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

Form 10-Q

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

for the quarterly period ended March 31, 2016

OR

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

for the transition period from to

Commission file number: 001-36340

ENLINK MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS RD.	
DALLAS, TEXAS	**75201**
(Address of principal executive offices)	(Zip Code)

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

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

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

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

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

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

As of April 22, 2016, the Registrant had 325,507,250 common units and 7,284,477 Class C Common Units outstanding.

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ENLINK MIDSTREAM PARTNERS, LP
Condensed Consolidated Balance Sheets

	March 31, 2016	December 31, 2015
	(Unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.7	$ 5.9
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3 and $0.3, respectively	40.0	37.5
Accrued revenue and other	261.3	268.7
Related party	88.4	111.1
Fair value of derivative assets	10.5	16.8
Natural gas and NGLs inventory, prepaid expenses and other	32.0	32.1
Total current assets	437.9	472.1
Property and equipment, net of accumulated depreciation of $1,847.3 and $1,757.6, respectively	6,117.0	5,666.8
Intangible assets, net of accumulated amortization of $82.1 and $54.6, respectively	1,696.7	689.9
Goodwill	420.7	987.0
Investment in unconsolidated affiliates	269.8	274.3
Other assets, net	2.4	2.7
Total assets	$ 8,944.5	$ 8,092.8
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 35.7	$ 33.2
Accounts payable to related party	22.8	14.8
Accrued gas, NGLs, condensate and crude oil purchases	202.9	206.7
Fair value of derivative liabilities	3.2	2.9
Installment payable, net of discount of $21.0	229.0	—
Other current liabilities	187.2	174.4
Total current liabilities	680.8	432.0
Long-term debt	3,195.6	3,066.8
Fair value of derivative liabilities	—	0.1
Asset retirement obligation	13.1	12.9
Installment payable, net of discount of $45.7	204.3	—
Other long-term liabilities	59.5	65.9
Deferred tax liability	73.6	73.6
Redeemable non-controlling interest	6.8	7.0
Partners' equity:		
Common unitholders (325,484,514 units issued and outstanding at March 31, 2016 and 325,090,624 units issued and outstanding at December 31, 2015)	3,367.5	4,055.8
Class C unitholders (7,284,477 units issued and outstanding at March 31, 2016 and 7,075,433 units issued and outstanding at December 31, 2015)	137.0	149.4
Preferred unitholders (50,000,000 units issued and outstanding at March 31, 2016)	736.3	—
General partner interest (1,594,974 equivalent units outstanding at March 31, 2016 and December 31, 2015)	210.4	213.4
Non-controlling interest	259.6	15.9
Total partners' equity	4,710.8	4,434.5
Commitment and Contingencies (Note 13)		
Total liabilities and partners' equity	$ 8,944.5	$ 8,092.8

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Condensed Consolidated Statements of Operations

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(Unaudited) (In millions, except per unit amounts)	
Revenues:		
Product sales	$ 588.5	$ 670.7
Product sales - affiliates	24.5	16.2
Midstream services	114.5	102.4
Midstream services - affiliates	162.6	151.0
Gain (loss) on derivative activity	(0.4)	0.2
Total revenues	889.7	940.5
Operating costs and expenses:		
Cost of sales (1)	586.2	657.4
Operating expenses (2)	98.2	98.4
General and administrative	33.2	41.9
Gain on disposition of assets	(0.2)	—
Depreciation and amortization	121.9	91.3
Impairments	566.3	—
Total operating costs and expenses	1,405.6	889.0
Operating income (loss)	(515.9)	51.5
Other income (expense):		
Interest expense, net of interest income	(43.7)	(18.9)
Income (loss) from unconsolidated affiliates	(2.4)	3.7
Other income	0.1	0.6
Total other expense	(46.0)	(14.6)
Income (loss) before non-controlling interest and income taxes	(561.9)	36.9
Income tax provision	(1.0)	(1.2)
Net income (loss)	(562.9)	35.7
Net income (loss) attributable to the non-controlling interest	(2.5)	0.1
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (560.4)	$ 35.6
General partner interest in net income	$ 7.4	$ 26.5
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (567.2)	$ 9.0
Class C partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (12.4)	$ 0.1
Preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 11.8	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:		
Basic common unit	$ (1.74)	$ 0.03
Diluted common unit	$ (1.74)	$ 0.03

(1) Includes $42.6 million and $7.9 million for the three months ended March 31, 2016 and 2015, respectively, of affiliate purchased gas, NGLs, condensate and crude oil.
(2) Includes $0.1 million for the three months ended March 31, 2016 of affiliate operating expenses.

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statement of Changes in Partners’ Equity

Three Months Ended March 31, 2016

	Common Units		Class C Common Units		Preferred Units		General Partner Interest		Non-Controlling Interest		Redeemable Non-controlling Interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	Total	$
					(Unaudited) (In millions)						
Balance, December 31, 2015	$ 4,055.8	325.2	$ 149.4	7.1	$ —	—	$ 213.4	1.6	$ 15.9	$ 4,434.5	$ 7.0
Issuance of common units	2.1	0.2	—	—	—	—	—	—	—	2.1	—
Issuance of preferred units	—	—	—	—	724.5	50.0	—	—	—	724.5	
Contribution from ENLC	—	—	—	—	—	—	—	—	237.1	237.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(1.1)	0.1	—	—	—	—	—	—	—	(1.1)	—
Unit-based compensation	3.9	—	—	—	—	—	4.0	—	—	7.9	—
Contribution from Devon	1.4	—	—	—	—	—	—	—	—	1.4	—
Distributions	(127.4)	—	—	0.2	—	—	(14.4)	—	—	(141.8)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	9.7	9.7	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	(0.6)	(0.6)	—
Distributions to redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	(0.2)
Net income (loss)	(567.2)	—	(12.4)	—	11.8	—	7.4	—	(2.5)	(562.9)	—
Balance, March 31, 2016	$ 3,367.5	325.5	$ 137.0	7.3	$ 736.3	50.0	$ 210.4	1.6	$ 259.6	$ 4,710.8	$ 6.8

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statements of Cash Flows

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net income (loss)	$ (562.9)	$ 35.7
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments	566.3	—
Depreciation and amortization	121.9	91.3
Accretion expense	0.1	0.1
Gain on disposition of assets	(0.2)	—
Non-cash unit-based compensation	7.9	13.8
(Gain) loss on derivatives recognized in net income (loss)	0.4	(0.2)
Cash settlements on derivatives	5.6	3.9
Amortization of debt issue costs	0.8	0.6
Amortization of net (premium) discount on notes	11.7	(0.8)
Redeemable non-controlling interest expense	0.2	(2.6)
Distribution of earnings from unconsolidated affiliates	—	2.7
(Income) loss from unconsolidated affiliates	2.4	(3.7)
Changes in assets and liabilities net of assets acquired and liabilities assumed:		
Accounts receivable, accrued revenue and other	32.0	118.8
Natural gas and NGLs inventory, prepaid expenses and other	14.9	(16.3)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(12.0)	(71.6)
Net cash provided by operating activities	189.1	171.7
Cash flows from investing activities, net of assets acquired and liabilities assumed:		
Additions to property and equipment	(135.4)	(161.1)
Acquisition of business, net of cash acquired	(774.9)	(312.0)
Proceeds from sale of property	0.2	—
Investment in unconsolidated affiliates	(7.1)	—
Distribution from unconsolidated affiliates in excess of earnings	6.2	4.1
Net cash used in investing activities	(911.0)	(469.0)
Cash flows from financing activities:		
Proceeds from borrowings	379.0	959.1
Payments on borrowings	(250.0)	(487.1)
Payments on capital lease obligations	(1.1)	(1.0)
Decrease in drafts payable	—	(12.7)
Debt financing costs	(0.2)	(1.8)
Conversion of restricted units, net of units withheld for taxes	(1.1)	(2.4)
Proceeds from issuance of common units	2.1	2.2
Proceeds from issuance of preferred units	724.5	—
Distributions to non-controlling partners	(0.8)	(45.2)
Contributions by non-controlling partners	9.7	2.8
Distributions to partners	(141.8)	(99.9)
Contributions from Devon	1.4	7.9
Net cash provided by financing activities	721.7	321.9
Net increase (decrease) in cash and cash equivalents	(0.2)	24.6
Cash and cash equivalents, beginning of period	5.9	9.6
Cash and cash equivalents, end of period	$ 5.7	$ 34.2
Cash paid for interest	$ 3.3	$ 2.1
Cash paid for income taxes	$ 1.5	$ 0.1

See accompanying notes to condensed consolidated financial statements.

(1) General

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

(a) Organization of Business

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol "ENLK." Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership.

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

Effective as of January 7, 2016, the Operating Partnership acquired 84% of the outstanding equity interests in TOM, and ENLC acquired the remaining 16% equity interests in TOM. Since we control TOM, we reflect our ownership in TOM on a consolidated basis and ENLC's ownership is reflected as a non-controlling interest in the respective condensed consolidated financial statements and related disclosures.

(b) Nature of Business

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

(2) Significant Accounting Policies

(a) *Basis of Presentation*

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

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

(b) Recent Accounting Pronouncements

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 $23.0 million of debt issuance costs from "Other Assets, Net" to "Long-term debt" in our accompanying Condensed Consolidated Balance Sheet as of December 31, 2015.

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

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

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

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

In 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 are currently evaluating the impact this standard will have on our condensed consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU 2016-08, *Principal versus Agent Considerations* ("ASU 2016-08"). The new standard retained the guidance that the principal in an arrangement controls a good or service before it is transferred to a customer, and revised and clarified the indicators to evaluate when making this determination. ASU 2016-08 has the same effective date and transition requirements as the new revenue standard, which is effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods. Early application is permitted for annual reporting periods beginning after December 15, 2016. The update will have no impact on our condensed consolidated financial statements or related disclosures.

In March 2016, the FASB issued ASU 2016-07, *Simplifying the Transition to the Equity Method of Accounting* ("ASU 2016-07"). The new standard eliminates the requirement to apply the equity method of accounting retrospectively when a reporting entity obtains significant influence over a previously held investment. Investors should add the cost of acquiring the additional interest in the investee (if any) to the current basis of their previously held interest. ASU 2016-07 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 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 January 2016, the FASB issued ASU 2016-01, *Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities* ("ASU 2016-01"). Under this new standard, the FASB issued new guidance related to accounting for unconsolidated affiliate investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. ASU 2016-01 is effective for annual reporting periods beginning after December 15, 2017 including interim periods within those annual periods. Early adoption is permitted. 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. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and is to be applied retrospectively, with early application permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact the pronouncement will have on our condensed consolidated financial statements and related disclosures.

(3) Acquisitions

Matador Acquisition

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

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

Purchase Price Allocation (in millions):		
Assets acquired:		
Current assets	$	1.1
Property, plant and equipment		36.2
Intangibles		98.8
Goodwill		9.1
Liabilities assumed:		
Current liabilities		(3.9)
Total identifiable net assets	$	141.3

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

Deadwood Acquisition

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

Tall Oak Acquisition

On January 7, 2016, we and ENLC acquired an84% and 16% interest, respectively, in TOM for approximately$1.4 billion. The first installment of$1.02 billion for the acquisition was paid at closing. The final installment of $500.0 million is due by us no later than the first anniversary of the closing date with the option to defer$250.0 million of the final installment up to 24 months following the closing date. The installment payables are valued net of discount within the total purchase price.

The first installment consisted of approximately$1.02 billion and was funded by (a) approximately$783.9 million in cash paid by us, the majority of which was derived from the proceeds from the issuance of Preferred Units, and (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and approximately $22.0 million in cash paid by ENLC. The transaction was accounted for using the acquisition method.

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

Consideration (in millions):		
Cash	$	783.9
Total installment payable, net of discount of $79.1 million assuming payments are made on January 7, 2017 and 2018		420.9
Contribution from ENLC		237.1
Total consideration	$	1,441.9

Purchase Price Allocation (in millions):		
Assets acquired:		
Current assets (including $6.8 million in cash)	$	20.2
Property, plant and equipment		423.2
Intangibles		1,034.3
Liabilities assumed:		
Current liabilities		(35.8)
Total identifiable net assets	$	1,441.9

We recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer life of approximately 15 years.

We incurred $3.6 million of direct transaction costs for the three months ended March 31, 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 March 31, 2016, we recognized $27.3 million of revenues and $14.2 million of net loss related to the assets acquired.

Pro Forma Information

The following unaudited pro forma condensed financial information for the three months ended March 31, 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. Pro forma financial information associated with the acquisitions is reflected below.

