EnLink Midstream, LLC
Form 10-Q
November 02, 2016
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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: 001-36336

ENLINK MIDSTREAM, LLC

(Exact name of registrant as specified in its charter)

Delaware 46-4108528

(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 180,048,704 common units outstanding.

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ENLINK MIDSTREAM, LLC

Condensed Consolidated Balance Sheets

	September 30, 2016	December 31, 2015
	(unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 60.1	$ 18.0
Accounts receivable:		
Trade, net of allowance for bad debt of $0.8 and $0.3, respectively	47.8	37.5
Accrued revenue and other	311.8	268.8
Related party	76.7	110.8
Fair value of derivative assets	4.3	16.8
Natural gas and NGLs inventory, prepaid expenses and other	39.5	41.8
Total current assets	540.2	493.7
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	1,542.2	2,413.9
Investment in unconsolidated affiliates	266.4	274.3
Other assets, net	2.4	2.7
Total assets	$ 10,197.2	$ 9,541.3
LIABILITIES AND MEMBERS’ 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	196.3	174.8
Total current liabilities	762.9	432.4
Long-term debt	3,245.2	3,066.0
Fair value of derivative liabilities	—	0.1
Asset retirement obligations	13.4	12.9
Other long-term liabilities	49.8	65.9
Installment payable, net of discount of $32.8	217.2	—
Deferred tax liability	542.8	532.1
Redeemable non-controlling interest	6.2	7.0
Members’ equity:		
	1,926.0	2,285.7

Members' equity (180,048,704 and 164,242,160 units issued and outstanding at September 30, 2016 and December 31, 2015, respectively)		
Non-controlling interest	3,433.7	3,139.2
Total members' equity	5,359.7	5,424.9
Commitments and contingencies (Note 15)		
Total liabilities and members' equity	$ 10,197.2	$ 9,541.3

See accompanying notes to condensed consolidated financial statements.

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ENLINK MIDSTREAM, LLC

Condensed Consolidated Statements of Operations

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	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(Unaudited) (In millions, except per unit amounts)			
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)	29.3	34.8	94.7	105.6
(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	873.3	799.2
Total operating costs and expenses	1,038.7	1,902.4	3,741.2	3,997.1
Operating income (loss)	65.9	(731.8)	(713.7)	(611.5)
Other income (expense):				
Interest expense, net of interest income	(48.4)	(30.4)	(138.9)	(72.1)
Income (loss) from unconsolidated affiliates	1.1	6.4	(0.5)	16.1
Other income	0.1	0.1	0.1	0.6
Total other expense	(47.2)	(23.9)	(139.3)	(55.4)
Income (loss) before non-controlling interest and income taxes	18.7	(755.7)	(853.0)	(666.9)
Income tax provision	(7.6)	(0.2)	(6.0)	(21.1)
Net income (loss)	11.1	(755.9)	(859.0)	(688.0)
Net income (loss) attributable to the non-controlling interest	10.4	(562.5)	(402.9)	(526.1)
Net income (loss) attributable to EnLink Midstream, LLC	$ 0.7	$ (193.4)	$ (456.1)	$ (161.9)
Devon investment interest in net income	$ —	$ —	$ —	$ 0.7
EnLink Midstream, LLC interest in net income (loss)	$ 0.7	$ (193.4)	$ (456.1)	$ (162.6)
Net income (loss) attributable to EnLink Midstream, LLC per unit:				
Basic common unit	$ —	$ (1.18)	$ (2.54)	$ (0.99)
Diluted common unit	$ —	$ (1.18)	$ (2.54)	$ (0.99)

(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 million and $0.3 million for the three and nine months ended September 30, 2015, respectively.

See accompanying notes to condensed consolidated financial statements.

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ENLINK MIDSTREAM, LLC

Consolidated Statement of Changes in Members' Equity

Nine Months Ended September 30, 2016

	Common Units		Non-Controlling Interest		Redeemable Non-controlling Interest (Temporary Equity)
	$	Units	$	Total	$
Balance, December 31, 2015	$ 2,285.7	164.2	$ 3,139.2	$ 5,424.9	$ 7.0
Unit-based compensation	11.2	—	11.3	22.5	—
Issuance of common units by the Partnership	—	—	110.6	110.6	—
Issuance of Preferred Units by the Partnership	—	—	724.1	724.1	—
Issuance of common units	214.9	15.6	—	214.9	—
Conversion of restricted units for common, net of units withheld for taxes	(1.2)	0.2	—	(1.2)	—
Non-controlling partner's impact of conversion of restricted units	—	—	(1.2)	(1.2)	—
Change in equity due to issuance of units by the Partnership	10.5	—	(16.8)	(6.3)	—
Non-controlling interest distributions	—	—	(283.5)	(283.5)	—
Non-controlling interest contribution	—	—	151.5	151.5	—
Distributions to members	(139.0)	—	—	(139.0)	—
Distributions to redeemable non-controlling interest	—	—	—	—	(0.8)
Contribution from Devon to the Partnership	—	—	1.4	1.4	—
Net loss	(456.1)	—	(402.9)	(859.0)	—
Balance, September 30, 2016	$ 1,926.0	180.0	$ 3,433.7	$ 5,359.7	$ 6.2

See accompanying notes to condensed consolidated financial statements.

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ENLINK MIDSTREAM, LLC

Consolidated Statements of Cash Flows

	Nine Months Ended September 30,	
	2016	2015
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net loss	$ (859.0)	$ (688.0)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Impairments	873.3	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
Deferred tax expense	4.4	18.2
Non-cash unit-based compensation	22.5	28.9
(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	2.9	2.4
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	(17.9)	124.1
Natural gas and NGLs inventory, prepaid expenses and other	11.9	(28.6)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	49.4	(60.5)
Net cash provided by operating activities	512.5	491.6
Cash flows from investing activities, net of assets acquired and liabilities assumed:		
Additions to property and equipment	(423.7)	(450.3)
Acquisition of business, net of cash acquired	(791.5)	(330.6)
Proceeds from insurance settlement	0.3	—
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	(1,203.6)	(774.3)
Cash flows from financing activities:		
Proceeds from borrowings	1,667.7	2,604.4
Payments on borrowings	(1,484.5)	(1,773.2)
Payments on capital lease obligations	(3.2)	(2.5)
Decrease in drafts payable	—	(12.6)
Debt financing costs	(4.7)	(9.5)
Mandatorily redeemable non-controlling interest	(4.0)	—
Conversion of restricted units, net of units withheld for taxes	(1.2)	(2.8)

Conversion of Partnership's restricted units, net of units withheld for taxes	(1.2)	(2.5)
Proceeds from issuance of Partnership's common units	110.6	12.9
Distributions to non-controlling partners	(284.3)	(266.8)
Distribution to members	(139.0)	(120.6)
Contribution from Devon	1.4	28.8
Distributions to Devon for net assets acquired	—	(171.0)
Proceeds from issuance of Partnership Preferred Units	724.1	—
Contributions by non-controlling interest	151.5	12.2
Net cash provided by financing activities	733.2	296.8
Net increase in cash and cash equivalents	42.1	14.1
Cash and cash equivalents, beginning of period	18.0	68.4
Cash and cash equivalents, end of period	$ 60.1	$ 82.5
Cash paid for interest	$ 71.2	$ 46.0
Cash paid (refund) for income taxes	$ (5.6)	$ 13.7

See accompanying notes to condensed consolidated financial statements.

