocated to the Preferred Units, respectively.

(d) 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 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. Our general partner is not entitled to its general partner or incentive distributions with respect to the Preferred Units issued in kind.

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

A summary of the distribution activity relating to the common units for the nine months ended September 30, 2016 is provided below:

Declaration period	Distribution/unit		Date paid/payable
Fourth Quarter of 2015	$	0.39	February 11, 2016
First Quarter of 2016	$	0.39	May 12, 2016
Second Quarter of 2016	$	0.39	August 11, 2016
Third Quarter of 2016	$	0.39	November 11, 2016

(e) Earnings per Unit and Dilution Computations

As required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. Net income (loss) attributable to drop down interests acquired during 2015 from ENLC and Devon for periods prior to acquisition is not allocated to the limited partners for purposes of calculating net income (loss) per common unit. The following table reflects the computation of basic and diluted earnings per limited partner unit for the period presented (in millions, except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Limited partners' interest in net income (loss)	$ (11.4)	$ (745.2)	$ (602.1)	$ (700.5)
Distributed earnings allocated to:				
Common units (1) (2)	$ 131.5	$ 125.2	$ 387.0	$ 339.5
Unvested restricted units (1) (2)	0.9	0.5	2.6	1.5
Total distributed earnings	$ 132.4	$ 125.7	$ 389.6	$ 341.0
Undistributed loss allocated to:				
Common units	$ (142.8)	$ (867.6)	$ (985.1)	$ (1,037.1)
Unvested restricted units	(1.0)	(3.3)	(6.6)	(4.4)
Total undistributed loss	$ (143.8)	$ (870.9)	$ (991.7)	$ (1,041.5)
Net income (loss) allocated to:				
Common units	$ (11.3)	$ (742.4)	$ (598.1)	$ (697.6)
Unvested restricted units	(0.1)	(2.8)	(4.0)	(2.9)
Total limited partners' interest in net income (loss)	$ (11.4)	$ (745.2)	$ (602.1)	$ (700.5)
Basic and diluted net income (loss) per unit:				
Basic	$ (0.03)	$ (2.32)	$ (1.82)	$ (2.38)
Diluted	$ (0.03)	$ (2.32)	$ (1.82)	$ (2.38)

(1) Three months ended September 30, 2016 and 2015 represents a declared distribution of $0.39 per unit payable on November 11, 2016 and a distribution of $0.39 per unit paid on November 12, 2015, respectively.

(2) Represents a declared distribution of $0.39 per unit payable on November 11, 2016, and distributions paid of $0.39 per unit on August 11, 2016, $0.39 per unit on May 12, 2016, $0.39 per unit on November 12, 2015, $0.385 per unit on August 13, 2015, and $0.38 per unit on May 14, 2015 for the nine months ended September 30, 2016 and 2015.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Basic weighted average units outstanding:				
Weighted average limited partner basic common units outstanding (1)	337.2	327.9	330.8	298.9
Diluted weighted average units outstanding:				
Weighted average limited partner basic common units outstanding	337.2	327.9	330.8	298.9
Dilutive effect of restricted units issued	—	—	—	—
Total weighted average limited partner diluted common units outstanding	337.2	327.9	330.8	298.9

(1) The nine months ended September 30, 2016 includes the weighted average impact of 3,645,688 Common Class C Common Units that converted into common units on May 13, 2016. The three and nine months ended September 30, 2015 includes the weighted average impact of 6,867,012 and 4,939,219 Common Class C Common Units, respectively, that converted into common units on May 13, 2016 and 13,537,133 and 9,258,104 Common Class E Common Units, respectively, that converted into common units on August 3, 2015.

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. All common unit equivalents were antidilutive for the three and nine months ended September 30, 2016 and 2015 because the limited partners were allocated a net loss.

Net income is allocated to our general partner in an amount equal to its incentive distributions as described in (d) above. Our general partner's share of net income consists of incentive distributions 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 to our general partner. The net income allocated to our general partner is as follows for the periods presented (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Income allocation for incentive distributions	$ 14.4	$ 13.6	$ 42.4	$ 33.7
Unit-based compensation attributable to ENLC's restricted units	(3.6)	(3.7)	(11.2)	(14.6)
General partner share of net income (loss)	—	(3.6)	(2.4)	(3.3)
General partner interest in drop down transactions	—	—	—	34.4
General partner interest in net income	$ 10.8	$ 6.3	$ 28.8	$ 50.2

(8) Asset Retirement Obligations

The schedule below summarizes the changes in our liabilities for asset retirement obligations:

	Nine Months Ended September 30,	
	2016	2015
	(in millions)	
Beginning asset retirement obligations	$ 14.0	$ 20.6
Revisions to the fair values of existing liabilities	(0.4)	(4.0)
Accretion expense	0.4	0.4
Liabilities settled	(0.6)	(3.2)
Ending asset retirement obligations	$ 13.4	$ 13.8

Asset retirement obligations of $13.4 million and $12.9 million were included in "Asset retirement obligations" as noncurrent liabilities on the Condensed Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015, respectively. Asset retirement obligations of $1.1 million were included in "Other current liabilities" on the Condensed Consolidated Balance Sheets as of December 31, 2015. There were no asset retirement obligations included in "Other current liabilities" on the Condensed Consolidated Balance Sheet as of September 30, 2016.

(9) Investment in Unconsolidated Affiliates

Our unconsolidated investments consisted of a contractual right to the economic benefits and burdens associated with Devon's 38.75% ownership interest in Gulf Coast Fractionators ("GCF") at September 30, 2016 and 2015 and approximately 31.0% common unit ownership interest in Howard Energy Partners ("HEP") at September 30, 2016 and 2015.

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

	Gulf Coast Fractionators	Howard Energy Partners	Total
Three Months Ended			
September 30, 2016			
Contributions (1)	$ —	$ 3.2	$ 3.2
Distributions (2)	$ 0.9	$ 36.5	$ 37.4
Equity in income	$ 2.2	$ (1.1)	$ 1.1
September 30, 2015			
Contributions	$ —	$ 8.1	$ 8.1
Distributions	$ 3.8	$ 8.4	$ 12.2
Equity in income	$ 3.4	$ 3.0	$ 6.4
Nine Months Ended			
September 30, 2016			
Contributions (1)	$ —	$ 45.0	$ 45.0
Distributions (2)	$ 4.4	$ 47.9	$ 52.3
Equity in income	$ 1.1	$ (1.6)	$ (0.5)
September 30, 2015			
Contributions	$ —	$ 8.1	$ 8.1
Distributions	$ 10.7	$ 20.7	$ 31.4
Equity in income	$ 9.7	$ 6.4	$ 16.1

(1) Contributions for the three and nine months ended September 30, 2016 include $3.2 and $32.7 million, respectively, of contributions to HEP for preferred units, which were redeemed during the third quarter 2016.

(2) Distributions for the three and nine months ended September 30, 2016 include a redemption of $32.7 million of preferred units.

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

	September 30, 2016	December 31, 2015
Gulf Coast Fractionators	$ 49.2	$ 52.6
Howard Energy Partners	217.2	221.7
Total investment in unconsolidated affiliates	$ 266.4	$ 274.3

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

We account for unit-based compensation in accordance with FASB ASC 718, which requires that compensation related to all unit-based awards, including unit options, be recognized in the condensed consolidated financial statements. On April 7, 2016, our general partner amended and restated the EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”). Amendments to the GP Plan included an increase to the number of common units of the Partnership authorized for issuance under the GP Plan by 5,000,000 common units to an aggregate of 14,070,000 common units and other technical changes.

We and ENLC each have similar unit-based compensation payment plans for officers and employees, which are described below. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to our 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 in the condensed consolidated financial statements with respect to these plans are as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Cost of unit-based compensation charged to general and administrative expense	$ 5.7	$ 6.3	$ 17.5	$ 24.6
Cost of unit-based compensation charged to operating expense	1.6	1.0	5.0	4.0
Total amount charged to income	$ 7.3	$ 7.3	$ 22.5	$ 28.6

(b) EnLink Midstream Partners, LP Restricted Incentive Units

Our restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of common units on such date. A summary of the restricted incentive unit activity for the nine months ended September 30, 2016 is provided below:

	Nine Months Ended September 30, 2016	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,253,729	$ 29.59
Granted	1,058,732	10.12
Vested*	(315,686)	30.07
Forfeited	(57,601)	21.27
Non-vested, end of period	1,939,174	$ 19.13
Aggregate intrinsic value, end of period (in millions)	$ 34.3	

* Vested units include 90,847 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 during the three and nine months ended September 30, 2016 and 2015, respectively, is provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream Partners, LP Restricted Incentive Units:	2016	2015	2016	2015
Aggregate intrinsic value of units vested	$ 0.3	$ 0.1	$ 4.1	$ 7.2
Fair value of units vested	$ 0.5	$ 0.1	$ 9.5	$ 7.6

As of September 30, 2016, there was $15.8 million of unrecognized compensation cost related to non-vested restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.6 years.