	Three Months Ended March 31,	
	2015	
	(in millions)	
Pro forma total revenues	$	1,067.6
Pro forma net income	$	10.8
Pro forma net income attributable to EnLink Midstream Partners, LP	$	14.0
Pro forma net income (loss) per common unit:		
Basic	$	(0.14)
Diluted	$	(0.14)

(4) Goodwill and Intangible Assets

Goodwill

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

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

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

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

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

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

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Three Months Ended March 31, 2016						
Balance, beginning of period	$ 703.5	$ —	$ 190.3	$ 93.2	$ —	$ 987.0
Impairment	(473.1)	—	—	(93.2)	—	(566.3)
Balance, end of period	$ 230.4	$ —	$ 190.3	$ —	$ —	$ 420.7

Intangible Assets

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

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Three Months Ended March 31, 2016			
Customer relationships, beginning of period	$ 744.5	$ (54.6)	$ 689.9
Acquisitions	1,034.3	—	1,034.3
Amortization expense	—	(27.5)	(27.5)
Customer relationships, end of period	$ 1,778.8	$ (82.1)	$ 1,696.7

The weighted average amortization period for intangible assets is 14 years. Amortization expense for intangibles was approximately $27.5 million and $11.5 million for the three months ended March 31, 2016 and 2015, respectively.

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

2016 (remaining)	$ 86.3
2017	115.1
2018	115.1
2019	115.1
2020	115.1
Thereafter	1,150.0
Total	$ 1,696.7

(5) Affiliate Transactions

We engage in various transactions with Devon and other affiliated entities. For the three months ended March 31, 2016 and 2015, Devon was a significant customer to us. Devon accounted for 21.0% and 17.8% of our revenues for the three months ended March 31, 2016 and 2015, respectively. We had an accounts receivable balance related to transactions with Devon of $88.3 million as of March 31, 2016 and $110.8 million as of December 31, 2015. Additionally, we had an accounts payable balance related to transactions with Devon of $22.8 million as of March 31, 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.

TOM 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 TOM 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 TOM 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. TOM will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

(6) Long-Term Debt

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

	March 31, 2016	December 31, 2015
Partnership credit facility (due 2020), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2016 and December 31, 2015 was 2.2% and 1.8%, respectively	$ 543.0	$ 414.0
Senior unsecured notes (due 2019), net of discount of $0.4 million at March 31, 2016 and $0.4 million at December 31, 2015, which bear interest at the rate of 2.70%	399.6	399.6
Senior unsecured notes (due 2022), including a premium of $18.2 million at March 31, 2016 and $18.9 million at December 31, 2015, which bear interest at the rate of 7.125%	180.7	181.4
Senior unsecured notes (due 2024), net of premium of $2.8 million at March 31, 2016 and $2.9 million at December 31, 2015, which bear interest at the rate of 4.40%	552.8	552.9
Senior unsecured notes (due 2025), net of discount of $1.2 million at March 31, 2016 and $1.2 million at December 31, 2015, which bear interest at the rate of 4.15%	748.8	748.8
Senior unsecured notes (due 2044), net of discount of $0.3 million at March 31, 2016 and $0.2 million at December 31, 2015, which bear interest at the rate of 5.60%	349.7	349.8
Senior unsecured notes (due 2045), net of discount of $6.8 million at March 31, 2016 and $6.9 million at December 31, 2015, which bear interest at the rate of 5.05%	443.2	443.1
Debt issuance cost, net of amortization of $5.5 million at March 31, 2016 and $4.7 million at December 31, 2015	(22.4)	(23.0)
Other debt	0.2	0.2
Debt classified as long-term	$ 3,195.6	$ 3,066.8

Credit Facility

We have 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 our credit facility, we are permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under our credit facility by an additional amount not to exceed $500 million and (2) subject to certain conditions and the consent of the requisite lenders, on two separate occasions extend the maturity date of our credit facility by one year on each occasion. Our credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in our credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

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

As of March 31, 2016, there were $10.8 million in outstanding letters of credit and $543.0 million in outstanding borrowings under our credit facility, leaving approximately $946.2 million available for future borrowing based on the borrowing capacity of$1.5 billion.

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

(7) Partners' Capital

(a) Issuance of Common Units

In November 2014, we entered into an Equity Distribution Agreement (the "BMO EDA") with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the "Sales Agents") to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program. We may also sell common units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of the common units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. For the three months ended March 31, 2016, we sold an aggregate of 0.2 million common units under the BMO EDA, generating proceeds of approximately $2.1 million (net of approximately $0.1 million of commissions). We used the net proceeds for general partnership purposes. As of March 31, 2016, approximately $314.8 million remains available to be issued under the BMO EDA.

(b) Class C Common Units

In March 2015, we issued 6,704,285 Class C Common Units representing a new class of limited partner interests as partial consideration for the acquisition of Coronado. The Class C Common Units are substantially similar in all respects to our common units, except that distributions paid on the Class C Common Units may be paid in cash or in additional Class C Common Units issued in kind, as determined by our general partner in its sole discretion. The Class C Common Units will automatically convert into common units on a one-for-one basis on May 13, 2016. Distributions on the Class C Common Units for the three months ended December 31, 2015 were paid-in-kind ("PIK") through the issuance of 209,044 Class C Common Units on February 11, 2016. A distribution on the Class C Common Units of $0.390 per unit was declared for the three months ended March 31, 2016, which will result in the issuance of 233,107 additional Class C Common Units on May 12, 2016.

(c) Preferred Units

In January 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing our limited partner interests to Enfield Holdings, L.P. ("Enfield") in a private placement for a cash purchase price of $15.00 per Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.5 million after fees and deductions. Proceeds from the Private Placement were used to partially fund our portion of the purchase price payable in connection with the Tall Oak acquisition. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield. The Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, at any time after the record date for the quarter ending June 30, 2017 (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Preferred Units would then convert and (ii) the number of Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

Enfield will 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. A distribution on the Preferred Units was declared for the three months ended March 31, 2016, which will result in the issuance of 992,445 additional Preferred Units distributable on May 12, 2016. Income was allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period earned. For the three months ended March 31, 2016, $11.8 million of income was allocated to the preferred units.

(d) Distributions

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

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

A summary of the distribution activity relating to the common units for the three months ended March 31, 2016 is provided below:

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

(e) Earnings per Unit and Dilution Computations

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

	Three Months Ended March 31,	
	2016	2015
Limited partners' interest in net income (loss)	$ (567.2)	$ 9.0
Distributed earnings allocated to:		
Common units (1)	$ 126.9	$ 99.5
Unvested restricted units (1)	0.8	0.4
Total distributed earnings	$ 127.7	$ 99.9
Undistributed loss allocated to:		
Common units	$ (690.7)	$ (90.5)
Unvested restricted units	(4.2)	(0.4)
Total undistributed loss	$ (694.9)	$ (90.9)
Net income (loss) allocated to:		
Common units	$ (563.8)	$ 9.0
Unvested restricted units	(3.4)	—
Total limited partners' interest in net income (loss)	$ (567.2)	$ 9.0
Basic and diluted net income (loss) per unit:		
Basic	$ (1.74)	$ 0.03
Diluted	$ (1.74)	$ 0.03

(1) Three months ended March 31, 2016 and 2015 represents a declared distribution of $0.39 per unit payable on May 12, 2016 and a distribution of $0.38 per unit paid on May 14, 2015, respectively.

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

	Three Months Ended March 31,	
	2016	2015
Basic weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	325.2	261.8
Weighted average Class C Common Units outstanding	7.2	1.1
Total weighted average limited partner common units outstanding	332.4	262.9
Diluted weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	332.4	262.9
Dilutive effect of restricted units issued	—	0.4
Total weighted average limited partner diluted common units outstanding	332.4	263.3

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

Net income is allocated to our general partner in an amount equal to its incentive distributions as described in (d) above. Our general partner's share of net income consists of incentive distributions to the extent earned, a deduction for unit-based compensation attributable to ENLC's restricted units and the percentage interest of our net income adjusted for ENLC's unit-based compensation specifically allocated to our general partner. The net income allocated to our general partner is as follows for the periods presented (in millions):

	Three Months Ended March 31,	
	2016	2015
Income allocation for incentive distributions	$ 13.8	$ 8.8
Unit-based compensation attributable to ENLC's restricted units	(4.0)	(7.0)
General partner share of net income (loss)	(2.4)	0.1
General partner interest in drop down transactions	—	24.6
General partner interest in net income	$ 7.4	$ 26.5

(8) Asset Retirement Obligations

The schedule below summarizes the changes in our asset retirement obligation:

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Beginning asset retirement obligations	$ 14.0	$ 20.6
Revisions to existing liabilities	(0.4)	(3.9)
Accretion	0.1	0.1
Liabilities settled	(0.6)	(3.2)
Ending asset retirement obligations	$ 13.1	$ 13.6

There are no asset retirement obligations included in Other Current Liabilities as of March 31, 2016. Asset retirement obligations of$1.1 million is included in Other Current Liabilities as of March 31, 2015.

(9) Investment in Unconsolidated Affiliates

Our unconsolidated investments consisted of a contractual right to the economic benefits and burdens associated with Devon's38.75% ownership interest in Gulf Coast Fractionators (“GCF”) at March 31, 2016 and 2015 and a 30.6% ownership interest in Howard Energy Partners (“HEP”) at March 31, 2016 and 2015.

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

	Gulf Coast Fractionators	Howard Energy Partners	Total
Three months ended			
March 31, 2016			
Contributions	$ —	$ 7.1	$ 7.1
Distributions	$ 3.0	$ 6.2	$ 9.2
Equity in net loss	$ (1.7)	$ (0.7)	$ (2.4)
March 31, 2015			
Distributions	$ 2.7	$ 4.1	$ 6.8
Equity in net income	$ 3.3	$ 0.4	$ 3.7

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

	March 31, 2016	December 31, 2015
Gulf Coast Fractionators	$ 47.9	$ 52.6
Howard Energy Partners	221.9	221.7
Total investment in unconsolidated affiliates	$ 269.8	$ 274.3

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

We account for unit-based compensation in accordance with FASB ASC 718, which requires that compensation related to all unit-based awards, including unit options, be recognized in the condensed consolidated financial statements. On April 7, 2016, our general partner amended and restated the EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”). Amendments to the GP Plan included an increase to the number of common units of the Partnership authorized for issuance under the GP Plan by 5,000,000 common units to an aggregate of14,070,000 common units and other technical changes.

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

	Three Months Ended March 31,	
	2016	2015
Cost of unit-based compensation charged to general and administrative expense	$ 6.2	$ 11.9
Cost of unit-based compensation charged to operating expense	1.7	1.9
Total amount charged to income	$ 7.9	$ 13.8

(b) EnLink Midstream Partners, LP Restricted Incentive Units

Our restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of common units on such date. A summary of the restricted incentive unit activity for the three months ended March 31, 2016 is provided below:

	Three Months Ended March 31, 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	1,041,022	10.01
Vested*	(294,460)	30.40
Forfeited	(27,797)	24.12
Non-vested, end of period	1,972,494	$ 19.21
Aggregate intrinsic value, end of period (in millions)	$ 23.8	

* Vested units include 84,429 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 months ended March 31, 2016 and 2015 are provided below (in millions):

	Three Months Ended March 31,	
EnLink Midstream Partners, LP Restricted Incentive Units:	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 3.7	$ 6.8
Fair value of units vested	$ 9.0	$ 7.0

As of March 31, 2016, there was $22.4 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 1.9 years.

(c) EnLink Midstream Partners, LP Performance Units

During the first quarter of 2016, our general partner and the managing member of ENLC granted performance awards under the GP Plan and the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "LLC Plan"), respectively. The performance award agreements provide that the vesting of restricted incentive units granted thereunder is dependent on the achievement of certain total shareholder return ("TSR") performance goals relative to the TSR achievement of a peer group of companies (the "Peer Companies") over the applicable performance period. The performance award agreements contemplate that the Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding us and ENLC (collectively, "EnLink"), on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of the Partnership's and ENLC's TSR achievement ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Peer Companies.

At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units range from zero to 200 percent of the units granted depending on the EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated peer group securities; (iii) an estimated ranking of us among the designated peer group and (iv) the distribution yield. The fair value of the unit on the date of grant is expensed over a vesting period of three years. The following table presents a summary of the grant-date fair values of performance units granted and the related assumptions:

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

The following table presents a summary of our performance units:

	Three Months Ended March 31, 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)	$ 4.5	

As of March 31, 2016, there was$4.9 million of unrecognized compensation expense that related to our non-vested performance units. That cost is expected to be recognized over a weighted-average period of 2.2 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 three months ended March 31, 2016 is provided below:

	Three Months Ended March 31, 2016	
EnLink Midstream, LLC Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,148,893	$ 34.78
Granted	1,032,976	9.42
Vested*	(317,726)	37.03
Forfeited	(24,970)	26.85
Non-vested, end of period	1,839,173	$ 20.26
Aggregate intrinsic value, end of period (in millions)	$ 20.7	

* Vested units include 90,326 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 months ended March 31, 2016 and 2015 are provided below (in millions):

	Three Months Ended March 31,	
EnLink Midstream, LLC Restricted Incentive Units:	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 3.8	$ 8.3
Fair value of units vested	$ 11.8	$ 8.6

As of March 31, 2016, there was $21.9 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 1.9 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 ENLC's performance units:

	Three Months Ended March 31, 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)	$ 3.9	

As of March 31, 2016, there was $4.7 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 2.2 years.