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ENLINK MIDSTREAM, LLC

Notes to Condensed Consolidated Financial Statements

September 30, 2016

(Unaudited)

(1) General

In this report, the terms “Company” or “Registrant” as well as the terms “ENLC,” “our,” “we,” and “us,” or like terms, are sometimes used as references to EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to “EnLink Midstream Partners, LP,” the “Partnership,” “ENLK” or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, LP 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, LLC is a Delaware limited liability company formed in October 2013. The Company’s common units are traded on the New York Stock Exchange under the symbol “ENLC.”

Our assets consist of equity interests in the Partnership and EnLink Oklahoma T.O. The Partnership is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Oklahoma T.O. is a partnership held by us and the Partnership, and is engaged in the gathering and processing of natural gas. As of September 30, 2016, our interests in the Partnership and EnLink Oklahoma T.O. consist of the following:

88,528,451 common units representing an aggregate 22.5% limited partner interest in the Partnership;

100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of the Partnership (the “General Partner”), which owns a 0.4% general partner interest and all of the incentive distribution rights in the Partnership; and

16% limited partner interest in EnLink Oklahoma T.O.

(b)Nature of Business

The Partnership primarily focuses on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing to producers of natural gas, natural gas liquids, crude oil and condensate. The Partnership connects the wells of producers in its market areas to its gathering systems, processes natural gas to remove NGLs, fractionates NGLs into purity products and markets those products for a fee, transports natural gas and ultimately provides natural gas to a variety of markets. The Partnership purchases natural gas from natural gas producers and other supply sources and sells that natural gas to utilities, industrial consumers, other marketers and pipelines. The Partnership operates processing plants that process gas transported to the plants by major interstate pipelines or from its own gathering systems under a variety of fee-based arrangements. The Partnership provides 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. The Partnership also has crude oil and condensate terminal facilities that provide access for crude oil and condensate producers to premium markets. The Partnership’s 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. The Partnership’s transmission pipelines primarily receive natural gas from its gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. The Partnership also has transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants to its fractionators in south Louisiana. The Partnership’s 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. The Partnership’s processing plants remove NGLs and CO_2 from a natural gas stream and its fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

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(c)Consolidation of the Partnership

In January 2016, we adopted Accounting Standards Updates ("ASU") 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU 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. Due to ENLC's ownership of the General Partner, the Partnership is considered a variable interest entity as the limited partners lack the ability to exercise kick-out rights over the General Partner and do not have substantive participating rights. Further, ENLC, including the consideration of the Incentive Distribution Rights, is considered the primary beneficiary as it has the power to direct the activities that most significantly impact the Partnership's economic performance. The adoption of this standard has no impact on our consolidated financial statements as we will continue to consolidate the Partnership.

(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, the Partnership acquired assets from Devon through drop down transactions. Due to our control of the Partnership through our ownership and control of the General Partner and Devon's control of us through its ownership of our managing member, the acquisition from Devon was considered a transfer of net assets between entities under common control. As such, the Company was required to recast its 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 the Partnership's acquisition of the assets from Devon have been prepared from Devon's historical cost-basis accounts for the acquired assets and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the acquired assets during the periods reported. Net income attributable to the assets acquired from Devon for periods prior to the Partnership's acquisition is allocated to "Devon investment interest in net income" on the Company's Condensed Consolidated Statements of Operations.

(b)Adopted Accounting Standards

In January 2016, we adopted 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 $23.8 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 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-

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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 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 the Partnership expects 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 the Partnership’s 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, the Partnership 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.

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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

The Partnership 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 the Partnership’s Texas segment and is non-deductible for tax purposes.

Deadwood Acquisition

Prior to November 2015, the Partnership co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation (“Apache”). On November 16, 2015, the Partnership 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 the Partnership acquired a 16% and 84% 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 the Partnership 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 Partnership’s 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 the Partnership, 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 us and approximately $22.2 million in cash paid by us. The transaction was accounted for using the acquisition method.

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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	$ 805.8
Issuance of common units	214.9
The Partnership's total installment payable, net of discount of $79.1 million assuming payments are made on January 7, 2017 and 2018	420.9
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
Pro forma total revenues	$ 1,205.9	$ 3,556.8
Pro forma net loss	$ (775.1)	$ (743.6)
Pro forma net loss attributable to EnLink Midstream, LLC	$ (199.0)	$ (176.1)
Pro forma net loss per common unit:		

Basic	$ (1.11)	$ (0.98)
Diluted	$ (1.11)	$ (0.98)

(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 and the Partnership’s 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 and the Partnership perform our goodwill assessments at the reporting unit level for all reporting units. The Partnership uses a discounted cash flow analysis to perform the assessments for the Texas and Crude and Condensate reporting units. We use a market approach to perform the assessment for our Corporate reporting unit. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, control premium and estimated future cash flows including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, the Partnership incorporates 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 and the Partnership determined that the estimated fair values of the Partnership’s Texas and Crude and Condensate reporting units and our Corporate reporting unit were less than their respective carrying amounts. At the Partnership’s Texas and Crude and Condensate reporting units, this is primarily related to increases in the discount rate subsequent to year-end. For our Corporate reporting unit, this is due primarily to a further decline in our unit price subsequent to year-end. The second step of the goodwill impairment test at the Partnership 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 the Texas, Crude and Condensate, and Corporate reporting units in the amount of $873.3 million was recognized for the three months ended March 31, 2016, which is included in the nine months ended September 30, 2016 impairments line item in the Condensed Consolidated Statements of Operations.

We and the Partnership concluded that the fair value of goodwill of the 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 and the Partnership’s respective 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 and the Partnership’s assumptions and estimates, or assumptions and estimates change due to new information, we and the Partnership 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 values of our Corporate reporting unit and the Partnership’s Texas reporting unit may be impacted in the future by a further decline in our unit price or the Partnership’s unit price or a continuing prolonged period of lower commodity prices which may adversely affect the Partnership’s estimate of future cash flows all of which could result in future goodwill impairment charges.

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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	$ 1,426.9	$ 2,413.9
Impairment	(473.1)	—	—	(93.2)	(307.0)	(873.3)
Acquisition adjustment	1.6	—	—	—	—	1.6
Balance, end of period	$ 232.0	$ —	$ 190.3	$ —	$ 1,119.9	$ 1,542.2

Intangible Assets

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

The following table represents the Partnership's 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 the Partnership's 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

The Partnership engages 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 the Partnership. Devon accounted for 18.9% and 19.4% of the Partnership's 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. The Partnership 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, the Partnership 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.

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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
Company credit facility, due 2019 (2)	23.1	—	23.1	—	—	—
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
	450.0	(6.7)	443.3	450.0	(6.9)	443.1

5.05% Senior unsecured notes due 2045						
Other debt	—	—	—	0.2	—	0.2
Debt classified as long-term	$ 3,260.6	$ 10.3	$ 3,270.9	$ 3,076.7	$ 13.1	$ 3,089.8
Debt issuance cost (3)			(25.7)			(23.8)
Long-term debt, net of unamortized issuance cost			$ 3,245.2			$ 3,066.0

(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) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.0% at September 30, 2016.
(3) Net of amortization of $8.0 million at September 30, 2016 and $5.1 million at December 31, 2015.