(c) EnLink Midstream Partners, LP Performance Units

In 2016, our general partner and the managing member of ENLC granted performance awards under the GP Plan and the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "LLC Plan"), respectively. The performance award agreements provide that the vesting of 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 Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding us and ENLC (collectively, "EnLink"), on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of the Partnership'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 range from zero to 200 percent 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 group securities; (iii) an estimated ranking of us among the designated peer group; and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of three years. The following table presents a summary of the grant-date fair values of performance units granted and the related assumptions:

EnLink Midstream Partners, LP Performance Units:	January 2016	February 2016
Beginning TSR Price	$ 14.82	$ 14.82
Risk-free interest rate	1.10 %	0.89 %
Volatility factor	39.71 %	42.33 %
Distribution yield	12.10 %	19.20 %

The following table presents a summary of our performance units:

	Nine Months Ended September 30, 2016	
EnLink Midstream Partners, LP Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	118,126	$ 35.41
Granted	258,078	9.81
Forfeited	(2,798)	36.18
Non-vested, end of period	373,406	$ 17.71
Aggregate intrinsic value, end of period (in millions)	$ 6.6	

As of September 30, 2016, there was $3.8 million of unrecognized compensation expense that related to our non-vested performance units. That cost is expected to be recognized over a weighted-average period of 1.8 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 the common units on such date. A summary of the restricted incentive unit activity for the nine months ended September 30, 2016 is provided below:

	Nine Months Ended September 30, 2016	
EnLink Midstream, LLC Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,148,893	$ 34.78
Granted	1,051,410	9.53
Vested*	(339,399)	36.55
Forfeited	(53,872)	22.74
Non-vested, end of period	1,807,032	$ 20.11
Aggregate intrinsic value, end of period (in millions)	$ 30.3	

* Vested units include 96,864 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 during the three and nine months ended September 30, 2016 and 2015, respectively, are provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream, LLC Restricted Incentive Units:	**2016**	**2015**	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 0.3	$ 0.1	$ 4.1	$ 8.9
Fair value of units vested	$ 0.6	$ 0.1	$ 12.4	$ 9.3

As of September 30, 2016, there was $15.4 million of unrecognized compensation costs related to non-vested ENLC restricted incentive units. The cost is expected to be recognized over a weighted-average period of 1.6 years.

(e) EnLink Midstream, LLC's Performance Units

In 2016, ENLC granted performance awards under the LLC Plan discussed in Note (c) above. 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 range from zero to 200 percent 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 group securities; (iii) an estimated ranking of ENLC among the designated peer group and (iv) the distribution yield. The fair value of the unit on the date of grant is expensed over a vesting period of three years. The following table presents a summary of the grant-date fair values of performance units granted and the related assumptions:

EnLink Midstream, LLC Performance Units:	**January 2016**	**February 2016**
Beginning TSR Price	$ 15.38	$ 15.38
Risk-free interest rate	1.10 %	0.89 %
Volatility factor	46.02 %	52.05 %
Distribution yield	8.60 %	14.00 %

The following table presents a summary of ENLC's performance units:

	Nine Months Ended September 30, 2016	
EnLink Midstream, LLC Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	105,080	$ 40.50
Granted	242,646	9.59
Forfeited	(2,525)	41.31
Non-vested, end of period	345,201	$ 18.76
Aggregate intrinsic value, end of period (in millions)	$ 5.8	

As of September 30, 2016, there was $3.7 million of unrecognized compensation expense that related to non-vested ENLC performance units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(11) Derivatives

Commodity Swaps

We manage our exposure to fluctuation in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs. We do not designate transactions as cash flow or fair value hedges for hedge accounting treatment under FASB ASC 815. Therefore, changes in the fair value of 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, 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 Condensed Consolidated Statements of Operations relating to commodity swaps are (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Change in fair value of derivatives	$ (1.6)	$ (0.2)	$ (16.0)	$ (6.4)
Realized gain on derivatives	1.1	5.4	9.4	13.0
Gain (loss) on derivative activity	$ (0.5)	$ 5.2	$ (6.6)	$ 6.6

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

	September 30, 2016	December 31, 2015
Fair value of derivative assets — current	$ 4.3	$ 16.8
Fair value of derivative liabilities — current	(6.5)	(2.9)
Fair value of derivative liabilities — long term	—	(0.1)
Net fair value of derivatives	$ (2.2)	$ 13.8

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 in the Condensed Consolidated Statement of Operations. We estimate the fair value of all of our derivative contracts using actively quoted prices. The total estimated fair value liability of derivative contracts of $2.2 million as of September 30, 2016 has a maturity date of less than one year.

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at September 30, 2016. The remaining term of the contracts extend no later than September 2017.

		September 30, 2016		
Commodity	Instruments	Unit	Volume	Fair Value
			(In millions)	
NGL (short contracts)	Swaps	Gallons	(27.8)	$ 0.8
NGL (long contracts)	Swaps	Gallons	5.7	(0.4)
Natural Gas (short contracts)	Swaps	MMBtu	(9.3)	0.4
Natural Gas (long contracts)	Swaps	MMBtu	7.1	(2.6)
Condensate (short contracts)	Swaps	MMbbls	(0.1)	(0.4)
Total fair value of derivatives				$ (2.2)

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 two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. We have entered into Master International Swaps and Derivatives Association Agreements ("ISDAs") that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing swap contracts, our maximum loss as of September 30, 2016 of $4.3 million would be reduced to $1.6 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

Interest Rate Swaps

We entered into interest rate swaps during April and May 2015 in connection with the issuance of the 2025 Notes in May 2015. Additionally, we entered into interest rate swaps during July 2016 in connection with the issuance of the 2026 Notes in July 2016. We have no open interest rate swap positions as of September 30, 2016

The impact of the interest rate swaps on net income is included in other income (expense) in the Condensed Consolidated Statement of Operations as part of interest expense, net, as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Settlement gains on derivatives	$ 0.4	$ —	$ 0.4	$ 3.6

(12) Fair Value Measurements

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

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

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

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

	September 30, 2016 Level 2	December 31, 2015 Level 2
Commodity Swaps*	$ (2.2)	$ 13.8
Total	$ (2.2)	$ 13.8

* The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for our and/or the counterparty credit risk as required under FASB ASC 820.

Fair Value of Financial Instruments

We have determined the estimated fair value of our financial instruments using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount we could realize upon the sale or refinancing of such financial instruments (in millions):

	September 30, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,222.8	$ 3,101.4	$ 3,066.8	$ 2,585.5
Installment Payables	$ 459.8	$ 464.5	$ —	$ —
Obligations under capital lease	$ 10.5	$ 9.7	$ 16.7	$ 15.6

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 $75.0 million and $414.0 million in outstanding borrowings under our revolving credit facility as of September 30, 2016 and December 31, 2015, respectively. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. Under senior unsecured notes we had total borrowings of $3.1 billion and $2.7 billion as of September 30, 2016 and December 31, 2015, respectively, maturing between 2019 and 2045 with fixed interest rates ranging from 2.7% to 7.1%. The fair value of all senior unsecured notes and installment payables as of September 30, 2016 and December 31, 2015 was based on Level 2 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) Severance and Change in Control Agreements

Certain members of our management are parties to severance and change of control agreements with the Operating Partnership. The severance and change in control agreements provide those individuals with severance payments in certain circumstances and prohibit such individual from, among other things, competing with our general partner or its affiliates during his or her employment. In addition, the severance and change of control agreements prohibit subject individuals from, among other things, disclosing confidential information about our general partner or its affiliates or interfering with a client or customer of our general partner or its affiliates, in each case during his or her employment and for certain periods (including indefinite periods) following the termination of such person's employment.

(b) Environmental Issues

The operation of pipelines, plants and other facilities for the gathering, processing, transmitting or disposing of natural gas, NGLs, crude oil, condensate, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows. In February 2016, a spill occurred at our Kill Buck Station in our Ohio operations. State and federal agencies were notified and clean-up response efforts were promptly executed, which significantly lessened the impact of the spill. On April 7, 2016, the state agency determined that the clean-up recovery efforts were completed and has internally transitioned monitoring to their water quality division. We do not anticipate a material fine or penalty by either the state or federal agencies. In the third quarter of 2016, in connection with the transition to our operational control of E2 Appalachian Compression, LLC in and preparation to commence operational control of E2 Ohio Compression, LLC, we discovered instances of noncompliance with air regulations and permits. This noncompliance was self-reported to the Ohio Environmental Protection Agency

("OEPA"), resulting in the issuance of notices of violations ("NOVs"). We and E2 Ohio are taking appropriate measures to achieve compliance with applicable requirements and cooperating with the OEPA to resolve the NOVs, and, while we do not yet have information concerning any fine or penalty that may be assessed, we do not believe any such fine or penalty will be material to our operations. On July 29, 2016, after concluding a multi-year internal environmental compliance assessment of our Louisiana operations, we made an offer of \$0.1 million in the form of a Global Settlement to the Louisiana Department of Environmental Quality ("LDEQ") to resolve environmental noncompliance discovered or investigated during our assessment, which involved several of our Louisiana facilities. The noncompliance proposed to be covered by the Global Settlement include noncompliance that was self-reported to the LDEQ as the result of our assessment as well as noncompliance that was the subject of notices of potential violations and NOVs that we received from the LDEQ during the assessment time frame. We have taken the appropriate measures to resolve the instances of noncompliance, and we will continue to work with the LDEQ with respect to the proposed Global Settlement. Additionally, although the spill that previously occurred in our West Virginia operations in the third quarter of 2015 is still pending, we do not believe that any fine or penalty that may be issued will be material to our operations. Lastly, we continue to work with Pipeline and Hazardous Materials Safety Administration regarding the notice of potential violation discussed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

(c) Litigation Contingencies

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

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

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

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

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs, resulting in damage to certain of our facilities. We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, LLC ("Texas Brine"), the operator of a failed cavern in the area and its insurers, seeking recovery for these losses. We have also sued Occidental Chemical Company and Legacy Vulcan Corp. f/k/a Vulcan Materials Company, two Chlor-Alkali plant operators that participated in Texas Brine's operational decisions regarding the mining of the failed cavern. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and have also sued our insurers. In August 2014, we received a partial settlement with respect to the Texas Brine claims in the amount of \$6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

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

(14) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served. Our reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in north Texas, south Texas and the Permian Basin in west Texas ("Texas"), the pipelines and processing plants located in Louisiana and NGL assets located in south Louisiana ("Louisiana"), natural gas gathering and processing operations located throughout Oklahoma ("Oklahoma") and crude rail, truck, pipeline and barge facilities in west Texas, south Texas, Louisiana and 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.

Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist primarily of cash, property and equipment, including software, for general corporate support, debt financing costs and unconsolidated affiliate investments in HEP and GCF. We evaluate the performance of our operating segments based on operating revenues and segment profits.

Summarized financial information concerning our reportable segments is shown in the following tables:

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
			(In millions)			
Three Months Ended September 30, 2016						
Product sales	$ 61.3	$ 430.9	$ 16.2	$ 262.6	$ —	$ 771.0
Product sales-affiliates	81.9	24.4	36.0	—	(99.2)	43.1
Midstream services	27.5	57.2	24.2	16.8	—	125.7
Midstream services-affiliates	109.5	29.9	47.7	5.2	(27.0)	165.3
Cost of sales	(134.1)	(471.5)	(58.3)	(250.5)	126.2	(788.2)
Operating expenses	(42.9)	(23.5)	(12.6)	(19.0)	—	(98.0)
Loss on derivative activity	—	—	—	—	(0.5)	(0.5)
Segment profit	$ 103.2	$ 47.4	$ 53.2	$ 15.1	$ (0.5)	$ 218.4
Depreciation and amortization	$ (48.7)	$ (28.8)	$ (35.6)	$ (10.7)	$ (2.4)	$ (126.2)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 51.8	$ 15.4	$ 58.3	$ 12.8	$ 8.6	$ 146.9
Three Months Ended September 30, 2015						
Product sales	$ 106.9	$ 399.0	$ 3.9	$ 353.7	$ —	$ 863.5
Product sales-affiliates	35.3	17.6	4.6	0.4	(17.6)	40.3
Midstream services	20.3	63.3	9.4	18.3	—	111.3
Midstream services-affiliates	111.6	5.1	34.5	3.6	(4.5)	150.3
Cost of sales	(124.5)	(415.2)	(9.4)	(334.8)	22.1	(861.8)
Operating expenses	(44.3)	(27.2)	(7.2)	(26.3)	—	(105.0)
Gain on derivative activity	—	—	—	—	5.2	5.2
Segment profit	$ 105.3	$ 42.6	$ 35.8	$ 14.9	$ 5.2	$ 203.8
Depreciation and amortization	$ (44.4)	$ (27.4)	$ (11.9)	$ (12.9)	$ (1.8)	$ (98.4)
Impairments	$ —	$ (576.1)	$ —	$ (223.1)	$ —	$ (799.2)
Goodwill	$ 1,186.8	$ 210.7	$ 190.3	$ 142.1	$ —	$ 1,729.9
Capital expenditures	$ 29.0	$ 13.5	$ 19.7	$ 38.6	$ 3.9	$ 104.7

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
			(In millions)			
Nine Months Ended September 30, 2016						
Product sales	$ 165.7	$ 1,118.1	$ 32.9	$ 781.1	$ —	$ 2,097.8
Product sales-affiliates	191.9	47.0	69.1	1.1	(209.8)	99.3
Midstream services	78.1	165.1	57.3	48.0	—	348.5
Midstream services-affiliates	331.7	68.1	134.4	14.4	(60.1)	488.5
Cost of sales	(329.0)	(1,199.1)	(109.2)	(739.4)	269.9	(2,106.8)
Operating expenses	(125.2)	(72.2)	(37.2)	(61.7)	—	(296.3)
Loss on derivative activity	—	—	—	—	(6.6)	(6.6)
Segment profit	$ 313.2	$ 127.0	$ 147.3	$ 43.5	$ (6.6)	$ 624.4
Depreciation and amortization	$ (143.6)	$ (86.7)	$ (104.2)	$ (31.7)	$ (6.8)	$ (373.0)
Impairments	$ (473.1)	$ —	$ —	$ (93.2)	$ —	$ (566.3)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 132.3	$ 52.2	$ 190.6	$ 17.0	$ 15.4	$ 407.5
Nine Months Ended September 30, 2015						
Product sales	$ 237.3	$ 1,173.6	$ 2.4	$ 1,075.5	$ —	$ 2,488.8
Product sales-affiliates	91.5	37.4	10.2	0.8	(50.3)	89.6
Midstream services	76.2	184.5	29.9	60.7	—	351.3
Midstream services-affiliates	342.5	14.3	94.7	10.6	(12.8)	449.3
Cost of sales	(305.1)	(1,210.4)	(14.6)	(1,020.4)	63.1	(2,487.4)
Operating expenses	(136.9)	(78.7)	(23.3)	(73.7)	—	(312.6)
Gain on derivative activity	—	—	—	—	6.6	6.6
Segment profit	$ 305.5	$ 120.7	$ 99.3	$ 53.5	$ 6.6	$ 585.6
Depreciation and amortization	$ (123.6)	$ (81.8)	$ (37.2)	$ (41.5)	$ (5.0)	$ (289.1)
Impairments	$ —	$ (576.1)	$ —	$ (223.1)	$ —	$ (799.2)
Goodwill	$ 1,186.8	$ 210.7	$ 190.3	$ 142.1	$ —	$ 1,729.9
Capital expenditures	$ 183.4	$ 43.4	$ 37.2	$ 170.6	$ 10.6	$ 445.2

The table below presents information about segment assets as of September 30, 2016 and December 31, 2015:

Segment Identifiable Assets:	September 30, 2016	December 31, 2015
Texas	$ 3,195.1	$ 3,709.5
Louisiana	2,312.6	2,309.3
Oklahoma	2,451.8	873.4
Crude and Condensate	765.8	898.0
Corporate	350.6	302.6
Total identifiable assets	$ 9,075.9	$ 8,092.8

The following table reconciles the segment profits reported above to the operating income (loss) as reported in the Condensed Consolidated Statements of Operations (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Segment profits	$ 218.4	$ 203.8	$ 624.4	$ 585.6
General and administrative expenses	(28.3)	(33.5)	(90.6)	(102.3)
Gain (loss) on disposition of assets	3.0	(3.2)	2.9	(3.2)
Depreciation and amortization	(126.2)	(98.4)	(373.0)	(289.1)
Impairments	—	(799.2)	(566.3)	(799.2)
Operating income (loss)	$ 66.9	$ (730.5)	$ (402.6)	$ (608.2)

(15) Supplemental Cash Flow Information

The following schedule summarizes non-cash financing activities for the period presented:

	Nine Months Ended September 30,	
	2016	2015
	(In millions)	
Non-cash financing activities:		
Installment payable, net of discount of $79.1 million (1)	$ 420.9	$ —
Non-cash issuance of common units (2)	—	180.0
Non-cash issuance of Class C Common Units (2)	—	180.0
Contribution from ENLC (3)	237.1	—
Non-cash adjustment of interest in Midstream Holdings (4)	—	66.5

(1) We incurred installment purchase obligations, net of discount assuming payments of $250.0 million are made on January 7, 2017 and 2018, payable to the seller in connection with the Tall Oak acquisition. See Note 3 - Acquisitions for further discussion.
(2) Non-cash common units and Class C Common Units were issued as partial consideration for the Coronado acquisition.
(3) Contribution from ENLC in connection with the acquisition of Tall Oak. See Note 3 - Acquisitions for further discussion.
(4) Non-cash adjustment to reflect recast of the interests in EnLink Midstream Holdings, LP acquired on February 17, 2015.

(16) Other Information

The following table presents additional detail for certain balance sheet captions.

Other Current Liabilities

Other current liabilities consisted of the following:

	September 30, 2016	December 31, 2015
	(in millions)	
Accrued interest	$ 58.0	$ 23.2
Accrued wages and benefits, including taxes	13.7	27.7
Accrued ad valorem taxes	32.9	27.0
Capital expenditure accruals	35.3	22.3
Onerous performance obligations	16.1	17.0
Other	40.2	57.2
Other current liabilities	$ 196.2	$ 174.4

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

In this report, the term "Partnership," as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, L.P. and EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O."). EnLink Oklahoma T.O. is sometimes used to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP together with its consolidated subsidiaries.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission, fractionation, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 11,000 miles of pipelines, 21 processing facilities with approximately 4.4 billion cubic feet per day of processing capacity, 7 fractionators with approximately 260,000 barrels per day of fractionation capacity, as well as barge and rail terminals, product storage facilities, purchase and marketing capabilities, brine disposal wells, a crude oil trucking fleet and equity investments in certain private midstream companies. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments: (1) Texas, which includes our natural gas gathering, processing and transmission activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes our natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK"), South Central Oklahoma Oil Province ("SCOOP") and Central Northern Oklahoma Woodford ("CNOW") Shale areas; (3) Louisiana, which includes our natural gas pipelines, natural gas processing plants and NGL assets located in Louisiana; (4) Crude and Condensate, which includes our Ohio River Valley ("ORV") crude oil, condensate and brine disposal activities in the Utica and Marcellus Shales, E2 Appalachian Compression, LLC, our equity interests in E2 Energy Services, LLC and E2 Ohio Compression, LLC (collectively, "E2"), our crude oil operations in the Permian Basin and our crude oil activities associated with the Victoria Express Pipeline and related truck terminal and storage assets ("VEX") located in the Eagle Ford Shale; and (5) Corporate, which includes our unconsolidated affiliate investments in Howard Energy Partners ("HEP") in the Eagle Ford Shale, our contractual right to the economic burdens and benefits associated with Devon's ownership interest in Gulf Coast Fractionators ("GCF") in south Texas and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to gather, process, transport or market natural gas, NGLs, crude oil and condensate using our assets for a fee. We earn our fees through various contractual arrangements, which include stated fixed-fee contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin as 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. 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 97% of our gross operating margin was derived from fee-based services with no direct commodity exposure for the nine months ended September 30, 2016. We reflect revenue as "Product sales" and "Midstream services" on the Condensed Consolidated Statements of Operations.

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

We generate revenues from eight primary sources:

- gathering and transporting natural gas and NGLs 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; and

· providing brine disposal services.