(11) Derivatives

Commodity Swaps

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

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

The components of gain (loss) on derivative activity in the Condensed Consolidated Statements of Operations relating to commodity swaps are (in millions):

	Three Months Ended March 31,	
	2016	2015
Change in fair value of derivatives	$ (6.0)	$ (3.7)
Realized gain on derivatives	5.6	3.9
Gain (loss) on derivative activity	$ (0.4)	$ 0.2

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

	March 31, 2016	December 31, 2015
Fair value of derivative assets — current	$ 10.5	$ 16.8
Fair value of derivative liabilities — current	(3.2)	(2.9)
Fair value of derivative liabilities — long term	—	(0.1)
Net fair value of derivatives	$ 7.3	$ 13.8

The total estimated fair value of derivative contracts of $7.3 million as of March 31, 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 March 31, 2016. The remaining term of the contracts extend no later than March 2017.

			March 31, 2016	
Commodity	Instruments	Unit	Volume	Fair Value
			(In millions)	
NGL (short contracts)	Swaps	Gallons	(42.9)	$ 8.8
NGL (long contracts)	Swaps	Gallons	17.1	(1.8)
Natural Gas (short contracts)	Swaps	MMBtu	(6.7)	0.8
Natural Gas (long contracts)	Swaps	MMBtu	2.2	(0.3)
Condensate (short contracts)	Swaps	MMBbls	(0.1)	(0.2)
Total fair value of derivatives				$ 7.3

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. We have entered into Master International Swaps and Derivatives Association Agreements (“ISDAs”) that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing swap contracts, our maximum loss as of March 31, 2016 of $10.5 million would be reduced to $7.3 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(12) Fair Value Measurements

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

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

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

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

	March 31, 2016 Level 2	December 31, 2015 Level 2
Commodity Swaps*	$ 7.3	$ 13.8
Total	$ 7.3	$ 13.8

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

Fair Value of Financial Instruments

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

	March 31, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,195.6	$ 2,629.0	$ 3,066.8	$ 2,585.5
Obligations under capital leases	$ 13.4	$ 12.7	$ 16.7	$ 15.6

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

We had $543.0 million and $414.0 million in outstanding borrowings under our revolving credit facility as of March 31, 2016 and December 31, 2015, respectively. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of March 31, 2016 and December 31, 2015, we had total borrowings of $2.7 billion under senior unsecured notes maturing between 2019 and 2045 with fixed interest rates ranging from 2.7% to 7.1%. The fair value of all senior unsecured notes as of March 31, 2016 and December 31, 2015 was based on Level 2 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) Severance and Change in Control Agreements

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

(b) Environmental Issues

The operation of pipelines, plants and other facilities for the gathering, processing, transmitting or disposing of natural gas, NGLs, crude oil, condensate, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows. In February 2016, a spill occurred at our Kill Buck Station in our Ohio operations. State and federal agencies were notified and clean-up response efforts were promptly executed, which significantly lessened the impact of the spill. On April 7, 2016, the state agency determined that the clean-up recovery efforts were completed and has internally transitioned monitoring to their water quality division. We do not anticipate a material fine or penalty by either the state or federal agencies. Additionally, although the spill that previously occurred in our West Virginia operations in the third quarter of 2015 is still pending, we do not believe that any fine or penalty that may be issued will be material to our operations. Lastly, we continue to work with Pipeline and Hazardous Materials Safety Administration regarding the notice of potential violation discussed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

(c) Litigation Contingencies

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

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

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

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

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

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

(14) Segment Information

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

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

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

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
	(In millions)					
Three Months Ended March 31, 2016						
Product sales	$ 62.5	$ 287.7	$ 7.8	$ 230.5	$ —	$ 588.5
Product sales-affiliates	37.3	7.4	10.6	0.2	(31.0)	24.5
Midstream services	27.4	55.2	15.1	16.8	—	114.5
Midstream services-affiliates	110.3	12.7	45.0	5.2	(10.6)	162.6
Cost of sales	(91.3)	(302.1)	(19.3)	(215.1)	41.6	(586.2)
Operating expenses	(39.3)	(23.3)	(12.8)	(22.8)	—	(98.2)
Loss on derivative activity	—	—	—	—	(0.4)	(0.4)
Segment profit	$ 106.9	$ 37.6	$ 46.4	$ 14.8	$ (0.4)	$ 205.3
Depreciation and amortization	$ (46.2)	$ (29.3)	$ (33.8)	$ (10.4)	$ (2.2)	$ (121.9)
Impairments	$ (473.1)	$ —	$ —	$ (93.2)	$ —	$ (566.3)
Goodwill	$ 230.4	$ —	$ 190.3	$ —	$ —	$ 420.7
Capital expenditures	$ 23.3	$ 22.7	$ 69.2	$ 3.3	$ 1.9	$ 120.4
Three Months Ended March 31, 2015						
Product sales	$ 49.8	$ 372.2	$ —	$ 248.7	$ —	$ 670.7
Product sales-affiliates	25.9	7.1	3.7	—	(20.5)	16.2
Midstream services	19.6	57.9	10.7	14.2	—	102.4
Midstream services-affiliates	115.5	0.1	31.2	4.2	—	151.0
Cost of sales	(67.2)	(370.9)	(5.1)	(234.7)	20.5	(657.4)
Operating expenses	(47.0)	(24.3)	(7.0)	(20.1)	—	(98.4)
Gain on derivative activity	—	—	—	—	0.2	0.2
Segment profit	$ 96.6	$ 42.1	$ 33.5	$ 12.3	$ 0.2	$ 184.7
Depreciation and amortization	$ (36.4)	$ (27.5)	$ (13.5)	$ (12.4)	$ (1.5)	$ (91.3)
Goodwill	$ 1,168.2	$ 786.8	$ 190.3	$ 137.8	$ —	$ 2,283.1
Capital expenditures	$ 73.5	$ 15.2	$ 5.2	$ 77.6	$ 4.2	$ 175.7

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

	March 31, 2016	December 31, 2015
Segment Identifiable Assets:	(In millions)	
Texas	$ 3,175.4	$ 3,709.5
Louisiana	2,290.6	2,309.3
Oklahoma	2,380.7	873.4
Crude and Condensate	798.1	898.0
Corporate	299.7	302.6
Total identifiable assets	$ 8,944.5	$ 8,092.8

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

	Three Months Ended March 31,	
	2016	2015
Segment profits	$ 205.3	$ 184.7
General and administrative expenses	(33.2)	(41.9)
Gain on disposition of assets	0.2	—
Depreciation and amortization	(121.9)	(91.3)
Impairments	(566.3)	—
Operating income (loss)	$ (515.9)	$ 51.5

(15) Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2016	2015
Non-cash financing activities:	(In millions)	
Installment payable, net of discount of $79.1 million (1)	$ 420.9	$ —
Non-cash issuance of common units (2)	—	180.0
Non-cash issuance of Class C Common Units (2)	—	180.0
Contribution from ENLC (3)	237.1	—
Non-cash adjustment of interest in Midstream Holdings (4)	—	20.9

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

(16) Other Information

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

Other Current Liabilities

Other current liabilities consisted of the following:

	March 31, 2016	December 31, 2015
	(in millions)	
Accrued interest	$ 53.3	$ 23.2
Accrued wages and benefits, including taxes	7.5	27.7
Accrued ad valorem taxes	12.5	27.0
Capital expenditure accruals	32.0	22.3
Onerous performance obligations	16.6	17.0
Other	65.3	57.2
Other current liabilities	$ 187.2	$ 174.4

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

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

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

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission, fractionation, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 9,900 miles of pipelines, 18 natural gas processing plants, seven fractionators, 3.2 million barrels of NGL cavern storage, 19.1 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 150 trucks. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments: (1) Texas, which includes our natural gas gathering, processing and transmission activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes our natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK") and Central Northern Oklahoma Woodford ("CNOW") Shale areas; (3) Louisiana, which includes our natural gas pipelines, natural gas processing plants and NGL assets located in Louisiana; (4) Crude and Condensate, which includes our Ohio River Valley ("ORV") crude oil, condensate and brine disposal activities in the Utica and Marcellus Shales, our equity interests in E2 Energy Services, LLC, E2 Appalachian Compression, LLC and E2 Ohio Compression, LLC (collectively, "E2"), our crude oil operations in the Permian Basin and our crude oil activities associated with the Victoria Express Pipeline and related truck terminal and storage assets ("VEX") located in the Eagle Ford Shale; and (5) Corporate, which includes our unconsolidated affiliate investments in Howard Energy Partners ("HEP") in the Eagle Ford Shale, our contractual right to the economic burdens and benefits associated with Devon's ownership interest in Gulf Coast Fractionators ("GCF") in south Texas and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to gather, process, transport or market natural gas, NGLs, crude oil and condensate using our assets for a fee. We earn our fees through various contractual arrangements, which include stated fixed-fee contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin for our fee. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. We define gross operating margin as operating revenue minus cost of sales. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 98% of our gross operating margin (revenues less cost of sales) was derived from fee-based services with no direct commodity exposure for the three months ended March 31, 2016. We reflect revenue as "Product sales" and "Midstream services" on the Condensed Consolidated Statements of Operations.

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

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

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

On occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our fee. Changes in the basis spread can increase or decrease our margins or potentially result in losses. For example, we are a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices on our North Texas Pipeline and sell the gas into a different market area index. We realize a cash loss on the delivery of gas under this contract each month based on current prices. The fair value of this performance obligation was recorded based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of March 31, 2016, the balance sheet reflects a liability of $58.3 million related to this performance obligation. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

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

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

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

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

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

Recent Developments

Acquisition

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

The first installment consisted of approximately $1.02 billion and was funded by (a) approximately $783.9 million in cash paid by us, the majority of which was derived from the proceeds from the issuance of Preferred Units (as defined under "Issuance of Preferred Units" below), and (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and approximately $22.0 million in cash paid by ENLC.

TOM's 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 15 years. TOM's 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 100 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.
- *Battle Ridge Plant.* The Battle Ridge Plant, which provides us with an entry into the CNOW play, is a cryogenic gas processing plant with a current capacity of 75 MMcf/d. Depending on future volume requirements, the Battle Ridge Plant could be expanded by an additional 400 MMcf/d for a total processing capacity of 475 MMcf/d. The plant is connected to a 175-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.
- *Connecting Pipeline.* A 42-mile, 16-inch high-pressure header pipeline with a total capacity of 150 MMcf/d was constructed to connect the Chisolm and Battle Ridge systems. The pipeline went into service in March 2016 and provides customers with additional operational flexibility.

Organic Growth

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. 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 are expected to be completed in the second half 2016 with the remaining New Mexico pipeline to be completed in the first quarter of 2017. The Lobo II system is supported by a long-term contract with a producer with an investment grade credit rating.

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

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

HEP. During 2016, we plan to make contributions to HEP, primarily to fund our equity share of HEP's Nueva Era Pipeline. The Nueva Era Pipeline is a 50-50 joint venture between HEP and Mexico-based energy and services firm Grupo Clisa connecting 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.

Issuance of Units

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

For the three months ended March 31, 2016, we sold an aggregate of0.2 million common units under the BMO EDA, generating proceeds of approximately$2.1 million (net of approximately $0.1 million of commissions). We used the net proceeds for general partnership purposes. As of March 31, 2016, approximately $314.8 million remains available to be issued under the agreement.

Issuance of Preferred Units

On January 7, 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing limited partner interests in our partnership (the "Preferred Units") to Enfield Holdings, L.P. ("Enfield") in a private placement (the "Private Placement") for a cash purchase price of $15.00 per Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.5 million after fees and deductions. Proceeds from the Private Placement were used to partially fund our portion of the purchase price payable in connection with the Tall Oak acquisition. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield.

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

Enfield will 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. Income is allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period earned.

