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

FORM 10-Q

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

For the quarterly period ended September 30, 2016

OR

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

For the transition period from to

Commission file number 1-36175

MIDCOAST ENERGY PARTNERS, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1714064**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana Street,
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)
(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the 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 Exchange Act). Yes ☐ No ☒

The registrant had 22,610,056 Class A common units outstanding as of October 28, 2016.

MIDCOAST ENERGY PARTNERS, L.P.

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In this report, unless the context otherwise requires, references to "Midcoast Energy Partners," "the Partnership," "MEP," "we," "our," "us," or like terms refer to Midcoast Energy Partners, L.P. and its subsidiaries. We refer to our general partner, Midcoast Holdings, L.L.C., as our "General Partner" and to Enbridge Energy Partners, L.P. and its subsidiaries, other than us, as "Enbridge Energy Partners," or "EEP." References to "Enbridge" refer collectively to Enbridge Inc. and its subsidiaries other than us, our subsidiaries, our General Partner, EEP, its subsidiaries and its general partner. References to "Enbridge Management" refer to Enbridge Energy Management, L.L.C., the delegate of EEP's general partner that manages EEP's business and affairs. References to "Midcoast Operating" refer to Midcoast Operating, L.P. and its subsidiaries. As of September 30, 2016, we owned a 51.6% controlling interest in Midcoast Operating, and EEP owned a 48.4% noncontrolling interest, or NCI, in Midcoast Operating. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's 48.4% noncontrolling interest in Midcoast Operating as of September 30, 2016.

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "consider," "continue," "could," "estimate," "evaluate," "expect," "explore," "forecast," "intend," "may," "opportunity," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for, the supply of, forecast data for, and price trends related to natural gas, natural gas liquids, or NGLs, and crude oil, and the response by natural gas and crude oil producers to changes in any of these factors; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline and gathering systems, as well as *other processing and treating plants; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to which we sell products; (5) hazards and operating risks that may not be covered fully by insurance; (6) changes in or challenges to our rates; (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance; (8) cost overruns and delays on construction projects resulting from numerous factors; (9) our ability to comply with covenants in our debt agreements; and (10) the results of our and EEP's reviews of strategic alternatives as discussed herein.*

For additional factors that may affect results, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015, which is available to the public over the Internet at the U.S. Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.midcoastpartners.com).

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

MIDCOAST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Commodity sales (Note 13)	$440.7	$597.8	$1,197.9	$2,101.3
Commodity sales – affiliate (Notes 11 and 13)	1.3	12.0	7.9	62.3
Transportation and other services	44.0	51.2	139.7	151.0
	486.0	661.0	1,345.5	2,314.6
Operating expenses:				
Cost of natural gas and natural gas liquids (Notes 5 and 13)	396.1	503.3	1,082.0	1,912.0
Cost of natural gas and natural gas liquids – affiliate (Notes 11 and 13)	7.9	19.4	29.1	60.4
Operating and maintenance	34.8	48.8	105.7	131.7
Operating and maintenance – affiliate (Note 11)	20.1	25.2	68.3	75.2
General and administrative	1.8	1.6	5.7	4.6
General and administrative – affiliate (Note 11)	16.4	19.6	45.0	56.5
Goodwill impairment	—	—	—	226.5
Asset impairment	—	—	10.6	12.3
Depreciation and amortization	39.2	39.2	118.7	118.3
	516.3	657.1	1,465.1	2,597.5
Operating income (loss)	(30.3)	3.9	(119.6)	(282.9)
Interest expense, net (Note 9)	(8.5)	(7.6)	(25.0)	(21.5)
Equity in earnings of joint ventures (Note 8)	8.3	8.9	22.0	20.5
Other income (loss)	0.1	(0.4)	0.3	(0.2)
Income (loss) before income tax expense	(30.4)	4.8	(122.3)	(284.1)
Income tax expense (Note 14)	(0.7)	(3.7)	(2.1)	(1.4)
Net income (loss)	(31.1)	1.1	(124.4)	(285.5)
Less: Net income (loss) attributable to noncontrolling interest	(10.4)	4.7	(46.7)	(125.4)
Net loss attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ (20.7)	$ (3.6)	$ (77.7)	$ (160.1)
Net loss attributable to limited partner ownership interest	$ (20.3)	$ (3.5)	$ (76.1)	$ (156.8)
Net loss per limited partner unit (basic and diluted) (Note 2)	$ (0.45)	$ (0.08)	$ (1.68)	$ (3.47)
Weighted-average limited partner units outstanding	45.2	45.2	45.2	45.2