· providing gas, crude, and NGL storage.

We typically gather or transport gas owned by others through our facilities for a fee. We also buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the same market index. The fixed discount difference to a market index represents the fee for using our assets. 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. Our gathering and transportation fee related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time, the supplies that we have under contract may decline due to reduced drilling or other causes, and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

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 with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices on our North Texas Pipeline and sell the gas into a different market area index. We realize a 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 September 30, 2016, the balance sheet reflects a liability of $49.3 million related to this performance obligation. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

We typically transport and fractionate or store NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. We also buy mixed NGLs from our suppliers 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. The operating results of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With our fractionation business, we also have the opportunity for product upgrades for each of the discrete NGL products. The fees we earn on the product upgrade from this fractionation business are higher during periods with higher liquids prices.

We generally gather or transport crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a fee. We also buy crude oil and condensate from a producer at a fixed discount to a market index, 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 fee we will receive for each crude oil and condensate transaction.

We realize gross operating margins from our processing services primarily through different contractual arrangements: processing margins (“margin”), percentage of liquids (“POL”), percentage of proceeds (“POP”) or fixed-fee based. Under margin contract arrangements our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. 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. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk - Commodity Price Risk."

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

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

Recent Developments

Acquisition

Tall Oak. On January 7, 2016, we and EnLink Midstream, LLC ("ENLC") acquired an 84% and 16% interest, respectively, in EnLink Oklahoma T.O. for approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The final installment of $500.0 million is due no later than the first anniversary of the closing date with the option to defer $250.0 million of the final installment up to 24 months following the closing date. The installment payables are valued net of discount within the total purchase price.

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

EnLink Oklahoma T.O. assets serve gathering and processing needs in the growing STACK and CNOW plays in Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that have a remaining weighted-average term of approximately 13 years. EnLink Oklahoma T.O. assets are strategically located in the core areas of the STACK and CNOW plays and include:

- *Chisholm Plant.* The Chisholm Plant, which serves the STACK play, is a cryogenic gas processing plant with a current capacity of 120 MMcf/d. Depending on future volume requirements, the Chisholm Plant could be expanded by an additional 600 MMcf/d for a total processing capacity of 700 MMcf/d. The plant is connected to a 200-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.

  We plan to construct a new cryogenic gas processing plant, referred to as Chisholm II, that will provide an additional 200 MMcf/d of processing capacity and will be tied to new and existing pipelines in the STACK and SCOOP play. The planned expansion is scheduled to be completed during the first quarter of 2017. The new capacity will be supported by long-term contracts.

- *Battle Ridge Plant.* The Battle Ridge Plant, which provides us with an entry into the CNOW play, is a cryogenic gas processing plant with a current capacity of 75 MMcf/d. Depending on future volume requirements, the Battle Ridge Plant could be expanded by an additional 400 MMcf/d for a total processing capacity of 475 MMcf/d. The plant is connected to a 175-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.

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

Organic Growth

Greater Chickadee Crude Oil Gathering System. We are constructing a new crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin that we refer to as “Greater Chickadee.” Greater Chickadee will include over 150 miles of high- and low-pressure pipelines that will transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area. Greater Chickadee also includes the construction of multiple central tank batteries and pump, truck injection, and storage stations to maximize shipping and delivery options for our producer customers. The initial phase of our Greater Chickadee transportation service will begin in November 2016 with full service expected in the first quarter of 2017.

Riptide Processing Plant. In April 2016, we completed construction of the Riptide processing plant in the Permian Basin. The Riptide plant was part of the Coronado Midstream acquisition that was completed in March 2015. The Riptide plant is integrated with our Midland Basin system, and key customers include Diamondback Energy, Inc., RSP Permian, Inc. and Concho Resources, Inc.

Delaware Basin Joint Venture. On August 1, 2016, we formed a joint venture (the “Delaware Basin JV”) with an affiliate of NGP Natural Resources XI, L.P. (“NGP”) to operate and expand our natural gas, natural gas liquids, and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1 percent by us and 49.9 percent by NGP. We contributed approximately $221.0 million of existing assets net of depreciation to the Delaware Basin JV and committed an additional $285.0 million in capital to fund potential future development projects and potential acquisitions. NGP committed an aggregate of approximately $400.0 million of capital, including an initial contribution of $114.3 million, which the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent to date on existing assets and ongoing projects. In addition to the initial contributions, we and NGP contributed $23.4 million to the Delaware Basin JV in the third quarter of 2016. As part of this agreement, NGP granted us call rights beginning in 2021 to acquire increasing portions of NGP’s interest in the joint venture at a price based upon a fixed multiple.

Lobo II Natural Gas Gathering and Processing Facility. In the first quarter of 2016, we commenced construction of a new cryogenic gas processing plant and a gas gathering system in the Delaware Basin. We contributed these assets to the Delaware Basin JV. Under the joint venture agreement we continue to serve as construction manager of the project. The plant will initially provide 60 MMcf/d of processing capacity (with a potential capacity of 120 MMcf/d) and will be tied to approximately 75 miles of new pipeline located in both in Texas and New Mexico that is also under construction. The plant and Texas portion of the pipeline was completed in the second half of 2016 with the remaining New Mexico pipeline to be completed in the first quarter of 2017. The cryogenic gas processing plant and gas gathering system are part of the assets contributed to the Delaware Basin JV.

Marathon Petroleum Joint Venture. We have entered into a series of agreements with a subsidiary of Marathon Petroleum Corporation (“Marathon Petroleum”) to create a 50/50 joint venture named Ascension Pipeline Company, LLC (“Ascension JV”). In the third quarter of 2016, the joint venture commenced construction of a new 30-mile NGL pipeline connecting our existing Riverside fractionation and terminal complex to Marathon Petroleum’s Garyville refinery located on the Mississippi River. This bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, we will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

HEP. During 2016, we made contributions to HEP, primarily to fund our equity share of HEP’s Nueva Era Pipeline. The Nueva Era Pipeline is a 50/50 joint venture between HEP and Mexico-based energy and services firm, Grupo Clisa, that will connect HEP’s existing Webb County hub in South Texas directly to the Mexican National Pipeline System in Monterrey, Mexico. Mexico’s Comisión Federal de Electricidad will be the foundation shipper on the approximately 200-mile, 30-inch pipeline and will transport 504 MMcf/d on the system for a 25-year term. For the three and nine months ended September 30, 2016, we contributed $3.2 million and $45.0 million. Included in our contributions for the nine months ended September 30, 2016 is our purchase of preferred units from HEP for a contribution of $32.7 million, and these preferred units were redeemed in the third quarter of 2016.

Issuance of Senior Notes

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year, beginning January 15, 2017. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our revolving credit facility and for general partnership purposes.

Issuance of Units

Equity Distribution Agreement. In November 2014, the Partnership entered into an equity distribution agreement (the "BMO EDA") with BMO Capital Markets Corp. and certain other sales agents to sell up to $350.0 million in aggregate gross sales of the Partnership's common units from time to time through an "at the market" equity offering program. The Partnership may also sell common units to any sales agent as principal for the sales agent's own account at a price agreed upon at the time of sale. The Partnership has no obligation to sell any of the common units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA.

For the nine months ended September 30, 2016, we sold an aggregate of 6.7 million common units under the BMO EDA, generating proceeds of approximately $110.6 million (net of approximately $1.1 million of commissions). We used the net proceeds for general partnership purposes. As of September 30, 2016, approximately $205.3 million remains available to be issued under the BMO EDA.

Issuance of Preferred Units

On January 7, 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing limited partner interests in our partnership (the "Preferred Units") to Enfield Holdings, L.P. ("Enfield") in a private placement for a cash purchase price of $15.00 per Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the acquisition of EnLink Oklahoma T.O. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield.

The Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, at any time after the record date for the quarter ending June 30, 2017 (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Preferred Units would then convert and (ii) the number of Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

As a holder of Preferred Units, Enfield is entitled to receive a quarterly distribution, subject to certain adjustments, equal to (x) during the quarter ending March 31, 2016 through the quarter ending June 30, 2017, an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Preferred Units and (y) thereafter, at an annual rate of 7.5% on the Issue Price payable in cash (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) an annual rate of 1.0% of the Issue Price and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, depreciation and amortization, or adjusted EBITDA, distributable cash flow and gross operating margin.

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus interest expense, provision for income taxes, depreciation and amortization expense, impairment expense, unit-based compensation, (gain) loss on non-cash derivatives, (gain) loss on disposition of assets, successful transaction costs, accretion expense associated with asset retirement obligations, reimbursed employee costs, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, and income (loss) from unconsolidated affiliate investments. Adjusted EBITDA is a primary metric used in our credit facility and 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, 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:

Reconciliation of net income (loss) to adjusted EBITDA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Net income (loss)	$ 17.5	$ (755.2)	$ (542.2)	$ (665.8)
Interest expense	48.0	30.2	137.9	71.5
Depreciation and amortization	126.2	98.4	373.0	289.1
Impairments	—	799.2	566.3	799.2
(Income) loss from unconsolidated affiliate investments	(1.1)	(6.4)	0.5	(16.1)
Distribution from unconsolidated affiliate investments (1)	4.7	12.2	19.6	31.4
(Gain) loss on disposition of assets	(3.0)	3.2	(2.9)	3.2
Unit-based compensation	7.3	7.3	22.5	28.6
Income taxes	2.6	1.0	1.3	2.9
Loss on non-cash derivatives	1.6	0.2	16.0	6.4
Payments under onerous performance obligation offset to other current and long-term liabilities	(4.5)	(4.5)	(13.5)	(13.5)
Other (2)	1.5	1.4	7.5	10.8
Adjusted EBITDA before non-controlling interest	$ 200.8	$ 187.0	$ 586.0	$ 547.7
Non-controlling interest share of adjusted EBITDA (3)	(3.3)	0.3	(6.1)	0.3
Transferred interest adjusted EBITDA (4)	—	—	—	(55.8)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 197.5	$ 187.3	$ 579.9	$ 492.2

(1) Distributions for the three and nine months ended September 30, 2016 do not include $32.7 million of distributions received from HEP during the third quarter 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(2) Includes the following: accretion expense associated with asset retirement obligations; reimbursed employee costs from Devon and LPC, which are costs reimbursed to us by previous employer pursuant to acquisition or merger; successful acquisition transaction costs which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs; and non-cash rent which relates to lease incentives pro-rated over the lease term.