Non-GAAP Financial Measures

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

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus interest expense, provision for income taxes, depreciation and amortization expense, impairment expense, unit-based compensation, (gain) loss on non-cash derivatives, (gain) loss on disposition of assets, transaction costs, accretion expense associated with asset retirement obligations, reimbursed employee costs, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, and income (loss) from unconsolidated affiliate investments. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

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

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

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

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

Reconciliation of net income (loss) to adjusted EBITDA

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Net income (loss)	$ (562.9)	$ 35.7
Interest expense	43.7	18.9
Depreciation and amortization	121.9	91.3
Impairments	566.3	—
(Income) loss from unconsolidated affiliate investments	2.4	(3.7)
Distributions from unconsolidated affiliate investments	9.2	6.8
Gain on disposition of assets	(0.2)	—
Unit-based compensation	7.9	13.8
Income taxes	1.0	1.2
Payments under onerous performance obligation offset to other current and long-term liabilities	(4.4)	(4.5)
Other (1)	10.9	10.7
Adjusted EBITDA before non-controlling interest	$ 195.8	$ 170.2
Non-controlling interest share of adjusted EBITDA	(0.8)	(0.1)
Transferred interest adjusted EBITDA (2)	—	(40.2)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 195.0	$ 129.9

(1) Includes financial derivatives marked-to-market, accretion expense associated with asset retirement obligations, reimbursed employee costs from Devon and LPC, acquisition transaction costs and non-cash rent.
(2) Represents recast adjusted EBITDA from assets acquired from ENLC and Devon in drop down transactions during the first half of 2015 for the period prior to the date of the drop down transactions.

Distributable Cash Flow

We define distributable cash flow as net cash provided by operating activities plus adjusted EBITDA, net to EnLink Midstream Partners, LP, less interest expense (excluding amortization of the Tall Oak acquisition installment payable discount), adjustments for the mandatorily redeemable non-controlling interest, cash taxes and other, and maintenance capital expenditures. Distributable cash flow is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner.

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

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

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

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Net cash provided by operating activities	$ 189.1	$ 171.7
Interest expense, net (1)	31.4	21.7
Current income tax	1.0	1.2
Distributions from unconsolidated affiliate investments in excess of earnings	9.2	4.1
Other (2)	4.5	6.9
Changes in operating assets and liabilities which provided cash:		
Accounts receivable, accrued revenues, inventories and other	(46.9)	(102.5)
Accounts payable, accrued gas and crude oil purchases and other (3)	7.5	67.1
Adjusted EBITDA before non-controlling interest	$ 195.8	$ 170.2
Non-controlling interest share of adjusted EBITDA	(0.8)	(0.1)
Transferred interest adjusted EBITDA (4)	—	(40.2)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 195.0	$ 129.9
Interest expense	(43.7)	(18.9)
Amortization of Tall Oak installment payable discount included in interest expense (5)	12.4	—
Non-cash adjustment for mandatorily redeemable non-controlling interest	0.2	(2.6)
Cash taxes and other	(1.0)	(0.8)
Maintenance capital expenditures	(7.5)	(8.9)
Distributable cash flow	$ 155.4	$ 98.7

(1) Net of amortization of debt issuance costs, discount and premium, and valuation adjustment for mandatorily redeemable non-controlling interest included in interest expense.
(2) Includes acquisition transaction costs and reimbursed employee costs from Devon and LPC.
(3) Net of payments under onerous performance obligation offset to other current and long-term liabilities.
(4) Represents recast adjusted EBITDA from assets acquired from ENLC and Devon in drop down transactions during the first half of 2015 for the period prior to the date of the drop down transactions.
(5) Amortization of the Tall Oak acquisition installment payable discount is considered non-cash interest under our credit facility since the payment under the payable is consideration for the acquisition of Tall Oak.

Gross Operating Margin

We define gross operating margin, generally, as revenues less cost of purchased gas, NGLs, condensate and crude oil. 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. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

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

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Total gross operating margin	$ 303.5	$ 283.1
Add (Deduct):		
Operating expenses	(98.2)	(98.4)
General and administrative expenses	(33.2)	(41.9)
Gain on disposition of assets	0.2	—
Depreciation and amortization	(121.9)	(91.3)
Impairments	(566.3)	—
Operating income (loss)	$ (515.9)	$ 51.5

Results of Operations

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

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(in millions, except volumes)	
Texas Segment		
Revenues	$ 237.5	$ 210.8
Cost of sales	(91.3)	(67.2)
Total gross operating margin	$ 146.2	$ 143.6
Louisiana Segment		
Revenues	$ 363.0	$ 437.3
Cost of sales	(302.1)	(370.9)
Total gross operating margin	$ 60.9	$ 66.4
Oklahoma Segment		
Revenues	$ 78.5	$ 45.6
Cost of sales	(19.3)	(5.1)
Total gross operating margin	$ 59.2	$ 40.5
Crude and Condensate Segment		
Revenues	$ 252.7	$ 267.1
Cost of sales	(215.1)	(234.7)
Total gross operating margin	$ 37.6	$ 32.4
Corporate		
Revenues	$ (42.0)	$ (20.3)
Cost of sales	41.6	20.5
Total gross operating margin	$ (0.4)	$ 0.2
Total		
Revenues	$ 889.7	$ 940.5
Cost of sales	(586.2)	(657.4)
Total gross operating margin	$ 303.5	$ 283.1
Midstream Volumes:		
Texas		
Gathering and Transportation (MMBtu/d)	2,743,400	2,751,000
Processing (MMBtu/d)	1,198,100	1,136,300
Louisiana		
Gathering and Transportation (MMBtu/d)	1,475,000	1,355,400
Processing (MMBtu/d)	517,800	434,400
NGL Fractionation (Gals/d)	5,020,200	5,632,000
Oklahoma		
Gathering and Transportation (MMBtu/d)	617,000	431,800
Processing (MMBtu/d)	569,700	356,500
Crude and Condensate		
Crude Oil Handling (Bbls/d)	124,700	89,900
Brine Disposal (Bbls/d)	3,500	3,600

Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015

Gross Operating Margin. Gross operating margin was $303.5 million for the three months ended March 31, 2016 as compared to $283.1 million for the three months ended March 31, 2015, an increase of $20.4 million, or 7.2%. The overall increase in gross operating margin was due to acquisitions in our Texas, Oklahoma and Crude & Condensate segments during 2015 and 2016 which contributed an aggregate increase of $30.1 million in gross operating margin between periods. This increase was partially offset by declines in gross operating margins from our other assets due to both volume and price declines as discussed more fully below. The following provides additional details regarding these changes in gross operating margin by segment:

- *Texas Segment.* The Texas segment had an increase in gross operating margin of $2.6 million for the three months ended March 31, 2016 compared to the three months ended March 31, 2015. The Texas segment increase was primarily attributable to an increase of $11.8 million in gross operating margin due to the Coronado acquisition in March 2015, the Matador acquisition in October 2015 and the Deadwood acquisition in November 2015. The increase attributable to acquisitions was partially offset by a decrease of $9.2 million in gross operating margin from our other assets primarily attributable to volume declines on our north Texas processing, gathering and transmission assets.

- *Louisiana Segment.* The Louisiana segment had a decrease in gross operating margin of $5.5 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. This decrease was primarily attributable to a decrease of $4.8 million from our NGL business, which was driven by declines in fractionation volumes between periods due to a decline in NGL prices coupled with a decline in volumes due to scheduled maintenance on our fractionators during the first quarter of 2016.

- *Oklahoma Segment.* The Oklahoma segment had an increase in gross operating margin of $18.7 million for the three months March 31, 2016 compared to the three months ended March 31, 2015. This increase was primarily driven by an increase of $12.8 million in gross operating margin due to the Tall Oak acquisition in January 2016. In addition, our gross operating margin from our Cana gathering and processing assets increased by $5.2 million between periods due to increased volumes combined with the expansion of our compression facilities, which were completed in October 2015.

- *Crude & Condensate Segment.* The Crude and Condensate segment had an increase in gross operating margin of $5.2 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. This increase was attributable to the acquisition of the LPC assets in January 2015, which contributed an increase in gross operating margin of $5.5 million between periods. In addition, gross operating margin from our compression and condensate stabilization facilities located in the ORV increased by $1.9 million between periods primarily due to the construction of new facilities which commenced operation at various times in 2015. These increases were partially offset by a $2.5 million decrease from our other crude operations related to the termination of a customer contract in June 2015.

Operating Expenses. Operating expenses were $98.2 million for the three months ended March 31, 2016 as compared to $98.4 million for the three months ended March 31, 2015, a decrease of $0.2 million, or 0.2%. The primary contributors to the total decrease are as follows:

	Three Months Ended March 31,		Change	
	2016	**2015**	**$**	**%**
	(in millions)			
Texas Segment	$ 39.3	$ 47.0	$ (7.7)	(16.4)%
Louisiana Segment	23.3	24.3	(1.0)	(4.1)%
Oklahoma Segment	12.8	7.0	5.8	82.9 %
Crude and Condensate Segment	22.8	20.1	2.7	13.4 %
Total	$ 98.2	$ 98.4	$ (0.2)	(0.2)%

- *Texas Segment.* Operating expenses in our Texas segment decreased $7.7 million for the three months ended March 31, 2016 as compared to the same three-month period in 2015. Of this decrease, $5.0 million is attributable to a lower level of overhaul and maintenance expenditures during the first quarter of 2016 as compared to 2015 largely due to timing of field work, $1.1 million is attributable to tax refunds related to operating activities received in the first quarter of 2016, and the remaining decrease is due to cost reduction measures. This decrease is partially offset by a $3.4 million increase attributable to the March 2015 Coronado acquisition, October 2015 Matador acquisition and November 2015 Deadwood acquisition.

- *Oklahoma Segment.* Operating expenses in our Oklahoma segment increased $5.8 million for the three months ended March 31, 2016 as compared to the same three-month period in 2015. The increase is attributable to the Tall Oak acquisition that occurred in January 2016.

- *Crude & Condensate Segment.* Operating expenses in our Crude and Condensate segment increased $2.7 million for the three months ended March 31, 2016 as compared to the same three-month period in 2015. The primary increase is attributable to the operation of the assets acquired in the January 2015 LPC acquisition for a full three months in 2016, as opposed to approximately two months in 2015.

General and Administrative Expenses. General and administrative expenses were $33.2 million for the three months ended March 31, 2016 as compared to $41.9 million for the three months ended March 31, 2015, a decrease of $8.7 million, or 20.8%. The primary contributors to the total decrease are as follows:

- our unit-based compensation expense decreased $5.6 million primarily due to bonuses being paid in the form of units that immediately vested in March 2015;

- our software consulting fees decreased $1.5 million; and

- our transition service fees associated with acquisitions decreased by $1.0 million.

Depreciation and Amortization. Depreciation and amortization expenses were $121.9 million for the three months ended March 31, 2016 as compared to $91.3 million for the three months ended March 31, 2015, an increase of $30.6 million, or 33.5%. Of this increase in depreciation and amortization expense, $19.8 million is attributable to the acquisition of the TOM assets from Tall Oak in January 2016, $7.0 million is attributable to the acquisition of the Coronado assets in March 2015, $2.0 million is attributable to the LPC asset acquisition in January 2015, $1.5 million is attributable to the Matador acquisition in October 2015 and $1.7 million is attributable to the decommissioning of certain pipeline assets in Louisiana. The remaining increase in depreciation and amortization expense is primarily attributable to assets placed in service. This increase was partially offset by a $5.4 million decrease in amortization attributable to the impairment of Ohio River Valley intangible assets in August 2015.

Impairments. Impairment expense was $566.3 million for the three months ended March 31, 2016. During March 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments. For more information, see “Critical Accounting Policies-Impairment of Goodwill” below.

Interest Expense. Interest expense was $43.7 million for the three months ended March 31, 2016 as compared to $18.9 million for the three months ended March 31, 2015, an increase of $24.8 million, or 131.2%. Of the increase in interest expense, $10.5 million is attributable to an increase in average debt in 2016 compared to 2015, $12.4 million is attributable to an increase in amortization of discount due to the Tall Oak acquisition installment payments, and $2.8 million is attributable to an increase in non-cash interest expense related to the initial valuation of our mandatorily redeemable non-controlling interest. Net interest expense consists of the following (in millions):

	Three Months Ended March 31,	
	2016	**2015**
Senior notes	$ 30.0	$ 20.3
Credit facility	3.2	2.3
Capitalized interest	(2.6)	(1.3)
Amortization of debt issue costs and net discounts (premium)	12.5	(0.2)
Mandatory redeemable non-controlling interest	0.2	(2.6)
Other	0.4	0.4
Total	$ 43.7	$ 18.9

Income (loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $2.4 million for the three months ended March 31, 2016 compared to income of $3.7 million for the three months ended March 31, 2015, a decrease of $6.1 million. This decrease is primarily due to a decline of $5.0 million in income from our GCF investment between periods due to an increase in operating costs for major scheduled maintenance on the fractionator during the first quarter of 2016.

Critical Accounting Policies

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

Impairment of Goodwill. We conduct our annual goodwill impairment test in the fourth quarter each year. During the three months ended March 31, 2016, we recognized a partial goodwill impairment of $566.3 million. 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 February 2016, we determined that continued further weakness in the overall energy sector driven by low commodity prices together with a further decline in our unit price subsequent to year-end caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis on all reporting units.