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(unaudited; in millions)			
Net income (loss)	$(31.1)	$ 1.1	$(124.4)	$(285.5)
Other comprehensive loss, net of tax (Note 13)	—	(5.2)	—	(16.1)
Comprehensive loss	(31.1)	(4.1)	(124.4)	(301.6)
Less:				
Net income (loss) attributable to noncontrolling interest	(10.4)	4.7	(46.7)	(125.4)
Other comprehensive loss attributed to noncontrolling interest	—	(2.5)	(0.1)	(7.8)
Comprehensive loss attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$(20.7)	$(6.3)	$ (77.6)	$(168.4)

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the nine months ended September 30,	
	2016	2015
	(unaudited; in millions)	
Cash provided by operating activities:		
Net loss	$(124.4)	$(285.5)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	118.7	118.3
Goodwill impairment	—	226.5
Derivative fair value net losses (Note 13)	87.5	53.5
Inventory market price adjustments (Note 5)	—	5.4
Asset impairment	10.6	12.3
Distributions from investment in joint ventures	22.0	20.5
Equity earnings from investment in joint ventures	(22.0)	(20.5)
Loss on sales of assets	1.6	3.2
Other	(1.4)	2.6
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	8.4	13.9
Due from General Partner and affiliates	51.5	38.7
Accrued receivables	25.1	200.6
Inventory	(31.5)	(9.8)
Current and long-term other assets	(10.8)	1.8
Due to General Partner and affiliates	33.8	13.3
Accounts payable and other	(25.0)	(20.6)
Accrued purchases	(7.5)	(177.2)
Interest payable	(3.7)	(3.8)
Property and other taxes payable	7.0	5.4
Net cash provided by operating activities	139.9	198.6
Cash used in investing activities:		
Additions to property, plant and equipment (Note 16)	(52.8)	(155.4)
Changes in restricted cash (Note 4)	10.9	32.1
Acquisitions	—	(43.9)
Proceeds from sales of assets	13.6	2.1
Investment in joint ventures	—	(3.0)
Distributions from investment in joint ventures in excess of cumulative earnings	12.3	9.5
Other	(1.2)	(1.6)
Net cash used in investing activities	(17.2)	(160.2)
Cash used in financing activities:		
Net borrowings (repayments) under credit facility (Note 9)	(40.0)	60.0
Distributions to partners (Note 10)	(49.5)	(48.1)
Contributions from General Partner (Note 11)	9.5	—
Contributions from noncontrolling interest	7.3	37.3
Distributions to noncontrolling interest (Note 10)	(68.0)	(72.0)
Net cash used in financing activities	(140.7)	(22.8)
Net increase (decrease) in cash and cash equivalents	(18.0)	15.6
Cash and cash equivalents at beginning of year	18.0	—
Cash and cash equivalents at end of period	$ —	$ 15.6

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2016	December 31, 2015
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	$ —	$ 18.0
Restricted cash (Note 4)	6.7	20.6
Receivables, trade and other, net of allowance for doubtful accounts of $2.3 million and $2.5 million at September 30, 2016 and December 31, 2015, respectively	4.7	13.3
Due from General Partner and affiliates (Note 11)	3.8	47.0
Accrued receivables	31.0	56.1
Inventory (Note 5)	63.2	31.9
Other current assets (Note 13)	64.9	118.5
	174.3	305.4
Property, plant and equipment, net (Note 6)	4,133.0	4,226.3
Intangible assets, net	256.9	272.9
Equity investment in joint ventures (Note 8)	359.6	372.3
Other assets, net (Note 13)	57.9	95.2
Total assets	$4,981.7	$5,272.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 11)	$ 60.7	$ 45.7
Accounts payable and other (Notes 4 and 13)	55.8	92.6
Accrued purchases	136.3	143.8
Property and other taxes payable (Note 14)	25.4	18.4
Interest payable	1.5	5.2
	279.7	305.7
Long-term debt (Note 9)	848.5	888.2
Other long-term liabilities (Notes 13 and 14)	27.6	45.9
Total liabilities	1,155.8	1,239.8
Commitments and contingencies (Note 12)		
Partners' capital (Note 10):		
Class A common units (22,610,056 authorized and issued at September 30, 2016 and December 31, 2015)	459.9	522.2
Subordinated units (22,610,056 authorized and issued at September 30, 2016 and December 31, 2015)	999.7	1,062.0
General Partner units (922,859 authorized and issued at September 30, 2016 and December 31, 2015)	50.2	43.3
Accumulated other comprehensive loss (Note 13)	(0.9)	(0.9)
Total Midcoast Energy Partners, L.P. partners' capital	1,508.9	1,626.6
Noncontrolling interest	2,317.0	2,405.7
Total partners' capital	3,825.9	4,032.3
	$4,981.7	$5,272.1

Variable Interest Entities (VIEs) — see Note 7.