(3) Non-controlling interest share of adjusted EBITDA includes ENLC's 16% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV and the non-controlling interest share of adjusted EBITDA from the E2 entities.

(4) Represents recast adjusted EBITDA from assets acquired from ENLC and Devon in drop down transactions during the first half of 2015 for the period prior to the date of the drop down transactions.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA (as defined above), net to the Partnership, less interest expense (excluding amortization of the Tall Oak acquisition installment payable discount), adjustments for the mandatorily redeemable non-controlling interest, cash taxes and other, and maintenance capital expenditures. 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 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 and other gathering, well connections, compression and processing assets up to their original operating capacity, to maintain 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 financial performance 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 income 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

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(in millions)			
Net cash provided by operating activities	$ 209.6	$ 215.7	$ 509.2	$ 508.0
Interest expense, net (1)	34.5	28.8	98.7	73.5
Current income tax	2.6	1.0	1.6	2.9
Distributions from unconsolidated affiliate investment in excess of earnings (2)	4.1	5.4	18.9	14.3
Other (3)	1.0	1.8	6.3	10.4
Changes in operating assets and liabilities which provided cash:				
Accounts receivable, accrued revenues, inventories and other	(0.2)	(66.9)	14.2	(105.9)
Accounts payable, accrued gas and crude oil purchases and other (4)	(50.8)	1.2	(62.9)	44.5
Adjusted EBITDA before non-controlling interest	$ 200.8	$ 187.0	$ 586.0	$ 547.7
Non-controlling interest share of adjusted EBITDA (5)	(3.3)	0.3	(6.1)	0.3
Transferred interest adjusted EBITDA (6)	—	—	—	(55.8)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 197.5	$ 187.3	$ 579.9	$ 492.2
Interest expense	(48.0)	(30.2)	(137.9)	(71.5)
Amortization of Tall Oak installment payable discount included in interest expense (7)	13.3	—	39.0	—
Non-cash adjustment for mandatorily redeemable non-controlling interest	—	1.3	0.3	(2.1)
Interest Rate Swap (8)	0.4	—	0.4	(3.6)
Cash taxes and other	(2.6)	(1.0)	(1.6)	(2.5)
Maintenance capital expenditures	(6.2)	(9.6)	(19.3)	(32.0)
Distributable cash flow	$ 154.4	$ 147.8	$ 460.8	$ 380.5

(1) Net of amortization of debt issuance costs, discount and premium, and valuation adjustment for mandatorily redeemable non-controlling interest included in interest expense but not included in net cash provided by operating activities.
(2) Distributions for the three and nine months ended September 30, 2016 do not include $32.7 million of distributions received from HEP during the third quarter 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.
(3) Includes the following: reimbursed employee costs from Devon and LPC, which are costs reimbursed to us by previous employer pursuant to acquisition or merger; and successful acquisition transaction costs which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs.
(4) Net of payments under onerous performance obligation offset to other current and long-term liabilities.
(5) Non-controlling interest share of adjusted EBITDA includes ENLC's 16% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV and the non-controlling interest share of adjusted EBITDA from the E2 entities.
(6) Represents recast adjusted EBITDA from assets acquired from ENLC and Devon in drop down transactions during the first half of 2015 for the period prior to the date of the drop down transactions.
(7) Amortization of the Tall Oak 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 Tall Oak assets.
(8) During the third quarter of 2016 and second quarter of 2015, we entered into interest rate swap arrangements to mitigate our exposure to interest rate movements prior to our note issuances. The gain on settlement of the interest rate swaps was considered excess proceeds for the note issuance and is therefore excluded from distributable cash flow.

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 our business is generally to purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. Operating expense is a separate measure used by 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Operating income (loss)	$ 66.9	$ (730.5)	$ (402.6)	$ (608.2)
Add (deduct):				
Operating expenses	98.0	105.0	296.3	312.6
General and administrative expenses	28.3	33.5	90.6	102.3
(Gain) loss on disposition of assets	(3.0)	3.2	(2.9)	3.2
Depreciation and amortization	126.2	98.4	373.0	289.1
Impairments	—	799.2	566.3	799.2
Gross operating margin	$ 316.4	$ 308.8	$ 920.7	$ 898.2

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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions, except volumes)			
Texas Segment				
Revenues	$ 280.2	$ 274.1	$ 767.4	$ 747.5
Cost of sales	(134.1)	(124.5)	(329.0)	(305.1)
Total gross operating margin	$ 146.1	$ 149.6	$ 438.4	$ 442.4
Louisiana Segment				
Revenues	$ 542.4	$ 485.0	$ 1,398.3	$ 1,409.8
Cost of sales	(471.5)	(415.2)	(1,199.1)	(1,210.4)
Total gross operating margin	$ 70.9	$ 69.8	$ 199.2	$ 199.4
Oklahoma Segment				
Revenues	$ 124.1	$ 52.4	$ 293.7	$ 137.2
Cost of sales	(58.3)	(9.4)	(109.2)	(14.6)
Total gross operating margin	$ 65.8	$ 43.0	$ 184.5	$ 122.6
Crude and Condensate Segment				
Revenues	$ 284.6	$ 376.0	$ 844.6	$ 1,147.6
Cost of sales	(250.5)	(334.8)	(739.4)	(1,020.4)
Total gross operating margin	$ 34.1	$ 41.2	$ 105.2	$ 127.2
Corporate				
Revenues	$ (126.7)	$ (16.9)	$ (276.5)	$ (56.5)
Cost of sales	126.2	22.1	269.9	63.1
Total gross operating margin	$ (0.5)	$ 5.2	$ (6.6)	$ 6.6
Total				
Revenues	$ 1,104.6	$ 1,170.6	$ 3,027.5	$ 3,385.6
Cost of sales	(788.2)	(861.8)	(2,106.8)	(2,487.4)
Total gross operating margin	$ 316.4	$ 308.8	$ 920.7	$ 898.2
Midstream Volumes:				
Texas				
Gathering and Transportation (MMBtu/d)	2,580,300	2,640,300	2,657,600	2,705,900
Processing (MMBtu/d)	1,172,900	1,244,100	1,188,100	1,214,500
Louisiana				
Gathering and Transportation (MMBtu/d)	1,754,400	1,516,400	1,602,400	1,444,700
Processing (MMBtu/d)	493,900	509,100	496,400	488,200
NGL Fractionation (Gals/d)	5,259,400	6,370,600	5,194,700	5,957,000
Oklahoma				
Gathering and Transportation (MMBtu/d)	633,000	391,100	620,300	411,800
Processing (MMBtu/d)	583,200	348,900	571,800	325,500
Crude and Condensate				
Crude Oil Handling (Bbls/d)	72,800	147,300	98,300	130,800
Brine Disposal (Bbls/d)	3,700	4,200	3,500	3,900

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

Gross Operating Margin. Gross operating margin was $316.4 million for the three months ended September 30, 2016 compared to $308.8 million for the three months ended September 30, 2015, an increase of $7.6 million, or 2.5% due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment decreased $3.5 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. The Texas segment decrease was attributable primarily to $8.7 million decrease in gross operating margin from our north Texas processing, gathering and transmission assets due primarily to volume declines and the expiration of certain higher margin contracts. This decrease was partially offset by gross operating margin contributions totaling $3.7 million during 2016 from the Matador and Deadwood assets acquired in the fourth quarter of 2015. In addition, volume growth in the Midland Basin resulted in an additional increase in gross operating margin of $1.6 million between periods.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $1.1 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. The gross operating margin from our NGL business increased $2.6 million while the gross operating margin for the Louisiana gas business declined $1.5 million.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $22.8 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. This increase was driven by a gross operating margin contribution of $24.8 million from the EnLink Oklahoma T.O. assets acquired in January 2016. This increase was partially offset by a decline in gross operating margin of $2.5 million at the Northridge gathering and processing assets as a result of a decline in volumes and a rate reduction on a third-party contract.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $7.1 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. The decrease is primarily the result of volume declines throughout the Crude and Condensate segment.

- *Corporate Segment.* The Corporate segment included a loss from derivative activity of $0.5 million for the three months ended September 30, 2016 compared to a gain of $5.2 million for the three months ended September 30, 2015 due primarily to realized gains on commodity swaps during the three months ended September 30, 2015.

Operating Expenses. Operating expenses were $98.0 million for the three months ended September 30, 2016 compared to $105.0 million for the three months ended September 30, 2015, a decrease of $7.0 million, or 6.7%. The primary contributors to the total decrease by segment were as follows:

	Three Months Ended September 30,		Change	
	2016	2015	$	%
	(in millions)			
Texas Segment	$ 42.9	$ 44.3	$ (1.4)	(3.2)%
Louisiana Segment	23.5	27.2	(3.7)	(13.6)%
Oklahoma Segment	12.6	7.2	5.4	75.0 %
Crude and Condensate Segment	19.0	26.3	(7.3)	(27.8)%
Total	$ 98.0	$ 105.0	$ (7.0)	(6.7)%

- *Texas Segment.* Operating expenses in the Texas segment decreased $1.4 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. This decrease was primarily attributable to cost reduction measures.

- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $3.7 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. This decrease was primarily attributable to cost reduction measures.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $5.4 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. Of this increase, $4.8 million was attributable to the January 2016 Tall Oak acquisition.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $7.3 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. This decrease was due primarily to decreased trucking volumes, which decreased labor, fuel and contractor costs, in addition to overall cost reduction measures in the Crude and Condensate segment.