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

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

As of March 31, 2016, the goodwill allocated to our Crude and Condensate reporting unit was fully impaired. We concluded that the fair value of goodwill of our Oklahoma reporting unit substantially exceeded its carrying value, and the entire amount of goodwill disclosed on the Condensed Consolidated Balance Sheet associated with the remaining reporting unit is recoverable. However, the fair value of our Texas reporting unit is not substantially in excess of its carrying value. The fair value of our Texas reporting unit approximates its carrying value after considering the impairment loss above. As of March 31, 2016, we had $230.4 million of goodwill allocated to the Texas reporting unit.

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

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $189.1 million for the three months ended March 31, 2016 compared to $171.7 million for the three months ended March 31, 2015. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Three Months Ended March 31,	
	2016	2015
Operating cash flows before changes in working capital	$ 154.2	$ 140.8
Changes in working capital	$ 34.9	$ 30.9

The primary reason for the increase in operating cash flows before changes in working capital of$13.4 million from 2015 to 2016 relates to an increase in gross operating margin from the acquired Coronado, Matador, Deadwood and TOM assets. 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 due to normal operating fluctuations.

Cash Flows from Investing Activities. Net cash used in investing activities was $911.0 million for the three months ended March 31, 2016 and $469.0 million for the three months ended March 31, 2015. Our primary investing cash flows were acquisition costs and capital expenditures, net of accrued amounts, as follows (in millions):

	Three Months Ended March 31,	
	2016	2015
Growth capital expenditures	$ 127.9	$ 149.4
Maintenance capital expenditures	7.5	11.7
Acquisition of businesses	774.9	312.0
Proceeds from sale of property	(0.2)	—
Investment in unconsolidated affiliate investments	7.1	—
Distribution from unconsolidated affiliate investments in excess of earnings	(6.2)	(4.1)
Total	$ 911.0	$ 469.0

Growth capital expenditures decreased $21.5 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. The decrease is primarily attributable to our ORV and Permian assets due to the completions of the E2 compression and stabilization facilities and the Bearkat natural gas processing plant and rich gas gathering system in 2015. This decrease is partially offset by an increase in growth capital expenditures in our Oklahoma segment for the TOM assets.

Maintenance capital expenditures decreased $4.2 million for the three months ended March 31, 2016 compared to the three months ended March 31, 2015. The decrease is primarily attributable to decreases in compressor overhauls and repairs in our Texas and Oklahoma segments.

Acquisition expenditures increased $462.9 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. Acquisition of business during the three months ended March 31, 2016 included the Tall Oak acquisition. Acquisition of businesses during the three months ended March 31, 2015 included the LPC and Coronado acquisitions.

During the first quarter of 2016, we had an investment in unconsolidated affiliate of $7.1 million related to the Partnership's contributions to HEP. Although the Partnership is receiving quarterly distributions from HEP, the Partnership's quarterly contributions to HEP to fund its share of HEP's Nueva Era Pipeline discussed above under "Recent Developments" will be in excess of such distributions during 2016.

Cash Flows from Financing Activities. Net cash provided by financing activities was$721.7 million and $321.9 million for the three months ended March 31, 2016 and 2015, respectively. Our primary financing activities consist of the following (in millions):

	Three Months Ended March 31,	
	2016	2015
Net borrowings on Partnership credit facility	$ 129.0	$ 472.0
Net repayments under capital lease obligations	(1.1)	(1.0)
Debt financing costs	(0.2)	(1.8)
Proceeds from issuance of common units	2.1	2.2
Proceeds from issuance of preferred units	724.5	—

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the three months ended March 31, 2016 and 2015 were as follows (in millions):

	Three Months Ended March 31,	
	2016	2015
Common units	$ 127.4	$ 92.3
General partner interest (including incentive distribution rights)	$ 14.4	$ 7.6

We received contributions from Devon of $1.4 million and $2.2 million for the three months ended March 31, 2016 and 2015, respectively, which related to the reimbursement of employee costs. For the three months ended March 31, 2015, we also received a contribution from Devon of $5.7 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 three months ended March 31, 2016 and 2015 were as follows (in millions):

	Three Months Ended March 31,	
	2016	2015
Decrease in drafts payable	$ —	$ (12.7)

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

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

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

Maintenance capital expenditures include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines 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.

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

	2016
Growth Capital Expenditures	
Texas segment	$ 102 - 122
Louisiana segment	40 - 50
Oklahoma segment	83 - 113
Crude and Condensate segment	2 - 7
Corporate segment	71 - 131
Total	$ 298 - 423
Maintenance Capital Expenditures	$ 22.0

Our primary capital projects for 2016 include completing construction of our Lobo II plant and gathering system in our Texas segment, commencing construction of our Marathon joint venture NGL pipeline in our Louisiana segment, developing our TOM assets in our Oklahoma segment and investing in HEP to fund our equity share of its pipeline expansion projects in our Corporate segment. See “Recent Developments” for further details.

We expect to fund the remaining growth capital expenditures from the proceeds of borrowing under our credit facility discussed below and proceeds from other debt and equity sources. We expect to fund our remaining 2016 maintenance capital expenditures from operating cash flows. In 2016, it is possible that not all of the planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. No off-balance sheet arrangements existed as of March 31, 2016.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of March 31, 2016 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2016	2017	2018	2019	2020	Thereafter
Long-term debt obligations	$ 2,662.5	$ —	$ —	$ —	$ 400.0	$ —	$ 2,262.5
Credit facility	543.0	—	—	—	—	543.0	—
Other debt	0.2	0.1	0.1	—	—	—	—
Interest payable on fixed long-term debt obligations	1,843.3	120.0	120.0	120.0	114.6	109.2	1,259.5
Capital lease obligations	14.9	3.1	5.4	3.0	1.6	1.8	—
Operating lease obligations	139.3	13.2	16.5	16.3	11.9	8.7	72.7
Purchase obligations	56.4	56.4	—	—	—	—	—
Delivery contract obligation	58.3	13.5	17.9	17.9	9.0	—	—
Pipeline capacity and deficiency agreements (1)	57.7	8.9	13.8	15.5	11.4	8.1	—
Inactive easement commitment (2)	7.0	1.0	1.0	1.0	1.0	1.0	2.0
Uncertain tax position obligations	1.5	0.5	0.6	0.3	0.1	—	—
Installment payable obligations (3)	500.0	—	250.0	250.0	—	—	—
Total contractual obligations	$ 5,884.1	$ 216.7	$ 425.3	$ 424.0	$ 549.6	$ 671.8	$ 3,596.7

(1) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(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 our partial consideration of the Tall Oak acquisition with balances due on January 7, 2017 and 2018.

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

The interest payable under our credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time. However, given the same borrowing amount and rates in effect at March 31, 2016, the cash obligation for interest expense on our credit facility would be approximately $11.9 million per year or approximately $9.0 million for the remainder of 2016.

Indebtedness

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

	March 31, 2016	December 31, 2015
Partnership credit facility (due 2020), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2016 and December 31, 2015 was 2.2% and 1.8%, respectively	$ 543.0	$ 414.0
Senior unsecured notes (due 2019), net of discount of $0.4 million at March 31, 2016 and $0.4 million at December 31, 2015, which bear interest at the rate of 2.70%	399.6	399.6
Senior unsecured notes (due 2022), including a premium of $18.2 million at March 31, 2016 and $18.9 million at December 31, 2015, which bear interest at the rate of 7.125%	180.7	181.4
Senior unsecured notes (due 2024), net of premium of $2.8 million at March 31, 2016 and $2.9 million at December 31, 2015, which bear interest at the rate of 4.40%	552.8	552.9
Senior unsecured notes (due 2025), net of discount of $1.2 million at March 31, 2016 and $1.2 million at December 31, 2015, which bear interest at the rate of 4.15%	748.8	748.8
Senior unsecured notes (due 2044), net of discount of $0.3 million at March 31, 2016 and $0.2 million at December 31, 2015, which bear interest at the rate of 5.60%	349.7	349.8
Senior unsecured notes (due 2045), net of discount of $6.8 million at March 31, 2016 and $6.9 million at December 31, 2015, which bear interest at the rate of 5.05%	443.2	443.1
Debt issuance cost, net of amortization of $5.5 million at March 31, 2016 and $4.7 million at December 31, 2015	(22.4)	(23.0)
Other debt	0.2	0.2
Debt classified as long-term	$ 3,195.6	$ 3,066.8

Credit Facility. As of March 31, 2016, there were $10.8 million in outstanding letters of credit and $543.0 million of outstanding borrowings under our credit facility, leaving approximately $946.2 million available for future borrowing based on the borrowing capacity of $1.5 billion. Our credit facility will mature on March 6, 2020, unless we request, and the requisite lenders agree, to extend it pursuant to its terms.

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

Recent Accounting Pronouncements

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 $23.0 million of debt issuance costs from “Other Assets, Net” to “Long-term debt” in our accompanying Condensed Consolidated Balance Sheet as of December 31, 2015.

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

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

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

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

In 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 are currently evaluating the impact this standard will have on our condensed consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU 2016-08, *Principal versus Agent Considerations* ("ASU 2016-08"). The new standard retained the guidance that the principal in an arrangement controls a good or service before it is transferred to a customer, and revised and clarified the indicators to evaluate when making this determination. ASU 2016-08 has the same effective date and transition requirements as the new revenue standard, which is effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods. Early application is permitted for annual reporting periods beginning after December 15, 2016. The update will have no impact on our condensed consolidated financial statements or related disclosures.

In March 2016, the FASB issued ASU 2016-07, *Simplifying the Transition to the Equity Method of Accounting* ("ASU 2016-07"). The new standard eliminates the requirement to apply the equity method of accounting retrospectively when a reporting entity obtains significant influence over a previously held investment. Investors should add the cost of acquiring the additional interest in the investee (if any) to the current basis of their previously held interest. ASU 2016-07 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 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 January 2016, the FASB issued ASU 2016-01, *Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities* ("ASU 2016-01"). Under this new standard, the FASB issued new guidance related to accounting for unconsolidated affiliate investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. ASU 2016-01 is effective for annual reporting periods beginning after December 15, 2017 including interim periods within those annual periods. Early adoption is permitted. 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. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and is to be applied retrospectively, with early application permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact the pronouncement will have on our condensed consolidated financial statements and related disclosures.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of federal securities laws. Statements included in this report which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this Quarterly Report on Form 10-Q, the risk factors set forth in Part II, “Item 1A. Risk Factors” of this report may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

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

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

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. 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 CFTC has withdrawn its appeal of the court order vacating the original position limits rule.

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

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements as summarized below. Approximately 92% of our processing margins are from fixed-fee based contracts for the three months ended March 31, 2016.

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

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

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

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

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

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

The following table sets forth certain information related to derivative instruments outstanding atMarch 31, 2016 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by OPIS. The relevant index price for Natural Gas is Henry Hub Gas Daily is as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (in millions)
April 2016 - December 2016	Ethane	415	(MBbls)	$0.2930/gal	Index	$ (1.8)
April 2016 - March 2017	Propane	744	(MBbls)	Index	$0.7434/gal	8.7
April 2016 - March 2017	Normal Butane	181	(MBbls)	Index	$0.5554/gal	0.1
April 2016 - March 2017	Natural Gasoline	90	(MBbls)	Index	$0.8993gal	0.1
April 2016 - March 2017	Natural Gas	12,764	(MMBtu/d)	Index	$2.5574/MMbtu*	0.4
April 2016 - June 2016	Condensate	106	(MBbls)	Index	$38.92/bbl	(0.2)
						$ 7.3

*weighted average

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

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

As of March 31, 2016, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $7.3 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $3.4 million in the net fair value of these contracts as of March 31, 2016.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate credit facility. At March 31, 2016, we had $543.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $5.4 million for the year.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2022, 2024, 2025, 2044 or 2045 as these are fixed-rate obligations. The estimated fair value of our senior unsecured notes was approximately $2,085.8 million as of March 31, 2016, based on market prices of similar debt at March 31, 2016. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in approximately a $153.2 million decrease in fair value of our senior unsecured notes at March 31, 2016.