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. ORGANIZATION AND NATURE OF OPERATIONS

Midcoast Energy Partners, L.P. is a publicly-traded Delaware limited partnership formed by Enbridge Energy Partners, L.P., or EEP, to serve as EEP's primary vehicle for owning and growing its natural gas and natural gas liquids midstream business in the United States. Midcoast Energy Partners, L.P., together with its consolidated subsidiaries, are referred to in this report as ''we,'' ''us,'' ''our,'' ''MEP'' and the ''Partnership.'' We own and operate, through our 51.6% controlling interest in Midcoast Operating, L.P., or Midcoast Operating, a portfolio of assets engaged in the business of gathering, processing and treating natural gas, as well as the transportation of natural gas, natural gas liquids, or NGLs, crude oil and condensate. In addition, we also provide marketing services of natural gas and NGLs to wholesale customers. Our portfolio of natural gas and NGL pipelines, plants and related facilities are geographically concentrated in the Gulf Coast and Mid-Continent regions of the United States, primarily in Texas and Oklahoma. EEP owns a 48.4% noncontrolling interest in Midcoast Operating. EEP also has a significant interest in us through its ownership of our General Partner, which owns all of our General Partner units and all of our incentive distribution rights, or IDRs, as well as an approximate 52% limited partner interest in us. Our Class A common units trade on the New York Stock Exchange, or NYSE, under the ticker symbol ''MEP.''

Basis of Presentation

We have prepared the accompanying unaudited interim consolidated financial statements in accordance with generally accepted accounting principles in the United States of America, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, the unaudited interim consolidated financial statements do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of September 30, 2016, our results of operations for the three and nine months ended September 30, 2016 and 2015, and our cash flows for the nine months ended September 30, 2016 and 2015. We derived our consolidated statement of financial position as of December 31, 2015 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015. Our results of operations for the three and nine months ended September 30, 2016 and 2015, should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for natural gas, NGLs and crude oil, timing and completion of our construction projects, maintenance activities, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value. Our unaudited interim consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner and limited partners using the two-class method. Under the two-class method, we allocate our net income, including any earnings in excess of distributions, to our limited partners, our General Partner and the holders of our IDRs in accordance with the terms of our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and our limited partners based on their respective proportionate ownership interests in us, after taking into account distributions to be paid with respect to the IDRs, as set forth in our partnership agreement.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to Limited Partners	Percentage Distributed to General Partner
Minimum Quarterly Distribution	Up to $0.3125	98%	2%
First Target Distribution	> $0.3125 to $0.359375	98%	2%
Second Target Distribution	> $0.359375 to $0.390625	85%	15%
Third Target Distribution	> $0.390625 to $0.468750	75%	25%
Over Third Target Distribution	In excess of $0.468750	50%	50%

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST – (continued)

We determined basic and diluted net loss per limited partner unit as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions, except per unit amounts)			
Net income (loss)	$(31.1)	$ 1.1	$(124.4)	$(285.5)
Less: Net income (loss) attributable to noncontrolling interest	(10.4)	4.7	(46.7)	(125.4)
Net loss attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	(20.7)	(3.6)	(77.7)	(160.1)
Distributions:				
Total distributed earnings to our General Partner	(0.3)	(0.3)	(0.9)	(0.9)
Total distributed earnings to our limited partners	(16.2)	(16.2)	(48.6)	(47.9)
Total distributed earnings	(16.5)	(16.5)	(49.5)	(48.8)
Overdistributed earnings	$(37.2)	$(20.1)	$(127.2)	$(208.9)
Weighted-average limited partner units outstanding	45.2	45.2	45.2	45.2
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit(1)	$ 0.36	$ 0.36	$ 1.08	$ 1.06
Overdistributed earnings per limited partner unit(2)	(0.81)	(0.44)	(2.76)	(4.53)
Net loss per limited partner unit (basic and diluted)	$(0.45)	$(0.08)	$ (1.68)	$ (3.47)

(1) Represents the total distributed earnings to limited partners divided by the weighted-average number of limited partner interests outstanding for the period.

(2) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted-average number of limited partner interests outstanding for the period and underdistributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

3. ACQUISITIONS

On February 27, 2015, we acquired a midstream business, which consisted of a natural gas gathering system in Leon, Madison and Grimes Counties, Texas. We acquired the midstream business for $85.0 million in cash and a contingent future payment of up to $17.0 million.