Company Credit Facility

The Company has a $250.0 million revolving credit facility, which includes a $125.0 million letter of credit subfacility (the “credit facility”). Our obligations under the credit facility are guaranteed by two of our wholly-owned subsidiaries and secured by first priority liens on (i) 88,528,451 Partnership common units and the 100% membership interest in the General Partner indirectly held by us, (ii) the 100% equity interest in each of our wholly-owned subsidiaries held by us and (iii) any additional equity interests subsequently pledged as collateral under the credit facility.

The credit facility will mature on March 7, 2019. The credit facility contains certain financial, operational and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter, and include (i) maintaining a maximum consolidated leverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated funded indebtedness to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) of 4.00 to 1.00, provided that the maximum consolidated leverage ratio is 4.50 to 1.00 during an acquisition period (as defined in the credit facility) and (ii) maintaining a minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed

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as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) of 2.50 to 1.00 at all times unless an investment grade event (as defined in the credit facility) occurs.

Borrowings under the credit facility bear interest, at our option, at either the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.5%, 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 leverage ratio. Upon breach by us of certain covenants governing the credit facility, amounts outstanding under the credit facility, if any, may become due and payable immediately and the liens securing the credit facility could be foreclosed upon.

As of September 30, 2016 there was $23.1 million in outstanding borrowings under the credit facility, leaving approximately $226.9 million available for future borrowing based on the borrowing capacity of $250.0 million. The Company expects to be in compliance with all credit facility covenants for at least the next twelve months.

Partnership Credit Facility

The Partnership has a $1.5 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the "Partnership credit facility") that matures on March 6, 2020. Under the Partnership credit facility, the Partnership is permitted to, (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under the Partnership 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 the Partnership credit facility by one year on each occasion. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA may be increased to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

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

As of September 30, 2016, there were $11.0 million in outstanding letters of credit and $75.0 million in outstanding borrowings under the Partnership's 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 the Partnership credit facility are described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in the Company's Annual Report on Form 10-K for the year ended December 31, 2015. The Partnership expects 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, the Partnership issued $500.0 million in aggregate principal amount of the Partnership’s 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 the Partnership’s revolving credit facility and for general partnership purposes.

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(7) Income Taxes

Income taxes included in the condensed consolidated financial statements were as follows for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)		(in millions)	
ENLC income tax expense	$ 7.6	$ 0.2	$ 6.0	$ 21.1
Total income tax expense	$ 7.6	$ 0.2	$ 6.0	$ 21.1

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in millions)		(in millions)	
Tax expense (benefit) at statutory federal rate (35%)	$ 2.0	$ (67.6)	$ (158.0)	$ (49.5)
State income taxes expense (benefit), net of federal tax benefit	3.1	(4.8)	(11.8)	(3.5)
Income tax expense from partnership	2.6	0.6	1.3	1.7
Non-deductible expense related to asset impairment	(0.1)	72.3	173.8	72.3
Other	—	(0.3)	0.7	0.1
Total income tax expense	$ 7.6	$ 0.2	$ 6.0	$ 21.1

(8) Certain Provisions of the Partnership Agreement

(a)Issuance of Common Units

In November 2014, the Partnership entered into an Equity Distribution Agreement (the “BMO EDA”) with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the “Sales Agents”) to sell up to $350.0 million in aggregate gross sales of the Partnership’s common units 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, the Partnership 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). The Partnership 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, the Partnership 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 the Partnership’s 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 the 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 converted into common units on a one-for-one basis on May 13, 2016.

(c)Preferred Units

In January 2016, the Partnership issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units (“Preferred Units”) representing the Partnership’s 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

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fund the Partnership's 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 the Partnership's 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 the Partnership's 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 the General Partner or our managing member, 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 11, 2016.

(d)Distributions

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

Under the quarterly incentive distribution provisions, generally the Partnership's General Partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit.

A summary of the Partnership's 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
2016			
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)Allocation of Partnership Income

Net income is allocated to the General Partner in an amount equal to its incentive distributions as described in (d) above. The 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 the Partnership's net income adjusted for ENLC's unit-based compensation specifically allocated to the General Partner. The net income

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allocated to the General Partner is as follows for the three and nine months ended September 30, 2016 and 2015 (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

(9) Earnings per Unit and Dilution Computations

As required under FASB ASC 260-10-45-61A, unvested unit-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 the drop down interests acquired during 2015 from Devon for periods prior to acquisition is not allocated for purposes of calculating net income (loss) per common unit as they were fully assigned to the general partner interest. The following table reflects the computation of basic and diluted earnings per unit for the three and nine months ended September 30, 2016 and 2015 (in millions, except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
EnLink Midstream, LLC interest in net income (loss)	$ 0.7	$ (193.4)	$ (456.1)	$ (162.6)
Distributed earnings allocated to:				
Common units (1) (2)	$ 45.9	$ 41.9	$ 137.4	$ 123.2
Unvested restricted units (1) (2)	0.6	0.3	1.6	0.9
Total distributed earnings	$ 46.5	$ 42.2	$ 139.0	$ 124.1
Undistributed loss allocated to:				
Common units	$ (45.1)	$ (233.9)	$ (588.3)	$ (284.7)
Unvested restricted units	(0.7)	(1.7)	(6.8)	(2.0)
Total undistributed loss	$ (45.8)	$ (235.6)	$ (595.1)	$ (286.7)
Net income (loss) allocated to:				
Common units	$ 0.8	$ (192.0)	$ (450.9)	$ (161.5)
Unvested restricted units	(0.1)	(1.4)	(5.2)	(1.1)
Total net income (loss)	$ 0.7	$ (193.4)	$ (456.1)	$ (162.6)
Basic and diluted net income (loss) per unit:				
Basic	$ —	$ (1.18)	$ (2.54)	$ (0.99)
Diluted	$ —	$ (1.18)	$ (2.54)	$ (0.99)

(1) Three months ended September 30, 2016 and 2015 represents a declared distribution of \$0.255 per unit payable November 14, 2016 and a distribution of \$0.255 per unit paid on November 13, 2015, respectively.
(2) Represents a declared distribution of \$0.255 per unit payable on November 14, 2016, and distributions paid of \$0.255 on August 12, 2016, May 12, 2016 and November 13, 2015, \$0.25 per unit on August 14, 2015 and \$0.245 per unit on May 15, 2015 for the nine months ended September 30, 2016 and 2015.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Basic and diluted earnings per unit:				
Weighted average common units outstanding	180.0	164.2	179.6	164.2
Diluted weighted average units outstanding:				
Weighted average basic common units outstanding	180.0	164.2	179.6	164.2
Dilutive effect of restricted incentive units issued	1.1	—	—	—
Total weighted average diluted common units outstanding	181.1	164.2	179.6	164.2

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.

(10) Asset Retirement Obligations

The schedule below summarizes the changes in the Partnership's 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.

(11) Investment in Unconsolidated Affiliates

The Partnership's 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.

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

	Gulf Coast Fractionators	Howard Energy Partners	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 the Partnership's 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

(12) Employee Incentive Plans

(a)Long-Term Incentive Plans

The Partnership accounts for unit-based compensation in accordance with FASB ASC 718, which requires that compensation related to all unit-based awards, including unit options, be recognized in the condensed consolidated financial statements. On April 7, 2016, the 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 the Partnership’s common units 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.