Item 4. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of EnLink Midstream GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (March 31, 2016), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended March 31, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. *Legal Proceedings*

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

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

Item 1A. ***Risk Factors***

Information about risk factors does not differ materially from that set forth in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

Item 6. ***Exhibits***

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

2.1	**	—	TOM-STACK Securities Purchase Agreement, dated as of December 6, 2015, among Tall Oak Midstream, LLC, FE-STACK, LLC, TOM-STACK Holdings, LLC, TOM-STACK, LLC, EnLink TOM Holdings, LP and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
2.2	**	—	TOMPC Securities Purchase Agreement, dated as of December 6, 2015, among TOMPC LLC, Tall Oak Midstream, LLC, EnLink TOM Holdings, LP, and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
3.1		—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2		—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, file No. 000-50067).
3.3		—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
3.4		—	Eighth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
3.5		—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.6		—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to our Registration Statement on Form S-3, file No. 333-194465).
3.7		—	Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014).
3.8		—	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
4.1		—	Registration Rights Agreement, dated as of January 7, 2016, by and between EnLink Midstream Partners, LP and Enfield Holdings, L.P. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 7, 2016, file No. 001-36340).
10.1		—	Board Representation Agreement, dated as of January 7, 2016, by and among EnLink Midstream GP, LLC, EnLink Midstream Partners, LP, EnLink Midstream, Inc. and TPG VII Management, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 7, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
10.2	†	—	EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 3, 2016, filed with the Commission on March 9, 2016, file No. 001-36340).
10.3	*†	—	Form of Performance Unit Agreement made under the GP Plan

10.4	*†	—	Form of Performance Unit Agreement made under the LLC Plan.
31.1	*	—	Certification of the Principal Executive Officer.
31.2	*	—	Certification of the Principal Financial Officer.
32.1	*	—	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101	*	—	The following financial information from EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets as of March 31, 2016 and December 31, 2015, (ii) Condensed Consolidated Statements of Operations for the three months ended March 31, 2016 and 2015, (iii) Consolidated Statements of Changes in Partners' Equity for the three months ended March 31, 2016, (iv) Consolidated Statements of Cash Flows for the three months ended March 31, 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.

† As required by Item 15(a)(3), this Exhibit is identified as a compensatory benefit plan or arrangement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EnLink Midstream Partners, LP

By: EnLink Midstream GP, LLC,
its General Partner

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

May 4, 2016

Exhibit 10.3

PERFORMANCE UNIT AGREEMENT

THIS PERFORMANCE UNIT AGREEMENT (this "***Agreement***") is entered into by and between EnLink Midstream GP, LLC, a Delaware limited liability company (the "***Company***"), and _________________ ("***Participant***") as of the Grant Date.

WITNESSETH:

WHEREAS, the EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated March 7, 2014 (the "***Plan***"), was adopted by the Company for the benefit of certain employees and consultants of the Company or its Affiliates, and non-employee directors of the Company; and

WHEREAS, the Committee is responsible for granting Awards in accordance with the Plan, which Awards shall be subject to such terms and conditions as the Committee shall determine pursuant to the Plan; and

WHEREAS, Participant is eligible to participate in the Plan and the Committee has authorized the grant to Participant of the "***Subject Award***" (as defined in Section 2 of this Agreement), which is intended to constitute performance-based compensation, and which shall be subject to certain restrictions pursuant to the Plan and upon the terms set forth herein.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Company and Participant hereby agree as follows:

1. Definitions. Capitalized terms used herein and not otherwise defined herein shall have the meaning ascribed to them in the Plan.

"***Good Reason***" means any of the following, without Participant's consent: (i) a material reduction in Participant's base annual salary; (ii) a material adverse change in Participant's authority, duties or responsibilities; or (iii) the Company requires Participant to move his or her principal place of employment to a location that is 30 or more miles from his or her current place of employment and the new location is farther from his or her primary residence. From and after the occurrence of a Change of Control that occurs following the date hereof, Good Reason shall also include any material breach of this Agreement by the Company (or any successor thereof, as applicable). For purposes of this definition, no act or failure to act on the Company's part shall be considered a "Good Reason" unless (x) Participant has given the Company written notice of such act or failure to act within 30 days thereof, (y) the Company fails to remedy such act or failure to act within 30 days of its receipt of such notice, and (z) Participant terminates his or her employment with the Company within 60 days following the Company's receipt of written notice.

"***Grant Date***" means _______.

"***Performance Goal***" means the Performance Goal as set forth in Schedule A to this Agreement.

"***Performance Period***" means the period defined in Schedule A to this Agreement for purposes of determining attainment of the Performance Goal.

"***Prorated Amount***" means a number equal to the total number of outstanding Restricted Incentive Units granted hereunder multiplied by a fraction (i) the numerator of which is the number of days that elapse from the commencement of the Performance Period to the date of the Qualifying Termination and (ii) the denominator of which is the full number of days of the Performance Period.

"***Qualifying Termination***" means Participant's employment or service with the Company or its Affiliates is terminated due to (i) Participant's retirement with the approval of the Chief Executive Officer of the Company on or after reaching age 60, (ii) an involuntary termination of Participant by the Company for reasons other than Cause, or (iii) a termination by Participant for Good Reason.

"***Vesting Date***" means the date on which the Performance Period ends as set forth in Schedule A to this Agreement.

2. Performance Unit Award. On the terms and conditions and subject to the restrictions, including forfeiture, hereinafter set forth, the Company hereby grants to Participant, and Participant hereby accepts, an award of _______ Restricted Incentive

Units (the "***Subject Award***"). The Restricted Incentive Units granted hereunder shall be evidenced by the Committee in a book entry or in such other manner as the Committee may determine.

3. Vesting/Forfeiture.

(a) The Restricted Incentive Units that comprise the Subject Award shall be subject to a Performance Period that shall terminate on the Vesting Date based on the attainment and certification of the Performance Goal as described Schedule A; provided that Participant is in the continuous service of the Company or its Affiliates until such Vesting Date.

(b) The Restricted Incentive Units shall be forfeited to the Company at no cost to the Company if Participant's employment or service with the Company or its Affiliates terminates prior to the termination of the Performance Period applicable to such Restricted Incentive Units; *provided, however*:

(i) if a Qualifying Termination occurs during the Performance Period and prior to the occurrence of a Change of Control that occurs following the date hereof, a Prorated Amount of the Restricted Incentive Units shall remain eligible for vesting on the Vesting Date, based on the attainment and certification of the Performance Goal as described Schedule A;

(ii) if a Change of Control occurs following the date hereof, the Restricted Incentive Units shall become fully vested at the Target amount and the Performance Period shall terminate; or

(iii) if, during the Performance Period, the Participant dies or he or she becomes disabled and qualified to receive benefits under the Company's long-term disability plan, the Restricted Incentive Units shall become fully vested at the Target amount and the Performance Period shall terminate.

Notwithstanding the foregoing, to the extent the Subject Award is subject to Section 409A, in no event shall any Units be delivered when Participant becomes disabled and qualified to receive benefits under the Company's long-term disability plan unless Participant incurs a "disability" within the meaning of Treas. Reg. Section 1.409A-3(i)(4).

Notwithstanding anything herein to the contrary, if, at the time of a Participant's termination of employment or service with the Company or its Affiliates, such Participant is a "specified employee" (as defined in Section 409A of the Code), and the deferral of the commencement of any amount of the payments or benefits otherwise payable pursuant to the Plan is necessary in order to prevent any accelerated or additional tax under Section 409A of the Code, then, to the extent permitted by Section 409A of the Code, such payments or benefits hereunder (without any reduction in the payments or benefits ultimately paid or provided to the Participant) will be deferred until the earlier to occur of (i) the Participant's death or (ii) the first business day that is six (6) months following the Participant's termination of employment or service with the Company or its Affiliates, provided that amounts which qualify for the separation pay plan exemption under Treasury Regulation §1.409A-1(b)(9)(v)(D) and do not exceed the limits set forth in Section 402(g)(1)(B) of the Code in the year of such termination shall be payable immediately upon termination. Any payments or benefits deferred due to the requirements of this paragraph will be paid in a lump sum (without interest) to the Participant on the earliest to occur of (i) or (ii) in the immediately preceding sentence.

(c) As soon as reasonably practicable following the close of the Performance Period, the Committee shall determine and certify the extent to which (i) the Performance Goal as described on Schedule A is attained and (ii) the Restricted Incentive Units granted hereunder shall be vested, if at all. Such certification shall be final, conclusive and binding on Participant, and on all other persons, to the maximum extent permitted by law. As soon as reasonably practicable thereafter, Units representing the number of vested Restricted Incentive Units, if any, shall be delivered, free of all such restrictions, to Participant or Participant's beneficiary or estate, as the case may be, it being understood that the entry on the transfer agent's books or the delivery of the certificate(s) with respect to such Units shall constitute delivery of such Units for purposes of this Agreement. Notwithstanding anything contained herein to the contrary, in no event shall such Units be delivered to Participant later than (i) the end of the calendar year in which vesting occurs, or, if later, (ii) the 15th day of the third calendar month following the date on which vesting occurs.

(d) Notwithstanding anything contained herein to the contrary, in no event shall Participant have any right to vote any, or to exercise any other rights, powers and privileges of a holder of the Units with respect to such Restricted Incentive Units until such time that (i) the Performance Period applicable to such Restricted Incentive Units or a portion thereof shall have expired (and all other conditions to payment with respect thereto have been fulfilled), (ii) such Restricted Incentive Units are converted into the right to receive Units, and (iii) such Units are delivered to Participant.

4. Distribution Equivalent Payment Rights. Subject to the following, the Subject Award granted hereunder includes a tandem award of Distribution Equivalent Rights with respect to each applicable Restricted Incentive Unit that shall entitle Participant to

receive cash payments equal to the cash distributions made by the Partnership (on a per Unit basis) in respect of its outstanding Units generally ("***General Distributions***"); provided that such cash payments ("***Distribution Equivalent Payments***") shall be credited to a bookkeeping account established on the records of the Partnership for Participant and will vest and be paid to or on behalf of Participant at the same time, and subject to the same conditions, as are applicable to the vesting of the underlying Restricted Incentive Units. Accordingly, Distribution Equivalent Payments shall be forfeited to the extent that the underlying Restricted Incentive Units do not vest, are forfeited or are otherwise cancelled. No interest shall be credited on any Distribution Equivalent Payments.

5. Taxes.

(a) **REPRESENTATION. PARTICIPANT REPRESENTS THAT PARTICIPANT IS NOT RELYING ON THE COMPANY OR ITS AFFILIATES FOR ANY TAX ADVICE IN CONNECTION WITH THE RESTRICTED INCENTIVE UNITS AND THAT PARTICIPANT HAS BEEN, OR IS OTHERWISE HEREBY, ADVISED TO CONSULT WITH ITS OWN TAX ADVISOR WITH RESPECT TO THE AWARD OF RESTRICTED INCENTIVE UNITS UNDER THIS AGREEMENT.**

(b) Withholding Matters.

(i) Participant shall pay to the Company or its Affiliates, or make arrangements satisfactory to the Company or its Affiliates regarding payment of, any federal, state or local taxes of any kind required by law to be withheld with respect to (x) Distribution Equivalent Payments described in Section 4 of this Agreement that are received due to the grant of the Restricted Incentive Units hereunder, and (y) the vesting of the Restricted Incentive Units (in which case arrangements will be made no later than the time Units are delivered, if at all, pursuant to Section 3(c) herein).

(ii) Participant shall, to the extent permitted by law, have the right to deliver to the Company or its Affiliates Units to which Participant shall be entitled upon the vesting of the Restricted Incentive Units (or other unrestricted Units owned by Participant) or to deliver to the Company or its Affiliates Units that Participant has previously acquired, in each case valued at the Fair Market Value of such Units at the time of such delivery to the Company or its Affiliates, to satisfy the obligation of Participant under Section 5(b)(i) of this Agreement; *provided*, *however*, that, in no event shall the Fair Market Value of such Units exceed the minimum statutory withholding requirements.

(iii) Any provision of this Agreement to the contrary notwithstanding, if Participant does not otherwise satisfy the obligation of Participant under Section 5(b)(i) of this Agreement, then the Company and its Affiliates shall, to the extent permitted by law, have the right to deduct from any payments of any kind otherwise due from the Company or its Affiliates to or with respect to Participant, whether or not pursuant to this Agreement or the Plan and regardless of the form of payment, any federal, state or local taxes of any kind required by law to be withheld with respect to any Distribution Equivalent Payments or Restricted Incentive Units hereunder.

6 . Non-Assignability. The Subject Award is not assignable or transferable by Participant, and, unless and until Units with respect to Restricted Incentive Units are delivered to Participant upon vesting, such Restricted Incentive Units shall not be assigned, alienated, pledged, attached sold or otherwise transferred or encumbered by Participant in any manner.

7. Legend. In the event any Units are delivered to Participant in connection with the vesting of any of the Restricted Incentive Units granted hereunder, the Committee, in its discretion, may cause the certificate(s) representing such Units to bear an appropriate legend referring to any conditions and/or restrictions with respect to such Units.

8. Entirety and Modification. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any and all prior agreements, whether written or oral, between such parties relating to such subject matter. Subject to Section 7(b) of the Plan, no modification, alteration, amendment or supplement to this Agreement shall be valid or effective unless the same is in writing and signed by the party against whom it is sought to be enforced.