General and Administrative Expenses. General and administrative expenses were $28.3 million for the three months ended September 30, 2016 compared to $33.5 million for the three months ended September 30, 2015, a decrease of $5.2 million, or 15.5%. The primary contributors to the decrease were as follows:

- our wages and salaries decreased $4.5 million due to decreases in bonus expense and severance expense;
- our rent expense increased $1.7 million related to new office leases, which commenced during 2016;
- our bad debt expense decreased $0.8 million;
- our transaction costs related to acquisitions decreased $0.7 million; and
- our unit-based compensation expense decreased $0.6 million.

Depreciation and Amortization. Depreciation and amortization expenses were $126.2 million for the three months ended September 30, 2016 compared to $98.4 million for the three months ended September 30, 2015, an increase of $27.8 million, or 28.3%. Of this increase, $23.0 million was attributable to the acquisition of the EnLink Oklahoma T.O. assets and $2.0 million was attributable to the Matador acquisition. These increases were partially offset by a $3.5 million decrease in amortization attributable to the impairment of ORV intangible assets in August 2015. The remaining increase in depreciation and amortization expense was primarily attributable to additional assets placed in service.

Impairments. Impairment expense was $799.2 million for the three months ended September 30, 2015. During September 2015, we recognized an impairment on goodwill of $576.1 million related to our Louisiana segment and an impairment on intangible assets in our Crude and Condensate segment of $223.1 million.

Interest Expense. Interest expense was $48.0 million for the three months ended September 30, 2016 compared to $30.2 million for the three months ended September 30, 2015, an increase of $17.8 million, or 58.9%. Of the increase, $6.0 million was attributable to an increase in average debt, $1.4 million was attributable to a decrease in capitalized interest and $13.4 million was attributable to an increase in non-cash amortization of discount due to the Tall Oak acquisition installment payments. These increases were partially offset by a gain on the settlement of interest rate swaps of $0.4 million in 2016, changes in the valuation of our mandatorily redeemable interest in 2015 of $1.3 million. Net interest expense consisted of the following (in millions):

	Three Months Ended September 30,	
	2016	2015
Senior notes	$ 35.1	$ 30.0
Credit facility	2.2	1.3
Capitalized interest	(1.3)	(2.7)
Amortization of debt issue costs and net discounts (premium)	13.5	0.1
Cash settlements on interest rate swaps	(0.4)	—
Mandatory redeemable non-controlling interest	—	1.3
Other	(1.1)	0.2
Total	$ 48.0	$ 30.2

Income (loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $1.1 million for the three months ended September 30, 2016 compared to income of $6.4 million for the three months ended September 30, 2015, a decrease of $5.3 million. This decrease is due primarily to a $4.2 million decrease in income from our investment in HEP attributable to increased interest, depreciation, and amortization expense resulting from acquisitions.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Gross Operating Margin. Gross operating margin was $920.7 million for the nine months ended September 30, 2016 compared to $898.2 million for the nine months ended September 30, 2015, an increase of $22.5 million, or 2.5%, due to the following:

· *Texas Segment.* Gross operating margin in the Texas segment decreased $4.0 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. The Texas segment decrease was attributable to a $27.7 million decrease in gross operating margin due to volume declines and the expiration of certain higher margin contracts from our north Texas processing, gathering and transportation assets. This decrease was partially offset by gross operating margin contributions totaling $19.5 million from the Coronado assets acquired in March 2015 and the Matador and Deadwood assets acquired during the fourth quarter of 2015. In addition, volume growth in the Midland Basin resulted in an additional increase in gross operating margin of $4.5 million between periods.

· *Louisiana Segment.* The Louisiana segment had a slight decrease in gross operating margin of $0.2 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015.

· *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $61.9 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. This increase was driven by a gross operating margin contribution of $56.6 million from the EnLink Oklahoma T.O. assets acquired in January 2016. In addition, our gross operating margin from our Cana gathering and processing assets increased by $6.7 million between periods due primarily to increased volumes combined with the expansion of our compression facilities completed in October 2015.

· *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $22.0 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. A decrease of $14.4 million resulted from the termination of a customer contract during the second quarter of 2015, which included a $10.3 million early termination payment. The remaining decrease is primarily the result of volume declines throughout the Crude and Condensate segment.

· *Corporate Segment.* The Corporate segment included a loss from derivative activity of $6.6 million for the nine months ended September 30, 2016 compared to a gain of $6.6 million for the nine months ended September 30, 2015 due primarily to unrealized gains related to the changes in the fair value of our commodity swaps between periods.

Operating Expenses. Operating expenses were $296.3 million for the nine months ended September 30, 2016 compared to $312.6 million for the nine months ended September 30, 2015, a decrease of $16.3 million, or 5.2%. The primary contributors to the decrease by segment were as follows:

	Nine Months Ended September 30,		Change	
	2016	**2015**	**$**	**%**
		(in millions)		
Texas Segment	$ 125.2	$ 136.9	$ (11.7)	(8.5)%
Louisiana Segment	72.2	78.7	(6.5)	(8.3)%
Oklahoma Segment	37.2	23.3	13.9	59.7 %
Crude and Condensate Segment	61.7	73.7	(12.0)	(16.3)%
Total	$ 296.3	$ 312.6	$ (16.3)	(5.2)%

· *Texas Segment.* Operating expenses in the Texas segment decreased $11.7 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. The decrease was primarily attributable to lower operating costs of $19.7 million resulting from the timing of field work and overall cost reduction measures, including lower rental expense on compressors and lower materials and supplies expenses. These decreases were partially offset by a $7.5 million increase in operating expenses attributable to the March 2015 Coronado acquisition, the October 2015 Matador acquisition and the November 2015 Deadwood acquisition.

- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $6.5 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 due to overall cost reduction measures, including realized cost savings from materials and supplies, construction fees and services and labor. In addition, rental expense decreased $1.0 million due to rental equipment that was returned in the first quarter of 2016.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $13.9 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. The increase was primarily attributable to the January 2016 EnLink Oklahoma T.O. acquisition.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $12.0 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. This decrease was due primarily to decreased trucking volumes, which decreased labor, fuel and contractor costs, in addition to overall cost reduction measures in the Crude and Condensate segment.

General and Administrative Expenses. General and administrative expenses were $90.6 million for the nine months ended September 30, 2016 compared to $102.3 million for the nine months ended September 30, 2015, a decrease of $11.7 million, or 11.4%. The primary contributors to the decrease were as follows:

- our unit-based compensation expense decreased $7.1 million due primarily to bonuses being paid in the form of units that immediately vested in March 2015;

- our wages and salaries decreased by $2.9 million due to a decrease in bonus expense;

- our software consulting fees decreased $1.7 million;

- our bad debt expense decreased $1.4 million;

- our transition service fees related to acquisitions decreased by $1.0 million;

- our transaction costs related to acquisitions decreased by $1.0 million; and

- our rent expense increased $3.5 million related to the new office leases, which commenced during 2016.

Depreciation and Amortization. Depreciation and amortization expenses were $373.0 million for the nine months ended September 30, 2016 compared to $289.1 million for the nine months ended September 30, 2015, an increase of $83.9 million, or 29.0%. Of this increase, $65.0 million was attributable to the acquisition of the EnLink Oklahoma T.O. assets, $9.7 million was attributable to the Coronado assets and $6.3 million was attributable to the Matador assets. These increases were partially offset by a $14.3 million decrease in amortization attributable to the impairment of ORV intangible assets in August 2015. The remaining increase in depreciation and amortization expense was primarily attributable to assets placed in service.

Impairments. Impairment expense was $566.3 million for the nine months ended September 30, 2016 compared to $799.2 million for the nine months ended September 30, 2015, a decrease of $232.9 million, or 29.1%. During March 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments. During September 2015 we recognized an impairment on goodwill of $576.1 million related to our Louisiana segment and an impairment on intangible assets in our Crude and Condensate segment of $223.1 million. For more information, see “Critical Accounting Policies-Impairment of Goodwill” below.

Interest Expense. Interest expense was $137.9 million for the nine months ended September 30, 2016 compared to $71.5 million for the nine months ended September 30, 2015, an increase of $66.4 million, or 92.9%. Of the increase, $23.0 million was attributable to an increase in average debt in 2016 compared to 2015, $39.5 million was attributable to an increase in non-cash amortization primarily of discount due to the Tall Oak acquisition installment payments, $3.2 million was attributable to a decrease in gains on cash settlements on interest rate swaps in 2016 compared to 2015 and $2.3 million was attributable to an increase in non-cash interest expense related to the change in the valuation of the

Partnership's mandatorily redeemable non-controlling interest. Net interest expense consisted of the following (in millions):

	Nine Months Ended September 30,	
	2016	2015
Senior notes	$ 95.1	$ 75.9
Credit facility	9.6	5.8
Capitalized interest	(5.5)	(5.6)
Amortization of debt issue costs and net discounts (premium)	39.5	—
Cash settlements on interest rate swap	(0.4)	(3.6)
Mandatory redeemable non-controlling interest	0.3	(2.0)
Other	(0.7)	1.0
Total	$ 137.9	$ 71.5

Income (loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $0.5 million for the nine months ended September 30, 2016 compared to income of $16.1 million for the nine months ended September 30, 2015, a decrease of $16.6 million, or 103.1%. This decrease was due primarily to a decline of $8.8 million in income from our GCF investment due to a $5.6 million decrease in revenue as a result of lower pipeline and fractionator feed volume as well as a $3.3 million increase in operating costs driven by major scheduled maintenance on the fractionator during the first nine months of 2016. An additional decrease of $7.8 million was due to a decrease in net income from our HEP investment and is primarily attributable to increased interest, depreciation, and amortization expense resulting from acquisitions.