The Partnership and we 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 officers and employees of the Partnership is recorded by the Partnership since ENLC has no substantial or managed

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operating activities other than its interests in the Partnership 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	$ 5.8	$ 6.3	$ 17.7	$ 24.9
Cost of unit-based compensation charged to operating expense	1.6	1.0	4.8	4.0
Total amount charged to income	$ 7.4	$ 7.3	$ 22.5	$ 28.9
Interest of non-controlling partners in unit-based compensation	$ 2.7	$ 2.6	$ 8.3	$ 11.4
Amount of related income tax expense recognized in income	$ 1.7	$ 1.8	$ 5.4	$ 6.5

(b)EnLink Midstream Partners, LP Restricted Incentive Units

The Partnership's 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, the 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 the Partnership and the Company (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 the Partnership's common units and the designated peer group securities; (iii) an estimated ranking of the Partnership 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 the Partnership's 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 non-vested Partnership 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	
		Weighted Average

EnLink Midstream, LLC Restricted Incentive Units:	Number of Units	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.

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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 the Company'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.

(13) Derivatives

Commodity Swaps

The Partnership manages its exposure to fluctuation in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs. The Partnership does not designate transactions as cash flow or fair value hedges for hedge accounting treatment under FASB ASC 815. Therefore, changes in the fair value of the Partnership’s derivatives are recorded in

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revenue in the period incurred. In addition, the Partnership's risk management policy does not allow the Partnership to take speculative positions with its derivative contracts.

The Partnership commonly enters into index (float-for-float) or fixed-for-float swaps in order to mitigate its cash flow exposure to fluctuations in the future prices of natural gas, NGLs 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 the Partnership receives a percentage of liquids as a fee for processing third-party gas or where the Partnership receives 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 its business and (3) where the Partnership is 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 the Partnership's 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. The Partnership estimates the fair value of all of its 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 the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements ("ISDAs") that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform

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under existing swap contracts, the Partnership's 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

The Partnership entered into interest rate swaps during April and May 2015 in connection with the issuance of the 2025 Notes in May 2015. Additionally, the Partnership entered into interest rate swaps during July 2016 in connection with the issuance of the 2026 Notes in July 2016. The Partnership has 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

(14) 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.

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

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

	September 30, 2016	December 31, 2015
	Level 2	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 the Partnership's and/or the counterparty credit risk of the Partnership as required under FASB ASC 820.

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Fair Value of Financial Instruments

The Partnership has determined the estimated fair value of its 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 the Partnership 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	$ 3,245.2	$ 3,124.5	$ 3,066.0	$ 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 the Partnership's cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership had $75.0 million and $414.0 million in outstanding borrowings under its revolving credit facility as of September 30, 2016 and December 31, 2015, respectively. We had $23.1 million in outstanding borrowings under our credit facility as of September 30, 2016. As borrowings under either credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the applicable credit facility. As of September 30, 2016 and December 31, 2015, the Partnership had total borrowings under senior unsecured notes of $3.1 billion and $2.7 billion, 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.

(15) Commitments and Contingencies

(a)Severance and Change in Control Agreements

Certain members of management of the Partnership are parties to severance and change of control agreements with EnLink Midstream Operating, LP. 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 the 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 the General Partner or its affiliates or interfering with a client or customer of the 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, the Partnership must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on the Partnership's results of operations, financial condition or cash flows. In February 2016, a spill occurred at the Partnership's Kill Buck Station in the 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

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internally transitioned monitoring to their water quality division. The Partnership does 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 the Partnership's operational control of E2 Appalachian Compression, LLC in and preparation to commence operational control of E2 Ohio Compression, LLC, the Partnership 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"). The Partnership 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 have information concerning any fine or penalty that may be assessed, we do not believe any such fine or penalty will be material to the Partnerships' operations. On July 29, 2016, after concluding a multi-year internal environmental compliance assessment of the Partnership's Louisiana operations, the Partnership 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 the Partnership's assessment, which involved several of the Partnership's 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 the Partnership's assessment as well as noncompliance that was the subject of notices of potential violations and NOVs that the Partnership received from the LDEQ during the assessment time frame. The Partnership has taken the appropriate measures to resolve the instances of noncompliance, and will continue to work with the LDEQ with respect to the proposed Global Settlement. Additionally, although the spill that previously occurred in the Partnership's West Virginia operations in the third quarter of 2015 is still pending, the Partnership does not believe that any fine or penalty that may be issued will be material to its operations. Lastly, the Partnership continues 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

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

At times, the Partnership's subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and 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, the Partnership does not expect that awards in these matters will have a material adverse effect on its financial position, results of operations or cash flows.

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

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

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The Partnership owns and operates 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 the Partnership's facilities. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine Company, LLC ("Texas Brine"), the operator of a failed cavern in the area and its insurers, seeking recovery for these losses. The Partnership has 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. The Partnership also filed a claim with its insurers, which the Partnership's insurers denied. The Partnership disputed the denial and has also sued its insurers. In August 2014, the Partnership received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million but additional claims remain outstanding. The Partnership cannot give assurance that the Partnership will be able to fully recover its losses through insurance recovery or claims against responsible parties.

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

(16) Segment Information

Identification of the majority of the Company's operating segments is based principally upon geographic regions served. The Company's reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in north Texas, south Texas and the Permian Basin in west Texas ("Texas"), the pipelines and processing plants located in Louisiana and NGL assets located in south Louisiana ("Louisiana"), natural gas gathering and processing operations located throughout Oklahoma ("Oklahoma") and crude rail, truck, pipeline and barge facilities in west Texas, south Texas, Louisiana and Ohio River Valley ("Crude and Condensate"). Operating activity for intersegment eliminations is shown in the corporate segment. The Company's sales are derived from external domestic customers.

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

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Summarized financial information concerning the Company's 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	$ —	$ 1,119.9	$ 1,542.2
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	$ 1,426.9	$ 3,156.8
Capital expenditures	$ 29.0	$ 13.5	$ 19.7	$ 38.6	$ 3.9	$ 104.7

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	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)	$ (307.0)	$ (873.3)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ 1,119.9	$ 1,542.2
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	$ 1,426.9	$ 3,156.8
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	1,471.9	1,751.1

Total identifiable assets	$ 10,197.2	$ 9,541.3

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	(29.3)	(34.8)	(94.7)	(105.6)
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)	(873.3)	(799.2)
Operating income (loss)	$ 65.9	$ (731.8)	$ (713.7)	$ (611.5)

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(17) 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:		
Non-cash issuance of common units (1)	$ 214.9	$ —
Non-cash issuance of common units of Partnership (2)	—	180.0
Non-cash issuance of Class C Common Units of the Partnership (2)	—	180.0
Installment payable, net of discount of $79.1 million (3)	420.9	—

(1) For the nine months ended September 30, 2016, non-cash common units were issued as partial consideration for the Tall Oak acquisition. See Note 3 - Acquisitions for further discussion.
(2) For the nine months ended September 30, 2015, non-cash common units and Class C Common Units were issued by the Partnership as partial consideration for the Coronado acquisition.
(3) The Partnership 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.

(18) 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	$ 58.1	$ 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	57.6
Other current liabilities	$ 196.3	$ 174.8

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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 terms "Company" or "Registrant" as well as the terms "ENLC," "our," "we," and "us," or like terms, are sometimes used as references to EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP," the "Partnership," "ENLK" or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, LP and EnLink Oklahoma Gas Processing, ("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 liability company formed in October 2013. Our assets consist of equity interests in EnLink Midstream Partners, LP and EnLink Oklahoma T.O. EnLink Midstream Partners, LP is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Oklahoma T.O., a partnership owned by the Partnership and us, is engaged in the gathering and processing of natural gas. Our interests in EnLink Midstream Partners, LP and EnLink Oklahoma T.O. consist of the following as of September 30, 2016:

88,528,451 common units representing an aggregate 22.5% limited partner interest in the Partnership;

100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of the Partnership (the "General Partner"), which owns a 0.4% general partner interest and all of the incentive distribution rights in the Partnership; and

16% limited partner interest in EnLink Oklahoma T.O.