9 . Severability. If any provision of this Agreement is held to be unenforceable, this Agreement shall be considered divisible, and such provision shall be deemed inoperative to the extent it is unenforceable, and in all other respects this Agreement shall remain in full force and effect; *provided, however*, that if any such provision may be made enforceable by limitation thereof, then such provision shall be deemed to be so limited and shall be enforceable to the maximum extent permitted by applicable law.

10. Gender. Words used in this Agreement which refer to Participant and denote the male gender shall also be deemed to include the female gender or the neuter gender when appropriate.

11. Employment or Service. Nothing in this Agreement shall confer upon Participant any right to continue in the employ or service of the Company or its Affiliates, nor shall this Agreement interfere in any manner with the right of the Company or its Affiliates to terminate the employment or service of Participant with or without Cause at any time.

12 Incorporation of Plan Provisions. This Agreement is made pursuant to the Plan and is subject to all of the terms and provisions of the Plan as if the same were fully set forth herein. In the event that any provision of this Agreement conflicts with the Plan, the provisions of the Plan shall control. Participant acknowledges receipt of a copy of the Plan and agrees that all decisions under and interpretations of the Plan by the Committee shall be final, binding and conclusive upon Participant.

13. Headings. The headings of the various sections and subsections of this Agreement have been inserted for convenient reference only and shall not be construed to enlarge, diminish or otherwise change the express provisions hereof.

14. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the state of Delaware (regardless of the laws that might otherwise govern under applicable Delaware principles of conflicts of law).

15. Counterparts. This Agreement may be signed in counterparts, each of which shall be deemed an original and all of which shall constitute one and the same agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the Grant Date.

ENLINK MIDSTREAM GP, LLC

____
Barry E. Davis
President and Chief Executive Officer

PARTICIPANT:

Name:

You must accept this grant and the terms of this Agreement in order to receive it. To accept this grant, complete the Grant Acceptance Process at the website of UBS: (www.ubs.com/onesource/ENLK)

SCHEDULE A
PERFORMANCE GOAL, PERFORMANCE PERIOD, AND PAYOUT AMOUNTS

1. Performance Period. The maximum number of Restricted Incentive Units, which can vest pursuant to the Subject Award shall be calculated based on the Performance Goal over a period (the "***Performance Period***") that begins on _______ and ends on _______ (the "***Vesting Date***").

2. Performance Goal. The Performance Goal is based on total shareholder return ("***TSR***"), which shall be the rate of return a holder of a common equity security of a company would receive through common equity security price changes and the assumed reinvestment of dividends / distributions over the Performance Period. Vesting will be based on the ranking of the average of the TSR of the Partnership and the TSR of EnLink Midstream, LLC (the "***LLC***" and, together with the Partnership, "***EnLink***") relative to the TSR ranking of the Peer Companies (identified in Sections 3(b) and (c) below). At the end of the Performance Period, the TSR for the Partnership, for the LLC and for each Peer Company, shall be determined pursuant to the following formula:

TSR = (Closing Average Value - Opening Average Value) + Reinvested Dividends / Opening Average Value*

*The result shall be rounded to the nearest hundredth of one percent (.01%).

(a) The term "***Closing Average Value***" means the average value of the common equity security on the relevant United States stock market (NYSE or NASDAQ) for the 30 trading days ending on the last day of the Performance Period, which shall be calculated as follows: (i) determine the closing price of the common equity security on each trading date during 30-day period and (ii) average the amounts so determined for the 30-day period.

(b) The term "***Opening Average Value***" means the average value of the common equity security on the relevant United States stock market (NYSE or NASDAQ) for the 30 trading days preceding the start of the Performance Period, which shall be calculated as follows: (i) determine the closing price of the common equity security on each trading date during the 30-day period and (ii) average the amounts so determined for the 30-day period.

(c) "***Reinvested Dividends***" shall be calculated by multiplying (i) the aggregate number of common equity securities (including fractional units thereof) that could have been purchased during the Performance Period had each cash dividend or distribution paid on a single common equity security during that period been immediately reinvested in additional common equity securities (or fractional units thereof) at the closing selling price per common equity security on the applicable dividend or distribution payment date by (ii) the average daily closing price per common equity security on the relevant United States stock market (NYSE or NASDAQ) calculated for the duration of the Performance Period following the dividend or distribution payment date.

(d) Each of the foregoing amounts shall be equitably adjusted for stock / unit splits, stock dividends or unit distributions, recapitalizations and other similar events affecting the common equity securities in question without the issuer's receipt of consideration.

3. Vesting Schedule. The Restricted Incentive Units shall vest pursuant to the Agreement based on EnLink's relative TSR ranking in respect of the Performance Period as compared to the TSR ranking of the Peer Companies, in accordance with the following schedule:

Performance Level	**EnLink's Achieved TSR Percentile Position Relative to AMZ Peers***	**Associated Individual Payout Level (expressed as a percentage of the Subject Award)**
Below Threshold	Less than 25%	0%
Threshold	Equal to 25%	50%
Target	Equal to 50%	100%
Maximum	Greater than or Equal to 75%	200%

* If EnLink's achieved TSR percentile position is between the Threshold and Target performance levels or if EnLink's achieved TSR percentile position is between the Target and Maximum performance levels (and EnLink's TSR is positive for the Performance Period), then the associated individual payout level will be interpolated on a linear basis.

(a) If EnLink's final TSR value is equal to the TSR value of a Peer Company, the Committee shall assign EnLink the higher ranking.

(b) The Peer Companies are the companies that comprise the Alerian MLP Index for Master Limited Partnerships (AMZ) as of the Grant Date, which are set forth on Schedule B to this Agreement, it being understood that in no event shall the Peer Companies include the LLC or the Partnership.

(c) The Peer Companies will be subject to change as follows:

(i) In the event of a merger, acquisition or business combination transaction of a Peer Company, in which the Peer Company is the surviving entity and remains publicly traded, the surviving entity shall remain a Peer Company. Any entity involved in the transaction that is not the surviving company shall no longer be a Peer Company.

(ii) If a Peer Company ceases to be a publicly traded company at any time during the Performance Period, due to bankruptcy, delisting or any other reason other than those set forth in clause (i) above, such company shall remain a Peer Company but shall be deemed to have a TSR of negative 100% (-100%).

4. General Vesting Terms. Any fractional Restricted Incentive Units resulting from the vesting of the Restricted Incentive Units in accordance with the Agreement shall be rounded down to the nearest whole number. Any portion of the Restricted Incentive Units that does not vest as of the end of the Performance Period shall be forfeited as of the end of the Performance Period.

SCHEDULE B
PEER COMPANIES

[to be completed at time of grant]

Exhibit 10.4

PERFORMANCE UNIT AGREEMENT

THIS PERFORMANCE UNIT AGREEMENT (this "***Agreement***") is entered into by and between EnLink Midstream, LLC, a Delaware limited liability company (the "***Company***"), and _________________ ("***Participant***") as of the Grant Date.

WITNESSETH:

WHEREAS, the EnLink Midstream, LLC 2014 Long-Term Incentive Plan was adopted by the Company, effective February 5, 2014 (the "***Plan***"), for the benefit of certain employees and consultants of the Company or its Affiliates, and non-employee directors of EnLink Midstream Manager, LLC, the managing member of the Company; and

WHEREAS, a committee (the "***Special Committee***") has been designated to administer Awards that are intended to constitute qualified performance-based compensation ("***Qualified Awards***") under Section 162(m) of the Internal Revenue Code of 1986, as amended (the "***Code***"), which Qualified Awards shall be subject to such terms and conditions as the Special Committee shall determine pursuant to the Plan;

WHEREAS, the Special Committee is responsible for granting Qualified Awards in accordance with the Plan; and

WHEREAS, Participant is eligible to participate in the Plan and the Special Committee has authorized the grant to Participant of the "***Subject Award***" (as defined in Section 2 of this Agreement), which is intended to constitute a Qualified Award, and which shall be subject to certain restrictions pursuant to the Plan and upon the terms set forth herein.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Company and Participant hereby agree as follows:

1. Definitions. Capitalized terms used herein and not otherwise defined herein shall have the meaning ascribed to them in the Plan.

"***Good Reason***" means any of the following, without Participant's consent: (i) a material reduction in Participant's base annual salary; (ii) a material adverse change in Participant's authority, duties or responsibilities; or (iii) the Company requires Participant to move his or her principal place of employment to a location that is 30 or more miles from his or her current place of employment and the new location is farther from his or her primary residence. From and after the occurrence of a Change of Control that occurs following the date hereof, Good Reason shall also include any material breach of this Agreement by the Company (or any successor thereof, as applicable). For purposes of this definition, no act or failure to act on the Company's part shall be considered a "Good Reason" unless (x) Participant has given the Company written notice of such act or failure to act within 30 days thereof, (y) the Company fails to remedy such act or failure to act within 30 days of its receipt of such notice, and (z) Participant terminates his or her employment with the Company within 60 days following the Company's receipt of written notice.

"***Grant Date***" means _____.

"***Performance Goal***" means the Performance Goal as set forth in Schedule A to this Agreement.

"***Performance Period***" means the period defined in Schedule A to this Agreement for purposes of determining attainment of the Performance Goal.

"***Prorated Amount***" means a number equal to the total number of outstanding Restricted Incentive Units granted hereunder multiplied by a fraction (i) the numerator of which is the number of days that elapse from the commencement of the Performance Period to the date of the Qualifying Termination and (ii) the denominator of which is the full number of days of the Performance Period.

"***Qualifying Termination***" means Participant's employment or service with the Company or its Affiliates is terminated due to (i) Participant's retirement with the approval of the Chief Executive Officer of EnLink Midstream Manager, LLC on or after reaching age 60, (ii) an involuntary termination of Participant by the Company for reasons other than Cause, or (iii) a termination by Participant for Good Reason.

"***Vesting Date***" means the date on which the Performance Period ends as set forth in Schedule A to this Agreement.

2 . Performance Unit Award. On the terms and conditions and subject to the restrictions, including forfeiture, hereinafter set forth, the Company hereby grants to Participant, and Participant hereby accepts, an award of _____ Restricted Incentive Units (the "***Subject Award***"). The Restricted Incentive Units granted hereunder shall be evidenced by the Special Committee in a book entry or in such other manner as the Special Committee may determine.

3. Vesting/Forfeiture.

(a) The Restricted Incentive Units that comprise the Subject Award shall be subject to a Performance Period that shall terminate on the Vesting Date based on the attainment and certification of the Performance Goal as described Schedule A; provided that Participant is in the continuous service of the Company or its Affiliates until such Vesting Date.

(b) The Restricted Incentive Units shall be forfeited to the Company at no cost to the Company if Participant's employment or service with the Company or its Affiliates terminates prior to the termination of the Performance Period applicable to such Restricted Incentive Units; *provided, however*:

(i) if a Qualifying Termination occurs during the Performance Period and prior to the occurrence of a Change of Control that occurs following the date hereof, a Prorated Amount of the Restricted Incentive Units shall remain eligible for vesting on the Vesting Date, based on the attainment and certification of the Performance Goal as described Schedule A;

(ii) if a Change of Control occurs following the date hereof, the Restricted Incentive Units shall become fully vested at the Target amount and the Performance Period shall terminate; or

(iii) if, during the Performance Period, the Participant dies or he or she becomes disabled and qualified to receive benefits under the Company's long-term disability plan, the Restricted Incentive Units shall become fully vested at the Target amount and the Performance Period shall terminate.

Notwithstanding the foregoing, to the extent the Subject Award is subject to Section 409A, in no event shall any Units be delivered when Participant becomes disabled and qualified to receive benefits under the Company's long-term disability plan unless Participant incurs a "disability" within the meaning of Treas. Reg. Section 1.409A-3(i)(4).

Notwithstanding anything herein to the contrary, if, at the time of a Participant's termination of employment or service with the Company or its Affiliates, such Participant is a "specified employee" (as defined in Section 409A of the Code), and the deferral of the commencement of any amount of the payments or benefits otherwise payable pursuant to the Plan is necessary in order to prevent any accelerated or additional tax under Section 409A of the Code, then, to the extent permitted by Section 409A of the Code, such payments or benefits hereunder (without any reduction in the payments or benefits ultimately paid or provided to the Participant) will be deferred until the earlier to occur of (i) the Participant's death or (ii) the first business day that is six (6) months following the Participant's termination of employment or service with the Company or its Affiliates, provided that amounts which qualify for the separation pay plan exemption under Treasury Regulation §1.409A-1(b)(9)(v)(D) and do not exceed the limits set forth in Section 402(g)(1)(B) of the Code in the year of such termination shall be payable immediately upon termination. Any payments or benefits deferred due to the requirements of this paragraph will be paid in a lump sum (without interest) to the Participant on the earliest to occur of (i) or (ii) in the immediately preceding sentence.