Critical Accounting Policies

Information regarding the Partnership's Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015, except as described below.

Impairment of Goodwill. We conduct our annual goodwill impairment test in the fourth quarter each year. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. During the first quarter of 2016, we determined that continued further weakness in the overall energy sector driven by low commodity prices together with a further decline in our unit price subsequent to year-end caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis on all reporting units.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows, including volume and price forecasts and estimated operating expense and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors.

Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair value of our Texas and Crude and Condensate reporting units were less than their respective carrying amounts, due primarily to changes in assumptions related to increases in discount rates. The second step of the goodwill impairment test measures the amount of impairment loss and involves allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit as if the reporting unit had been acquired in a business combination. Through the analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized for the three months ended March 31, 2016, which is included in our nine months ended September 30, 2016 impairments line item in the Condensed Consolidated Statements of Operations.

We concluded that the fair value of goodwill of our Oklahoma reporting unit substantially exceeded its carrying value, and the entire amount of goodwill disclosed on the Condensed Consolidated Balance Sheet associated with the remaining reporting unit is recoverable. However, the fair value of our Texas reporting unit is not substantially in excess of its carrying value. As of March 31, 2016, the fair value of our Texas reporting unit approximated its carrying value after considering the impairment loss above. As of September 30, 2016, we had $232.0 million of goodwill allocated to the Texas reporting unit.

Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to additional goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. The estimated fair value of our Texas reporting unit may be impacted in the future by a further decline in our unit price or a continuing prolonged period of lower commodity prices, which may adversely affect our estimate of future cash flows, both of which could result in future goodwill impairment charges for our Texas reporting unit.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $509.2 million for the nine months ended September 30, 2016 compared to $508.0 million for the nine months ended September 30, 2015. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2016	2015
Operating cash flows before working capital	$ 473.9	$ 460.1
Changes in working capital	35.3	47.9

The increase in operating cash flows before changes in working capital of $13.8 million from 2015 to 2016 is due primarily to an increase in gross operating margin from the acquisition of Coronado, Matador, Deadwood and EnLink Oklahoma T.O. assets, which is offset partially by a decrease in gross operating margin in our Crude and Condensate segment due to lower volumes and the termination of a customer contract during the second quarter of 2015. The changes in working capital for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 are due primarily 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 $1,181.4 million for the nine months ended September 30, 2016 and $774.3 million for the nine months ended September 30, 2015. Our primary investing cash flows were acquisition costs and capital expenditures, net of accrued amounts, as follows (in millions):

	Nine Months Ended September 30,	
	2016	2015
Growth capital expenditures	$ 404.4	$ 414.4
Maintenance capital expenditures	19.3	35.9
Proceeds from insurance settlement	(0.3)	—
Acquisition of business	769.3	330.6
Proceeds from sale of property	(4.7)	(0.4)
Investment in unconsolidated affiliate investments	45.0	8.1
Distribution from unconsolidated affiliate investments in excess of earnings	(51.6)	(14.3)
Total	$ 1,181.4	$ 774.3

Growth capital expenditures decreased $10.0 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The decrease is attributable primarily to the completions of the E2 compression and stabilization facilities and the VEX pipeline during 2015 in the Crude and Condensate segment and the completion of the Bearkat natural gas processing plant and rich gas gathering system during 2015 in the Texas segment. The decrease in expenditures due to the completion of these capital projects was offset partially by an increase in growth capital expenditures during the nine months ended September 30, 2016 in our Oklahoma segment for the EnLink Oklahoma T.O. assets.

Maintenance capital expenditures decreased $16.6 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. The decrease is primarily attributable to decreases in compressor overhauls and repairs in our Texas and Oklahoma segments due to a decrease in activity.

Acquisition expenditures increased $438.7 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. Acquisition expenditures during the nine months ended September 30, 2016 included the Tall Oak acquisition. Acquisition expenditures during the nine months ended September 30, 2015 included the LPC and Coronado acquisitions.

During the nine months ended September 30, 2016, we contributed $45.0 million to our unconsolidated investment in HEP. Included in our contributions is our purchase of preferred units from HEP for $32.7 million, these preferred units were redeemed in the third quarter of 2016.

Cash Flows from Financing Activities. Net cash provided by financing activities was $726.3 million and $281.6 million for the nine months ended September 30, 2016 and 2015, respectively. Our primary financing activities consist of the following (in millions):

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Net repayments on our credit facility	$ (339.2)	$ (62.1)
Unsecured senior notes borrowings	499.3	893.3
Net repayments under capital lease obligations	(3.2)	(2.5)
Debt financing costs	(4.6)	(9.5)
Proceeds from issuance of common units	110.6	12.9
Proceeds from issuance of preferred units	724.1	—
Contributions by non-controlling partners	179.4	12.2

For the nine months ended September 30, 2016, contributions by non-controlling partners included $137.7 million in contributions from NGP to the Delaware Basin JV, which consisted of an initial contribution of $114.3 million that the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent to date on existing assets and ongoing projects. In addition to NGP's initial contribution, we and NGP contributed $23.4 million to the Delaware Basin JV in the third quarter of 2016. Additional contributions include $13.7 million from Marathon Petroleum for the Ascension JV and $27.9 million from ENLC to reimburse us for costs incurred related to EnLink Oklahoma T.O.

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the nine months ended September 30, 2016 and 2015 were as follows (in millions):

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Common units	$ 387.0	$ 310.0
General partner interest (including incentive distribution rights)	43.7	28.9
Distributions to non-controlling interests (1)	5.6	66.5
Distributions to Devon for net assets acquired (2)	—	171.0

(1) Represents distributions to ENLC relating to ENLC's prior ownership in EnLink Midstream Holdings, LP during 2015, distributions to redeem the non-controlling interest in one of the E2 entities and ENLC's ownership of EnLink Oklahoma T.O. during 2016.
(2) Represents distributions to Devon relating to the VEX assets.

We received contributions from Devon related to the reimbursement of employee costs of $1.4 million and $2.2 million for the nine months ended September 30, 2016 and 2015, respectively. For the nine months ended September 30, 2015, we also received a contribution from Devon of $26.6 million related to the VEX pipeline.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our credit facility. We borrow money under our credit facility to fund checks as they are presented. Changes in drafts payable for the nine months ended September 30, 2016 and 2015 were as follows (in millions):

	Nine Months Ended September 30,	
	2016	2015
Decrease in drafts payable	$ —	$ (12.6)

Uncertainties. We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs, resulting in damage to certain of our facilities. We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, LLC (“Texas Brine”), the operator of a failed cavern in the area, and its insurers seeking recovery for these losses. We have also sued Occidental Chemical Company and Legacy Vulcan Corp. f/k/a Vulcan Materials Company, two Chlor-Alkali plant operators that participated in Texas Brine’s operational decisions regarding mining the failed cavern. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and have also sued our insurers. In August 2014, we received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

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

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, 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 2016 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

	2016
Growth Capital Expenditures	
Texas segment	$ 70 - 90
Louisiana segment	5 - 15
Oklahoma segment	110 - 135
Crude and Condensate segment	50 - 60
Corporate segment	0 - 0
Total	$ 235 - 300
Maintenance Capital Expenditures	$ 10.0

Our primary capital projects for 2016 include construction by the Delaware Basin JV of the Lobo II plant and gathering system in our Texas segment, commencing construction of our Marathon joint venture NGL pipeline in our Louisiana segment and developing our EnLink Oklahoma T.O. assets in our Oklahoma segment. See "Recent Developments" for further details.

We expect to fund the remaining growth capital expenditures from the proceeds of borrowing under our credit facility discussed below and proceeds from other debt and equity sources, including our Delaware Basin JV. We expect to fund our remaining 2016 maintenance capital expenditures from operating cash flows. In 2016, 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 September 30, 2016.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2016 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2016	2017	2018	2019	2020	Thereafter
Long-term debt obligations	$3,162.5	$ —	$ —	$ —	$400.0	$ —	$2,762.5
Credit facility	75.0	—	—	—	—	75.0	—
Interest payable on fixed long-term debt obligations	2,026.0	60.0	144.3	144.3	138.9	133.5	1,405.0
Capital lease obligations	11.6	1.0	4.5	2.9	1.5	1.7	—
Operating lease obligations	128.4	4.7	16.2	15.4	10.9	8.6	72.6
Purchase obligations	26.2	26.2	—	—	—	—	—
Delivery contract obligation	49.3	4.5	17.9	17.9	9.0	—	—
Pipeline capacity and deficiency agreements (1)	98.2	3.3	13.7	15.3	11.3	8.1	46.5
Inactive easement commitment (2)	10.0	—	—	—	—	—	10.0
Installment payable obligations (3)	500.0	—	250.0	250.0	—	—	—
Total contractual obligations	$6,087.2	$ 99.7	$446.6	$445.8	$571.6	$226.9	$4,296.6

(1) Consists of pipeline capacity payments for firm transportation and deficiency agreements to secure take-away capacity for our supply contracts. Amounts do not take into consideration costs passed back to customers.
(2) Amounts related to inactive easements paid as utilized by us with balance due at end of 10 years if not utilized.
(3) Amounts relate to our partial consideration of the Tall Oak acquisition with balances due on January 7, 2017 and 2018.

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

The interest payable under our credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time. However, given the same borrowing amount and rates in effect at September 30, 2016, the cash obligation for interest expense on our credit facility would be approximately $1.7 million per year or approximately $0.4 million for the remainder of 2016.

Our contractual cash obligations for the remainder of 2016 and 2017 are expected to be funded from cash flows generated from our operations, with the exception of our $250 million installment payable obligation due January 7, 2017 related to the acquisition of the EnLink Oklahoma T.O. assets. We expect to fund payment of this installment payable obligation from the proceeds of borrowings under our credit facility, proceeds from the issuance of equity, proceeds from the sale of certain assets or any combination of these alternatives.