The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of the Partnership's business, or to provide for future distributions.

The incentive distribution rights in the Partnership entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

In January 2016, we adopted Accounting Standards Updates ("ASU") 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU 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. Due to ENLC's ownership of the General Partner, the Partnership is considered a variable interest entity as the limited partners lack the ability to exercise kick-out rights over the General Partner and do not have substantive participating rights. Further, ENLC is considered the primary beneficiary as it has the power to direct the activities that most significantly impact the Partnership's economic performance. The adoption of this standard has no impact on our consolidated financial statements as we will continue to consolidate the Partnership. Accordingly, the discussion of our financial position and results of operations in this “Management’s Discussion and Analysis of Financial Condition and Results of Operations” primarily reflects the operating activities and results of operations of the Partnership and EnLink Oklahoma T.O.

The Partnership primarily focuses 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. The Partnership’s midstream energy asset network includes approximately 11,000 miles of pipelines, 21 processing plants 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

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facilities, purchase and marketing capabilities, brine disposal wells, a crude oil trucking fleet and equity investments in certain private midstream companies. The Partnership manages and reports its activities primarily according to the nature of activity and geography. The Partnership has five reportable segments: (1) Texas, which includes the Partnership's natural gas gathering, processing and transmission activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes the Partnership's 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 the Partnership's natural gas pipelines, natural gas processing plants and NGL assets located in Louisiana; (4) Crude and Condensate, which includes the Partnership's Ohio River Valley ("ORV") crude oil, condensate and brine disposal activities in the Utica and Marcellus Shales, its ownership of E2 Appalachian Compression, LLC and its equity interests in E2 Energy Services, LLC and E2 Ohio Compression, LLC (collectively, "E2"), its crude oil operations in the Permian Basin and its 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 the Partnership's unconsolidated affiliate investments in Howard Energy Partners ("HEP") in the Eagle Ford Shale, its contractual right to the economic burdens and benefits associated with Devon's ownership interest in Gulf Coast Fractionators ("GCF") in south Texas and its general partnership property and expenses.

The Partnership manages its operations by focusing on gross operating margin because the Partnership's business is generally to gather, process, transport or market natural gas, NGLs, crude oil and condensate using its assets for a fee. The Partnership earns its fees through various contractual arrangements, which include stated fixed-fee contract arrangements or arrangements where the Partnership purchases and resells commodities in connection with providing the related service and earns a net margin as its fees. While the Partnership's transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. The Partnership defines 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 the Partnership's gross operating margin was derived from fee-based services with no direct commodity exposure for the nine months ended September 30, 2016. The Partnership reflects revenue as "Product sales" and "Midstream services" on the Condensed Consolidated Statements of Operations.

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

The Partnership generates revenues from eight primary sources:

- gathering and transporting natural gas and NGLs on the pipeline systems it owns;
- processing natural gas at its 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

The Partnership typically gathers or transports gas owned by others through its facilities for a fee. The Partnership also buys 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 transports and resells the natural gas at the same market index. The fixed discount difference to a market index represents the fee for using the Partnership's assets. The Partnership attempts to execute substantially all purchases and sales concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the fee it

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will receive for each natural gas transaction. The Partnership's gathering and transportation fee related to a percentage of the index price can be adversely affected by declines in the price of natural gas. The Partnership is also party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time, the supplies that it has under contract may decline due to reduced drilling or other causes, and the Partnership 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 the Partnership's purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

On occasion the Partnership has 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 it captures the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as its fee. Changes in the basis spread can increase or decrease margins or potentially result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its North Texas Pipeline and sells the gas into a different market area index. The Partnership realizes 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.

The Partnership typically transports and fractionates or stores NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. The Partnership also buys mixed NGLs from its suppliers at a fixed discount to market indices for the component NGLs with a deduction for its fractionation fee. The Partnership subsequently sells the fractionated NGL products based on the same index-based prices. The operating results of the Partnership's NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With the Partnership's fractionation business, it also has the opportunity for product upgrades for each of the discrete NGL products. The fees the Partnership earns on the product upgrade from this fractionation business are higher during periods with higher liquids prices.

The Partnership generally gathers or transports crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a fee. The Partnership also buys crude oil and condensate from a producer at a fixed discount to a market index, then transports and resells the crude oil and condensate at the same market index. The Partnership executes substantially all purchases and sales concurrently, thereby establishing the fee it will receive for each crude oil and condensate transaction.

The Partnership realizes gross operating margins from its 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 the Partnership's 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 the Partnership's 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.

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Recent Developments

Acquisition

Tall Oak. On January 7, 2016, we and the Partnership acquired a 16% and 84% 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 Partnership's 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 the Partnership, 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 of our common units issued directly by us and approximately $22.2 million in cash paid by us.

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.

The Partnership plans 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 is supported by long-term contracts.

Battle Ridge Plant. The Battle Ridge Plant, which provides us and the Partnership 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. The Partnership is constructing a new crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin that the Partnership refers 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 the Partnership's 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, the Partnership 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 the Partnership’s Midland Basin system, and key customers include Diamondback Energy, Inc., RSP Permian, Inc. and Concho Resources, Inc.

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Delaware Basin Joint Venture. On August 1, 2016, the Partnership formed a joint venture (the “Delaware Basin JV”) with an affiliate of NGP Natural Resources XI, L.P. (“NGP”) to operate and expand the Partnership’s 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 the Partnership and 49.9 percent by NGP. The Partnership 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 the Partnership at the formation of the joint venture to reimburse the Partnership for capital spent to date on existing assets and ongoing projects. In addition to the initial contributions, the Partnership and NGP contributed $23.4 million to the Delaware Basin JV in the third quarter of 2016. As part of this agreement, NGP granted the Partnership 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 third quarter 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. The Partnership has 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 the Partnership’s existing Riverside fractionation and terminal complex to Marathon Petroleum’s Garyville refinery located on the Mississippi River. This bolt-on project to the Partnership’s Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, the Partnership 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, the Partnership made contributions to HEP, primarily to fund the Partnership’s 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, the Partnership contributed $3.2 million and $45.0 million. Included in the Partnerships’ contributions for the nine months ended September 30, 2016 is the Partnership’s 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, the Partnership issued $500.0 million in aggregate principal amount of the Partnership's 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 the Partnership's revolving credit facility and for general partnership purposes.

Issuance of Partnership 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.

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For the nine months ended September 30, 2016, the Partnership 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). The Partnership 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 Partnership Preferred Units

On January 7, 2016, the Partnership issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing limited partner interests (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 the Partnership's 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 the Partnership's 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 the Partnership's 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 the General Partner or our managing member, 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

Cash Available for Distribution

We calculate cash available for distribution as distributions due to us from the Partnership and our interest in EnLink Oklahoma T.O. adjusted EBITDA (as defined herein) and our interest in Midstream Holdings adjusted EBITDA (as defined herein), less our share of maintenance capital attributable to our interest in EnLink T.O. and Midstream Holdings, our specific general and administrative costs as a separate public reporting entity, the interest costs associated with our debt and current taxes attributable to our earnings, plus our standalone impairment expense. ENLC's share of EnLink Oklahoma T.O. growth capital expenditures are funded by borrowings under ENLC's credit facility and not considered in determining ENLC's cash flow available for distribution. Cash available for distribution is a supplemental liquidity metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Cash available for distribution is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment.