(c) As soon as reasonably practicable following the close of the Performance Period, the Special Committee shall determine and certify the extent to which (i) the Performance Goal as described on Schedule A is attained and (ii) the Restricted Incentive Units granted hereunder shall be vested, if at all. Such certification shall be final, conclusive and binding on Participant, and on all other persons, to the maximum extent permitted by law. As soon as reasonably practicable thereafter, Units representing the number of vested Restricted Incentive Units, if any, shall be delivered, free of all such restrictions, to Participant or Participant's beneficiary or estate, as the case may be, it being understood that the entry on the transfer agent's books or the delivery of the certificate(s) with respect to such Units shall constitute delivery of such Units for purposes of this Agreement. Notwithstanding anything contained herein to the contrary, in no event shall such Units be delivered to Participant later than (i) the end of the calendar year in which vesting occurs, or, if later, (ii) the 15th day of the third calendar month following the date on which vesting occurs.

(d) Notwithstanding anything contained herein to the contrary, in no event shall Participant have any right to vote any, or to exercise any other rights, powers and privileges of a holder of the Units with respect to such Restricted Incentive Units until such time that (i) the Performance Period applicable to such Restricted Incentive Units or a portion thereof shall have expired (and all other conditions to payment with respect thereto have been fulfilled), (ii) such Restricted Incentive Units are converted into the right to receive Units, and (iii) such Units are delivered to Participant.

4. <u>Distribution Equivalent Payment Rights</u>. Subject to the following, the Subject Award granted hereunder includes a tandem award of Distribution Equivalent Rights with respect to each applicable Restricted Incentive Unit that shall entitle Participant to receive cash payments equal to the cash distributions made by the Company (on a per Unit basis) in respect of its outstanding Units generally ("***General Distributions***"); provided that such cash payments ("***Distribution Equivalent Payments***") shall be credited to a bookkeeping account established on the records of the Company for Participant and will vest and be paid to or on behalf of Participant at the same time, and subject to the same conditions, as are applicable to the vesting of the underlying Restricted Incentive Units. Accordingly, Distribution Equivalent Payments shall be forfeited to the extent that the underlying Restricted Incentive Units do not vest, are forfeited or are otherwise cancelled. No interest shall be credited on any Distribution Equivalent Payments.

5. <u>Taxes</u>.

(a) **<u>REPRESENTATION</u>. PARTICIPANT REPRESENTS THAT PARTICIPANT IS NOT RELYING ON THE COMPANY OR ITS AFFILIATES FOR ANY TAX ADVICE IN CONNECTION WITH THE RESTRICTED INCENTIVE UNITS AND THAT PARTICIPANT HAS BEEN, OR IS OTHERWISE HEREBY, ADVISED TO CONSULT WITH ITS OWN TAX ADVISOR WITH RESPECT TO THE AWARD OF RESTRICTED INCENTIVE UNITS UNDER THIS AGREEMENT.**

(b) <u>Withholding Matters</u>.

(i) Participant shall pay to the Company or its Affiliates, or make arrangements satisfactory to the Company or its Affiliates regarding payment of, any federal, state or local taxes of any kind required by law to be withheld with respect to (x) Distribution Equivalent Payments described in Section 4 of this Agreement that are received due to the grant of the Restricted Incentive Units hereunder, and (y) the vesting of the Restricted Incentive Units (in which case arrangements will be made no later than the time Units are delivered, if at all, pursuant to Section 3(c) herein).

(ii) Participant shall, to the extent permitted by law, have the right to deliver to the Company or its Affiliates Units to which Participant shall be entitled upon the vesting of the Restricted Incentive Units (or other unrestricted Units owned by Participant) or to deliver to the Company or its Affiliates Units that Participant has previously acquired, in each case valued at the Fair Market Value of such Units at the time of such delivery to the Company or its Affiliates, to satisfy the obligation of Participant under Section 5(b)(i) of this Agreement; *provided*, *however*, that, in no event shall the Fair Market Value of such Units exceed the minimum statutory withholding requirements.

(iii) Any provision of this Agreement to the contrary notwithstanding, if Participant does not otherwise satisfy the obligation of Participant under Section 5(b)(i) of this Agreement, then the Company and its Affiliates shall, to the extent permitted by law, have the right to deduct from any payments of any kind otherwise due from the Company or its Affiliates to or with respect to Participant, whether or not pursuant to this Agreement or the Plan and regardless of the form of payment, any federal, state or local taxes of any kind required by law to be withheld with respect to any Distribution Equivalent Payments or Restricted Incentive Units hereunder.

6. <u>Non-Assignability</u>. The Subject Award is not assignable or transferable by Participant, and, unless and until Units with respect to Restricted Incentive Units are delivered to Participant upon vesting, such Restricted Incentive Units shall not be assigned, alienated, pledged, attached sold or otherwise transferred or encumbered by Participant in any manner.

7. <u>Legend</u>. In the event any Units are delivered to Participant in connection with the vesting of any of the Restricted Incentive Units granted hereunder, the Special Committee, in its discretion, may cause the certificate(s) representing such Units to bear an appropriate legend referring to any conditions and/or restrictions with respect to such Units.

8. <u>Entirety and Modification</u>. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any and all prior agreements, whether written or oral, between such parties relating to such subject matter. Subject to Section 15.2 of the Plan, no modification, alteration, amendment or supplement to this Agreement shall be valid or effective unless the same is in writing and signed by the party against whom it is sought to be enforced.

9 . Severability. If any provision of this Agreement is held to be unenforceable, this Agreement shall be considered divisible, and such provision shall be deemed inoperative to the extent it is unenforceable, and in all other respects this Agreement shall remain in full force and effect; *provided, however*, that if any such provision may be made enforceable by limitation thereof, then such provision shall be deemed to be so limited and shall be enforceable to the maximum extent permitted by applicable law.

10. Gender. Words used in this Agreement which refer to Participant and denote the male gender shall also be deemed to include the female gender or the neuter gender when appropriate.

11. Employment or Service. Nothing in this Agreement shall confer upon Participant any right to continue in the employ or service of the Company or its Affiliates, nor shall this Agreement interfere in any manner with the right of the Company or its Affiliates to terminate the employment or service of Participant with or without Cause at any time.

12 Incorporation of Plan Provisions. This Agreement is made pursuant to the Plan and is subject to all of the terms and provisions of the Plan as if the same were fully set forth herein. In the event that any provision of this Agreement conflicts with the Plan, the provisions of the Plan shall control. Participant acknowledges receipt of a copy of the Plan and agrees that all decisions under and interpretations of the Plan by the Special Committee shall be final, binding and conclusive upon Participant.

13. Headings. The headings of the various sections and subsections of this Agreement have been inserted for convenient reference only and shall not be construed to enlarge, diminish or otherwise change the express provisions hereof.

14. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the state of Delaware (regardless of the laws that might otherwise govern under applicable Delaware principles of conflicts of law).

15. Counterparts. This Agreement may be signed in counterparts, each of which shall be deemed an original and all of which shall constitute one and the same agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the Grant Date.

ENLINK MIDSTREAM, LLC
By: EnLink Midstream Manager, LLC

____
Barry E. Davis
President and Chief Executive Officer

PARTICIPANT:

Name:

You must accept this grant and the terms of this Agreement in order to receive it. To accept this grant, complete the Grant Acceptance Process at the website of UBS: (www.ubs.com/onesource/ENLC)

SCHEDULE A
PERFORMANCE GOAL, PERFORMANCE PERIOD, AND PAYOUT AMOUNTS

1. Performance Period. The maximum number of Restricted Incentive Units, which can vest pursuant to the Subject Award shall be calculated based on the Performance Goal over a period (the "***Performance Period***") that begins on _____ and ends on _____ (the "***Vesting Date***").

2. Performance Goal. The Performance Goal is based on total shareholder return ("***TSR***"), which shall be the rate of return a holder of a common equity security of a company would receive through common equity security price changes and the assumed reinvestment of dividends / distributions over the Performance Period. Vesting will be based on the ranking of the average of the TSR of the Company and the TSR of EnLink Midstream Partners, LP (the "***Partnership***" and, together with the Company, "***EnLink***") relative to the TSR ranking of the Peer Companies (identified in Sections 3(b) and (c) below). At the end of the Performance Period, the TSR for the Company, for the Partnership and for each Peer Company, shall be determined pursuant to the following formula:

TSR = (Closing Average Value - Opening Average Value) + Reinvested Dividends / Opening Average Value*

*The result shall be rounded to the nearest hundredth of one percent (.01%).

(a) The term "***Closing Average Value***" means the average value of the common equity security on the relevant United States stock market (NYSE or NASDAQ) for the 30 trading days ending on the last day of the Performance Period, which shall be calculated as follows: (i) determine the closing price of the common equity security on each trading date during 30-day period and (ii) average the amounts so determined for the 30-day period.

(b) The term "***Opening Average Value***" means the average value of the common equity security on the relevant United States stock market (NYSE or NASDAQ) for the 30 trading days preceding the start of the Performance Period, which shall be calculated as follows: (i) determine the closing price of the common equity security on each trading date during the 30-day period and (ii) average the amounts so determined for the 30-day period.

(c) "***Reinvested Dividends***" shall be calculated by multiplying (i) the aggregate number of common equity securities (including fractional units thereof) that could have been purchased during the Performance Period had each cash dividend or distribution paid on a single common equity security during that period been immediately reinvested in additional common equity securities (or fractional units thereof) at the closing selling price per common equity security on the applicable dividend or distribution payment date by (ii) the average daily closing price per common equity security on the relevant United States stock market (NYSE or NASDAQ) calculated for the duration of the Performance Period following the dividend or distribution payment date.

(d) Each of the foregoing amounts shall be equitably adjusted for stock / unit splits, stock dividends or unit distributions, recapitalizations and other similar events affecting the common equity securities in question without the issuer's receipt of consideration.

3. Vesting Schedule. The Restricted Incentive Units shall vest pursuant to the Agreement based on EnLink's relative TSR ranking in respect of the Performance Period as compared to the TSR ranking of the Peer Companies, in accordance with the following schedule:

Performance Level	**EnLink's Achieved TSR Percentile Position Relative to AMZ Peers***	**Associated Individual Payout Level (expressed as a percentage of the Subject Award)**
Below Threshold	Less than 25%	0%
Threshold	Equal to 25%	50%
Target	Equal to 50%	100%
Maximum	Greater than or Equal to 75%	200%

* If EnLink's achieved TSR percentile position is between the Threshold and Target performance levels or if EnLink's achieved TSR percentile position is between the Target and Maximum performance levels (and EnLink's TSR is positive for the Performance Period), then the associated individual payout level will be interpolated on a linear basis.

(a) If EnLink's final TSR value is equal to the TSR value of a Peer Company, the Special Committee shall assign EnLink the higher ranking.

(b) The Peer Companies are the companies that comprise the Alerian MLP Index for Master Limited Partnerships (AMZ) as of the Grant Date, which are set forth on Schedule B to this Agreement, it being understood that in no event shall the Peer Companies include the Company or the Partnership.

(c) The Peer Companies will be subject to change as follows:

(i) In the event of a merger, acquisition or business combination transaction of a Peer Company, in which the Peer Company is the surviving entity and remains publicly traded, the surviving entity shall remain a Peer Company. Any entity involved in the transaction that is not the surviving company shall no longer be a Peer Company.

(ii) If a Peer Company ceases to be a publicly traded company at any time during the Performance Period, due to bankruptcy, delisting or any other reason other than those set forth in clause (i) above, such company shall remain a Peer Company but shall be deemed to have a TSR of negative 100% (-100%).

4. General Vesting Terms. Any fractional Restricted Incentive Units resulting from the vesting of the Restricted Incentive Units in accordance with the Agreement shall be rounded down to the nearest whole number. Any portion of the Restricted Incentive Units that does not vest as of the end of the Performance Period shall be forfeited as of the end of the Performance Period.

SCHEDULE B
PEER COMPANIES

[to be completed at time of grant]

Exhibit 31.1

CERTIFICATIONS

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

1. I have reviewed this quarterly report on Form 10-Q of EnLink Midstream Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BARRY E. DAVIS

BARRY E. DAVIS
President and Chief Executive Officer
(principal executive officer)

Date: May 4, 2016

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Executive Vice President and Chief Financial Officer of EnLink Midstream GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of EnLink Midstream Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: May 4, 2016

Exhibit 32.1

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

In connection with the Quarterly Report of EnLink Midstream Partners, LP (the "Registrant") on Form 10-Q for the quarter ended March 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of EnLink Midstream GP, LLC, and Michael J. Garberding, Chief Financial Officer of EnLink Midstream GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ BARRY E. DAVIS
Barry E. Davis
Chief Executive Officer

May 4, 2016

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
Chief Financial Officer

May 4, 2016

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.