Indebtedness

As of September 30, 2016 and December 31, 2015, long-term debt consisted of the following (in millions):

	September 30, 2016			December 31, 2015		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Partnership credit facility, due 2020 (1)	$ 75.0	$ —	$ 75.0	$ 414.0	$ —	$ 414.0
2.70% Senior unsecured notes due 2019	400.0	(0.3)	399.7	400.0	(0.4)	399.6
7.125% Senior unsecured notes due 2022	162.5	16.7	179.2	162.5	18.9	181.4
4.40% Senior unsecured notes due 2024	550.0	2.6	552.6	550.0	2.9	552.9
4.15% Senior unsecured notes due 2025	750.0	(1.1)	748.9	750.0	(1.2)	748.8
4.85% Senior unsecured notes due 2026	500.0	(0.7)	499.3	—	—	—
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	(6.7)	443.3	450.0	(6.9)	443.1
Other debt	—	—	—	0.2	—	0.2
Debt classified as long-term	$ 3,237.5	$ 10.3	$ 3,247.8	$ 3,076.7	$ 13.1	$ 3,089.8
Debt issuance cost (2)			(25.0)			(23.0)
Long-term debt, net of unamortized issuance cost			$ 3,222.8			$ 3,066.8

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective Interest rate was 2.2% at September 30, 2016 and 1.8% at December 31, 2015, respectively.
(2) Net of amortization of $7.3 million and $4.7 million at September 30, 2016 and December 31, 2015, respectively.

Credit Facility. As of September 30, 2016, there were $11.0 million in outstanding letters of credit and $75.0 million in outstanding borrowings under our credit facility, leaving approximately $1.4 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

See Note 6 to the condensed consolidated financial statements titled "Long-Term Debt" for further details.

Adopted Accounting Standards

In January 2016, we adopted Accounting Standards Update ("ASU") 2015-03,*Interest - Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs*. The update requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability and requires retrospective application. The application of this new accounting guidance resulted in the reclassification of $23.0 million of debt issuance costs from "Other Assets, Net" to "Long-term debt" in our accompanying Condensed Consolidated Balance Sheet as of December 31, 2015.

In January 2016, we adopted ASU 2015-17, *Balance Sheet Classification of Deferred Taxes* on a prospective basis. This new standard required that deferred tax assets and liabilities be classified as noncurrent in our Condensed Consolidated Balance Sheet as of March 31, 2016.

In January 2016, we adopted ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*, which eliminates the requirement for an acquirer to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated.

In January 2016, we adopted ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis.* The update provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporations and securitization structures, should be consolidated. The update is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. This update had no impact on our condensed consolidated financial statements or related disclosures.

In January 2016, we adopted ASU 2015-06, *Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions (a Consensus of the FASB Emerging Issues Task Force)* ("ASU 2015-06"), which requires a master limited partnership (MLP) to allocate earnings (losses) of a transferred business entirely to the general partner when computing earnings per unit (EPU) for periods before the dropdown transaction occurred. The EPU that the limited partners previously reported would not change as a result of the dropdown transaction. ASU 2015-06 also requires an MLP to disclose the effects of the dropdown transaction on EPU for the periods before and after the dropdown transaction occurred. ASU 2015-06 is effective for the fiscal years beginning after December 15, 2015, and interim periods within those annual periods. ASU 2015-06 requires retrospective application and early adoption is permitted. The update is effective for us beginning on January 1, 2016 and had no impact on our condensed consolidated financial statements and related disclosures.

In August 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-15, *Statement of Cash Flows (Topic 230) – Classification of Certain Cash Receipts and Cash Payments* ("ASU 2016-15"). ASU 2016-15 addresses the classification and presentation of certain cash receipts and cash payments related to debt prepayment or debt extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, and other specific cash flow issues. ASU 2016-15 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and should be applied using a retrospective transition method to each period presented. Early application is permitted, including adoption in an interim period. In September 2016, we elected to early adopt ASU 2016-15 effective January 1, 2016. The adoption did not have an impact on our condensed consolidated financial statements or related disclosures.

Accounting Standards to be Adopted in Future Periods

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting, which amends ASC Topic 718, Compensation – Stock Compensation* ("ASU 2016-09"). First, the new standard will require all of the tax effects related to share-based payments at settlement (or expiration) to be recorded through the income statement, and is required to be applied prospectively. Second, the new standard also allows entities to withhold taxes of an amount up to the employees' maximum individual tax rate in the relevant jurisdiction without resulting in liability classification of the award, and is required to be adopted using a modified retrospective approach. Third, under the ASU, forfeitures can be estimated, as currently required, or recognized when they occur. If elected, the change to recognize forfeitures when they occur must be adopted using a modified retrospective approach. ASU 2016-09 is effective for annual reporting periods beginning after December 15, 2016 including interim periods within those annual periods. Early adoption is permitted. We do not expect this standard to materially impact our condensed consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842) - Amendments to the FASB Accounting Standards Codification* ("ASU 2016-02"). 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. ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018 including interim periods within those annual periods. Early adoption is permitted, and is required to be adopted using a modified retrospective transition. We are currently evaluating the impact this standard will have on our condensed consolidated financial statements and related disclosures.

In May 2014, the FASB issued ASU 2014-09,*Revenue from Contracts with Customers* ("ASU 2014-09"). ASU 2014-09 will replace existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which we expect to be entitled in exchange for transferring goods or services to a customer. The new standard will also require significantly expanded disclosures regarding the qualitative and quantitative information of our nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and are to be applied retrospectively, with early application permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact the pronouncements will have on our condensed consolidated financial statements and related disclosures.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of federal securities laws. Statements included in this report which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. 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 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 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 Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement mandates in new legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the 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 position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. 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 June 2016, the CFTC proposed certain refinements to the previously proposed 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 significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements as summarized below. Approximately 89% of our processing margins are from fixed-fee based contracts for the nine months ended September 30, 2016.

1. *Processing margin contracts:* Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost 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.

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

3. *Percent of proceeds 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 percent of proceeds contracts, but they do decline during periods of low natural gas and liquids prices.

4. *Fixed-fee based contracts:* Under these contracts we have no direct commodity price exposure and are paid a fixed fee per unit of volume that is processed.

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 over-the-counter derivative financial instruments with only certain well-capitalized counterparties that 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 September 30, 2016 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 is as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume	We Pay	We Receive *	Fair Value Asset/(Liability) (In millions)
October 2016 - December 2016	Ethane	170 (MBbls)	$0.2776/gal	Index	$ (0.4)
October 2016 - September 2017	Propane	405 (MBbls)	Index	$0.6539/gal	1.8
October 2016 - September 2017	Normal Butane	109 (MBbls)	Index	$0.5984/gal	(0.5)
October 2016 - September 2017	Natural Gasoline	113 (MBbls)	Index	$0.9780/gal	(0.5)
October 2016 - September 2017	Natural Gas	17,438 (MMBtu/d)	Index	$2.9393/MMBtu*	(2.2)
October 2016	Condensate	50 (MBbls)	Index	$40.20/bbl*	(0.4)
					$ (2.2)

* 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 September 30, 2016, 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 $2.2 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $3.1 million in the net fair value of these contracts as of September 30, 2016.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate credit facility. At September 30, 2016, we had $75.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.8 million for the year.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2022, 2024, 2025, 2026, 2044 or 2045 as these are fixed-rate obligations. The estimated fair value of our senior unsecured notes was approximately $3,047.3 million as of September 30, 2016, based on market prices of similar debt at September 30, 2016. 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 approximately a $225.8 million decrease in fair value of our senior unsecured notes at September 30, 2016.

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 (September 30, 2016), 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

There has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2016 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.

For a discussion of certain litigation and similar proceedings, please refer to Note 13, “Commitments and Contingencies,” of the Notes to Condensed Consolidated Financial Statements contained in Part I of this Quarterly Report on Form 10-Q, which is incorporated by reference herein.

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 fiscal year ended December 31, 2015.

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):

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, 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).
3.4		—	Eighth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
3.5		—	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).
3.6		—	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).
3.7		—	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).
3.8		—	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).
4.1		—	Indenture, dated as of March 19, 2014, by and among EnLink Midstream Partners, LP, Subsidiary Guarantors, and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.2		—	Fourth Supplemental Indenture, dated as of July 14, 2016, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated July 11, 2016, filed with the Commission on July 14, 2016, file No. 001-36340).
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 September 30, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015, (ii) Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2016 and 2015, (iii) Consolidated Statements of Changes in Partners' Equity for the nine months ended September 30, 2016, (iv) Consolidated Statements of Cash Flows for the nine months ended September 30, 2016 and 2015, and (v) the Notes to Condensed Consolidated Financial Statements.

* Filed herewith.

** Pursuant to Item 601(b)(2) of Regulation S-K, the Registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

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/ MICHAEL J. GARBERDING
Michael J. Garberding
President and Chief Financial Officer

November 2, 2016

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, Chief Executive Officer of EnLink Midstream GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q 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: November 2, 2016

/s/ BARRY E. DAVIS
BARRY E. DAVIS,
Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, President and Chief Financial Officer of EnLink Midstream GP, LLC, the general partner of the registrant, 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: November 2, 2016

/s/ MICHAEL J. GARBERDING
MICHAEL J. GARBERDING,
President and Chief Financial Officer
(principal financial and accounting officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of EnLink Midstream Partners, LP (the "Registrant") on Form 10-Q of EnLink Midstream Partners, LP for the quarter ended September 30, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of EnLink Midstream GP, LLC, and Michael J. Garberding, 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: November 2, 2016	/s/ BARRY E. DAVIS Barry E. Davis *Chief Executive Officer*
Date: November 2, 2016	/s/ MICHAEL J. GARBERDING Michael J. Garberding *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.