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 connection, compression and processing assets up to their original operating capacity, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations.

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The GAAP measure most directly comparable to cash available for distribution is net income (loss). Cash available for distribution should not be considered as an alternative to GAAP net income (loss). Cash available for distribution is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Because cash available for distribution excludes some items that affect net income (loss) and is defined differently by different companies in our industry, our definition of cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following is a calculation of the Company's cash available for distribution (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Distribution declared by ENLK associated with (1):				
General partner interest	$ 0.5	$ 0.6	$ 1.6	$ 1.8
Incentive distribution rights	14.4	13.6	42.4	33.7
ENLK common units owned	34.6	33.4	103.6	70.0
Total share of ENLK distributions declared	$ 49.5	$ 47.6	$ 147.6	$ 105.5
Transferred interest EBITDA (2)	—	—	—	53.7
Adjusted EBITDA of EnLink Oklahoma T.O. (3)	2.9	—	5.9	—
Transaction costs (4)	—	—	0.6	—
Total cash available	$ 52.4	$ 47.6	$ 154.1	$ 159.2
Uses of cash:				
General and administrative expenses	(0.9)	(1.1)	(3.8)	(3.0)
Current income taxes (5)	—	1.2	—	—
Interest expense	(0.4)	(0.2)	(1.0)	(0.7)
Maintenance capital expenditures (6)	—	—	—	(4.0)
Total cash used	$ (1.3)	$ (0.1)	$ (4.8)	$ (7.7)
ENLC cash available for distribution	$ 51.1	$ 47.5	$ 149.3	$ 151.5

(1) Represents distributions to be paid to us on November 11, 2016 and distributions paid on August 11, 2016, May 12, 2016, November 12, 2015, August 14, 2015 and May 14, 2015.
(2) Represents our interest in EnLink Midstream Holdings, LP's ("Midstream Holdings") adjusted EBITDA, which was disbursed to ENLC by Midstream Holdings on a monthly basis prior to the transfer of all interests in Midstream Holdings to the Partnership in drop down transactions (the "EMH Drop Downs"). Midstream Holdings' adjusted EBITDA is defined 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.
(3) Represents our interest in EnLink Oklahoma T.O. adjusted EBITDA, which is disbursed to ENLC by EnLink Oklahoma T.O. on a monthly basis. EnLink Oklahoma T.O. adjusted EBITDA is defined as earnings before depreciation and amortization and provision for income taxes.
(4) Represents acquisition transaction costs attributable to the Company's 16% interest in EnLink Oklahoma T.O, which are considered growth capital expenditures as part of the cost of the assets acquired.
(5) Represents our stand-alone current tax expense.

(6) Represents our interest in Midstream Holdings' maintenance capital expenditures prior to the EMH Drop Downs which is netted against the monthly disbursement of Midstream Holdings' adjusted EBITDA per (2) above. There are no maintenance capital expenditures attributable to ENLC's share of EnLink Oklahoma T.O. during 2016. All of EnLink Oklahoma T.O. capital expenditures during 2016 are growth related which are not considered in determining cash flow available for distribution.

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The following table provides a reconciliation of ENLC net income (loss) to ENLC cash available for distribution (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income (loss) of ENLC	$ 11.1	$ (755.9)	$ (859.0)	$ (688.0)
Less: Net income (loss) attributable to ENLK	18.8	(754.9)	(536.6)	(665.5)
Net loss of ENLC excluding ENLK	$ (7.7)	$ (1.0)	$ (322.4)	$ (22.5)
ENLC's share of distributions from ENLK (1)	49.4	47.6	147.5	105.5
ENLC's interest in EnLink Oklahoma T.O. depreciation	3.6	—	10.4	—
ENLC deferred income tax (benefit) expense (2)	5.0	0.5	4.7	18.3
Maintenance capital expenditures (3)	—	—	—	(4.0)
Transferred interest EBITDA (4)	—	—	—	53.7
ENLC corporate goodwill impairment	—	—	307.0	—
Other items (5)	0.8	0.4	2.1	0.5
ENLC cash available for distribution	$ 51.1	$ 47.5	$ 149.3	$ 151.5

(1) Represents distributions declared by ENLK and to be paid to ENLC on November 11, 2016 and distributions paid by ENLK to ENLC on August 11, 2016, May 12, 2016, November 12, 2015, August 14, 2015 and May 14, 2015.
(2) Represents our stand-alone deferred taxes.
(3) There are no maintenance capital expenditures attributable to ENLC’s share of EnLink Oklahoma T.O. during 2016. All of EnLink Oklahoma T.O. capital expenditures during 2016 are growth related which are not considered in determining cash flow available for distribution. For the three and nine month periods ended September 30, 2015, the amounts represent ENLC’s interest in maintenance capital expenditures of Midstream Holdings prior to the EMH Drop Downs during the first half of 2015.
(4) Represents our interest in the adjusted EBITDA of Midstream Holdings prior to the EMH Drop Downs. Adjusted EBITDA of Midstream Holdings’ is defined as maintenance capital expenditures prior to the EMH Drop Downs netted against the monthly disbursement of Midstream Holdings’ adjusted EBITDA.
(5) Represents transaction costs attributable to our share of the acquisition of EnLink Oklahoma T.O. and other non-cash items not included in cash available for distributions.

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 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 operating costs that affect operating income (loss). 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.

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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
Operating income (loss)	$ 65.9	$ (731.8)	(713.7)	$ (611.5)
Add (deduct):				
Operating expenses	98.0	105.0	296.3	312.6
General and administrative expenses	29.3	34.8	94.7	105.6
Depreciation and amortization	126.2	98.4	373.0	289.1
(Gain) loss on disposition of assets	(3.0)	3.2	(2.9)	3.2
Impairments	—	799.2	873.3	799.2
Total gross operating margin	$ 316.4	$ 308.8	$ 920.7	$ 898.2

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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

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decrease was primarily attributable to an $8.7 million decrease in gross operating margin from the 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 the Louisiana segment's 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 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,

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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 $29.3 million for the three months ended September 30, 2016 compared to $34.8 million for the three months ended September 30, 2015, a decrease of $5.5 million, or 15.8%. The primary contributors to the decrease were as follows:

ur wages and salaries decreased $4.5 million due to decreases in bonus expense and severance expense;

ur rent expense increased $1.7 million related to new office leases, which commenced during 2016;

ur bad debt expense decreased $0.8 million;

ur transaction costs related to acquisitions decreased $0.7 million; and

ur 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 the Partnership recognized an impairment on goodwill of $576.1 million related to its Louisiana segment and an impairment on intangible assets in its Crude and Condensate segment of $223.1 million. For more information, see "Critical Accounting Policies-Impairment of Goodwill" below.

Interest Expense. Interest expense was $48.4 million for the three months ended September 30, 2016 compared to $30.4 million for the three months ended September 30, 2015, an increase of $18.0 million, or 59.2%. Of the increase, $6.0 million was attributable to an increase in average debt in 2016 compared to 2015, $1.4 million was attributable to a decrease in capitalized interest in 2016 compared to 2015 and $13.3 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 the Partnership’s 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
Partnership senior notes	$ 35.1	$ 30.0

Partnership credit facility	2.2	1.3
Credit facility	0.3	0.1
Capitalized interest	(1.3)	(2.7)
Cash settlements on interest rate swaps	(0.4)	—
Amortization of debt issue costs and net discounts (premium)	13.6	0.2
Mandatory redeemable non-controlling interest	—	1.3
Other	(1.1)	0.2
Total	$ 48.4	$ 30.4

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

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income from the Partnership's investment in HEP attributable to increased interest, depreciation and amortization expense resulting from acquisitions.

Income Tax Provision. Income tax expense was $7.6 million for the three months ended September 30, 2016 compared to income tax expense of $0.2 million for the three months ended September 30, 2015, an increase of $7.4 million. The increase in income tax expense was primarily attributable to an increase in taxable income between periods. See Note 7 to the condensed consolidated financial statements titled "Income Taxes" for further details.

Net Income (Loss) Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $10.4 million for the three months ended September 30, 2016 compared to a net loss of $562.5 million for the three months ended September 30, 2015, an increase of $572.9 million. This increase was due primarily to impairments at the Partnership during the three months ended September 30, 2015.

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 the 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, the Partnership's gross operating margin from the Cana gathering and processing assets increased by $6.7 million between periods due primarily to increased volumes combined with the expansion of 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 commodity swaps between periods.

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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 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 $94.7 million for the nine months ended September 30, 2016 compared to $105.6 million for the nine months ended September 30, 2015, a decrease of $10.9 million, or 10.3%. 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 $873.3 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 $74.1 million, or 9.2%. During March 2016, we recognized an impairment on goodwill of $566.3 million related to the Partnership's Texas and Crude and Condensate segments, and $307.0 million related to our Corporate segment. During September 2015 we recognized an impairment on goodwill of $576.1 million related to the Partnership's Louisiana segment and an impairment on intangible assets in the Partnership's Crude and Condensate segment of $223.1 million. For more information, see "Critical Accounting Policies-Impairment of Goodwill" below.

Interest Expense. Interest expense was $138.9 million for the nine months ended September 30, 2016 compared to $72.1 million for the nine months ended September 30, 2015, an increase of $66.8 million, or 92.6%. Of the increase, $23.3 million was attributable to an increase in average debt in 2016 compared to 2015, $39.6 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
Partnership senior notes	$ 95.1	$ 75.9
Partnership credit facility	9.6	5.8
Credit facility	0.7	0.4
Capitalized interest	(5.5)	(5.6)
Amortization of debt issue costs and net discounts (premium)	39.8	0.2
Cash settlements on interest rate swaps	(0.4)	(3.6)
Mandatory redeemable non-controlling interest	0.3	(2.0)
Other	(0.7)	1.0
Total	$ 138.9	$ 72.1

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 the Partnership's 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 the Partnership's HEP investment and is primarily attributable to increased interest, depreciation, and amortization expense resulting from acquisitions.

Income Tax Provision. Income tax expense was $6.0 million for the nine months ended September 30, 2016 compared to income tax expense of $21.1 million for the nine months ended September 30, 2015, a decrease of $15.1 million. The decrease in income tax expense was primarily attributable to a decrease in taxable income between periods. Although we realized a net loss before income taxes of $853.0 million during the nine months ended September 30, 2016, we did not realize a larger tax benefit as substantially all of the loss was the result of a goodwill impairment recognized during the three months ended March 31, 2016, which is treated as a permanent difference for tax. See Note 7 to the condensed consolidated financial statements titled “Income Taxes” for further details.

Net Income (Loss) Attributable to Non-Controlling Interest. Net loss attributable to non-controlling interest was $402.9 million for the nine months ended September 30, 2016 compared to a net loss of $526.1 million for the nine

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months ended September 30, 2015, a decrease of $123.2 million. This decrease was due primarily to a decrease in impairments at the Partnership during 2016.

Critical Accounting Policies

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

Impairment of Goodwill. We conduct an 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 and the Partnership's 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 and the Partnership perform our goodwill assessments at the reporting unit level for all reporting units. The Partnership uses a discounted cash flow analysis to perform the assessments. We use a market approach to perform the assessment for our Corporate reporting unit. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, control premium and estimated future cash flows including volume and price forecasts and estimated operating expense and general and administrative costs. In estimating cash flows, the Partnership incorporates 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 and the Partnership determined that the estimated fair values of the Partnership's Texas and Crude and Condensate reporting units and our Corporate reporting unit were less than their respective carrying amounts. At the Partnership's Texas and Crude and Condensate reporting units, this was related primarily to increases in the discount rate subsequent to year-end. For our Corporate reporting unit, this was due primarily to a further decline in our unit price subsequent to year-end. The second step of the goodwill impairment test at the Partnership 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 the Texas, Crude and Condensate and Corporate reporting units in the amount of $873.3 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.

The Partnership concluded that the fair value of goodwill of the Partnership's 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 the Partnership's Texas reporting unit and our Corporate reporting unit are not substantially in excess of their carrying value. As of March 31, 2016, the fair value of the Partnership's Texas reporting unit and our Corporate 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 Partnership's Texas reporting unit and $1.1 billion allocated to our Corporate reporting unit.

Our and the Partnership's respective impairment determination 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 and the Partnership's assumptions and estimates, or assumptions and estimates change due to new information, we and the Partnership 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 values of our Corporate reporting unit and the Partnership's Texas reporting unit may be impacted in the future by a

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further decline in our unit price or the Partnership's unit price or a continuing prolonged period of lower commodity prices, which may adversely affect the Partnership's estimate of future cash flows all of which could result in future goodwill impairment charges.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $512.5 million for the nine months ended September 30, 2016 compared to $491.6 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 changes in working capital	$ 469.1	$ 456.6
Changes in working capital	43.4	35.0

The primary reason for the increase in operating cash flows before changes in working capital of $12.5 million from 2015 to 2016 relates to an increase in gross operating margin from the acquisition of Coronado, Matador, Deadwood and EnLink Oklahoma T.O. assets, which is partially offset by a decrease in gross operating margin in the Partnership's Crude and Condensate segment due to lower volumes and the termination of a customer contract during the second quarter of 2015. The change in working capital for 2016 related to fluctuations in trade receivable and payable balances is 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 $1,203.6 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
Acquisition of business	791.5	330.6
Proceeds from insurance settlement	(0.3)	—
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 Investing	$ 1,203.6	$ 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 the Partnership's 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 the Partnership's Texas and Oklahoma segments due to a decrease in activity.

Acquisition expenditures increased $460.9 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.

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During the nine months ended September 30, 2016, the Partnership contributed $45.0 million to its unconsolidated investment in HEP. Included in the Partnership’s contributions is the 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 $733.2 million and $296.8 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	2015
Net repayments on Partnership's credit facility	$ (339.2)	$ (62.1)
Net borrowings on Company's credit facility	23.1	—
Unsecured Partnership senior notes borrowings	499.3	893.3
Net repayments under capital lease obligations	(3.2)	(2.5)
Debt financing costs	(4.7)	(9.5)
Proceeds from issuance of Partnership common units	110.6	12.9
Proceeds from issuance of Partnership preferred units	724.1	—
Contributions by non-controlling interest	151.5	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 the Partnership at the formation of the joint venture to reimburse the Partnership for capital spent to date on existing assets and ongoing projects. In addition to NGP’s initial contribution, 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.

Distributions to unitholders and Devon 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	2015
Distributions to members	$ 139.0	$ 120.6
Distributions to non-controlling partners	284.3	266.8
Distributions to Devon for net assets acquired (1)	—	171.0

(1) Represents distributions to Devon relating to the VEX assets.

The Partnership received contributions from Devon of $1.4 million and $2.2 million for the nine months ended September 30, 2016 and 2015, respectively, which related to the reimbursement of employee costs. For the nine months ended September 30, 2015, the Partnership 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. The Partnership owns and operates 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 the Partnership's facilities. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine Company, LLC ("Texas Brine"), the operator of a failed cavern in the area and its insurers, seeking recovery for these

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losses. The Partnership has 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. The Partnership also filed a claim with its insurers, which the Partnership's insurers denied. The Partnership disputed the denial and has also sued its insurers. In August 2014, the Partnership received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. The Partnership cannot give assurance that the Partnership will be able to fully recover its losses through insurance recovery or claims against responsible parties.

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

Capital Requirements. The Partnership considers a number of factors in determining whether its capital expenditures are growth capital expenditures or maintenance capital expenditures. Growth capital expenditures generally include capital expenditures made for acquisitions or capital improvements that the Partnership expects will increase its 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 its 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 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 Partnership expects to fund its remaining 2016 capital expenditures, including capital contributions to its unconsolidated affiliate investments, 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

The Partnership's primary capital projects for 2016 include construction by the Delaware Basin JV of the JV's Lobo II plant and gathering system in its Texas segment, commencing construction of its Marathon joint venture NGL pipeline in its Louisiana segment, developing its EnLink Oklahoma T.O. assets in its Oklahoma segment. See "Recent

Developments” for further details.

The Partnership expects 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 its Delaware Basin JV. The Partnership expects to fund its 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. The Partnership’s ability to pay distributions to its unitholders, to fund planned capital expenditures and to make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in the industry, financial, business and other factors, some of which are beyond its control.

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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
Partnership's credit facility	75.0	—	—	—	—	75.0	—
Company credit facility	23.1	—	—	—	23.1	—	—
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	$ 6,110.3	$ 99.7	$ 446.6	$ 445.8	$ 594.7	$ 226.9	$ 4,296.6

(1)Consists of pipeline capacity payments for firm transportation and deficiency agreements to secure take-away capacity for the Partnership’s supply contracts. Amounts do not take into consideration costs passed back to customers.

(2)Amounts related to inactive easements paid as utilized by the Partnership with balance due at end of 10 years if not utilized.

(3)Amounts relate to the Partnership’s 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 the Partnership's 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 the Partnership's credit facility would be approximately $1.7 million per year or approximately $0.4 million for the remainder of 2016.

The interest payable under the Company's 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 the Company's credit facility would be approximately $0.7 million per year or approximately $0.2 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.

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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
Company credit facility, due 2019 (2)	23.1	—	23.1	—	—	—
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	$ 3,260.6	$ 10.3	$ 3,270.9	$ 3,076.7	$ 13.1	$ 3,089.8
Debt issuance cost (3)			(25.7)			(23.8)
Long-term debt, net of unamortized issuance cost			$ 3,245.2			$ 3,066.0

(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) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.0% at September 30, 2016.
(3) Net of amortization of $8.0 million at September 30, 2016 and $5.1 million at December 31, 2015, respectively.

Company Credit Facility. The Company has a $250.0 million revolving credit facility, which includes a $125.0 million letter of credit subfacility (the “credit facility”). Our obligations under the credit facility are guaranteed by two of our wholly-owned subsidiaries and secured by first priority liens on (i) 88,528,451 Partnership common units and the 100% membership interest in the General Partner indirectly held by us, (ii) the 100% equity interest in each of our wholly-owned subsidiaries held by us and (iii) any additional equity interests subsequently pledged as collateral under the credit facility.

As of September 30, 2016 there were $23.1 million borrowings under the credit facility, leaving approximately $226.9 million available for future borrowing based on the borrowing capacity of $250.0 million.

Partnership 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 the Partnership’s 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 $23.8 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 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 the Partnership expects 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 the Partnership's 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.

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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

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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, the Partnership pays the producer for the full amount of inlet gas to the plant, and makes 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”. The Partnership’s 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, the Partnership mitigates its risk of processing natural gas when margins are negative primarily through its ability to bypass processing when it is not profitable for the Partnership, 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, the Partnership receives 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, the Partnership’s margins from these contracts are greater during periods of high liquids prices. The Partnership’s margins from processing cannot become negative under percent of liquids contracts, but do decline during periods of low liquids prices.

3.Percent of proceeds contracts: Under these contracts, the Partnership receives a fee as a portion of the proceeds of the sale of natural gas and liquids. Therefore, the Partnership’s margins from these contracts are greater during periods of high natural gas and liquids prices. The Partnership’s 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.

The Partnership’s primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a risk management committee, including members of senior management, which oversees all hedging activity. The Partnership enters 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 its risk management committee.

The Partnership has hedged its exposure to fluctuations in prices for natural gas and NGL volumes produced for its account. The Partnership hedges its exposure based on volumes it considers 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, the Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the Partnership’s 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 the Partnership’s business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of

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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 the Partnership faces is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. The Partnership enters 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 the Partnership with short or long positions that must be covered. The Partnership uses financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose the Partnership 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 the Partnership engages in hedging activities, it may be prevented from realizing the benefits of favorable price changes in the physical market. However, the Partnership is 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

The Company is exposed to interest rate risk on our variable rate credit facility. At September 30, 2016, the credit facility had $23.1 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change its annual interest expense by approximately $0.2 million for the year.

The Partnership is exposed to interest rate risk on its variable rate credit facility. At September 30, 2016, the Partnership’s credit facility had $75.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change its annual interest expense by approximately $0.8 million for the year. The Partnership is not exposed to changes in interest rates with respect to its senior unsecured notes due in 2019, 2022, 2024, 2025, 2026, 2044, or 2045 as these are fixed-rate obligations. The estimated fair value of the Partnership's 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 the Partnership's 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 the Partnership's 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 Manager, 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

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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.

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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 15, “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.

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Item 6. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-4, file No. 333-192419).
3.2	—	Certificate of Amendment to Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-4, file No. 333-192419).
3.3	—	First Amended and Restated Operating Agreement of EnLink Midstream, LLC, dated as of March 7, 2014 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 7, 2014, filed with the Commission on March 11, 2014, file No. 001-36336).
3.4	—	Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.12 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014).
3.5	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.13 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014).
3.6	—	First Amended and Restated Limited Liability Company Agreement of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.14 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014).
3.7	—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP’s Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, file No. 000-50067).
3.9	—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to EnLink Midstream Partners, LP’s Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
3.10	—	Eighth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP dated January 7, 2016 (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP’s Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
3.11	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to EnLink Midstream Partners, LP’s Registration Statement on Form S-1, file No. 333-97779).
3.12	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP’s Registration Statement on Form S-3, file No. 333-194465).
3.13	—	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 EnLink Midstream Partners, LP’s Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014, file No. 001-36340).
3.14	—	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 EnLink

		Midstream Partners, LP's 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, as trustee (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).

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4.2	—Fourth Supplemental Indenture, dated as of July 14, 2016, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's 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, LLC'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 Members' 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.

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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, LLC

By: EnLink Midstream Manager, LLC,
its managing member

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

November 2, 2016