Of the $85.0 million purchase price, $20.0 million was placed into escrow, pending the resolution of a legal matter and completion and connection of additional wells to our system by February 2016. Since the acquisition date, we released $17.0 million from escrow for additional wells connected to our system and for the resolution of the legal matter. During the first quarter of 2016, $3.0 million in escrow was returned to us, as some of the additional wells were not connected to our system by February 2016. As a result, we recognized a $3.0 million gain as a reduction to ''Operating and maintenance'' expense, which is reflected in our consolidated statements of income for the nine months ended September 30, 2016. At September 30, 2016, no amounts remained in escrow.

The purchase and sale agreement contained a provision whereby we would have been obligated to make future tiered payments of up to $17.0 million if volumes were delivered into the system at certain tiered volume levels over a five-year period. We determined at the time of the acquisition that the potential payment was contingent consideration. At the acquisition date, the fair value of this contingent consideration, using a probability-weighted discounted cash flow model was $2.3 million. The contingent consideration was re-measured on a fair value basis each quarter until December 31, 2015, which resulted in an addition to the liability of $0.3 million for accretion. During the first quarter of 2016, and in subsequent reassessments, we determined, based on current and forecasted volumes, that it is remote that we will be obligated to make any payments at the expiration of the five-year period. Consequently, we reversed the liability and recognized a $2.6 million gain as a reduction to ''Operating and maintenance'' expense, which is reflected in our consolidated statements of income for the nine months ended September 30, 2016.

4. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution, totaling approximately $3.3 million and $4.2 million at September 30, 2016 and December 31, 2015, respectively, are included in ''Accounts payable and other'' on our consolidated statements of financial position.

Restricted Cash

Restricted cash is comprised of the following:

	September 30, 2016	December 31, 2015
	(in millions)	
Cash collateral on behalf of Enbridge subsidiary for accounts receivable sales and not remitted (see Note 11)	$6.7	$14.6
Cash held in escrow for acquisitions (see Note 3)	—	6.0
	$6.7	$20.6

5. INVENTORY

Our inventory is comprised of the following:

	September 30, 2016	December 31, 2015
	(in millions)	
Materials and supplies	$ 0.2	$ 0.6
Natural gas and NGL inventory	63.0	31.3
	$63.2	$31.9

The ''Cost of natural gas and natural gas liquids'' on our consolidated statements of income includes charges totaling $0.1 million and $5.4 million for the three and nine months ended September 30, 2015, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs, to reflect the current market value. For the three and nine months ended September 30, 2016, we did not have any similar material charges related to our inventory of natural gas and NGLs.

6. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	September 30, 2016	December 31, 2015
	(in millions)	
Land	$ 24.4	$ 14.2
Rights-of-way	457.5	460.3
Pipelines	1,875.0	1,864.4
Pumping equipment, buildings and tanks	87.5	88.4
Compressors, meters and other operating equipment	2,180.1	2,147.6
Vehicles, office furniture and equipment	87.1	137.1
Processing and treating plants	630.0	627.8
Construction in progress	25.2	57.1
Total property, plant and equipment	5,366.8	5,396.9
Accumulated depreciation	(1,233.8)	(1,170.6)
Property, plant and equipment, net	$ 4,133.0	$ 4,226.3

6. PROPERTY, PLANT AND EQUIPMENT – (continued)

On August 15, 2016, we sold certain trucks, trailers and related facilities in our Logistics and Marketing segment for $12.1 million. At the date of sale, the assets had a total carrying amount of $14.0 million. The loss on disposal of $1.9 million for the three and nine months ended September 30, 2016 is included in ‘‘Operating and maintenance’’ expense on our consolidated statement of income. The carrying amount of these assets was classified as assets held for sale in ‘‘Other current assets’’ on our consolidated statements of financial position before the sale. During the second quarter of 2016, we recorded $10.6 million in non-cash impairment charges on these assets, which are included in ‘‘Asset impairment’’ on our consolidated statements of income.

7. VARIABLE INTEREST ENTITIES

Principles of Consolidation

On January 1, 2016, we adopted Accounting Standards Update, or ASU, No. 2015-02, which amended consolidation guidance to, among other things, eliminate the specialized consolidation model and guidance for limited partnerships, including the presumption that the general partner should consolidate a limited partnership. As a result, we have determined that certain entities that we historically consolidated under this presumption are variable interest entities, or VIEs. Further, we determined that we are the primary beneficiary for these VIEs and will continue to consolidate these entities under the amended guidance. While the amended guidance did not impact our conclusion that such entities should be consolidated, because such entities are now considered VIEs, additional disclosures are necessary. We have applied this amended guidance retrospectively to our disclosures.

The consolidated financial statements include our accounts, and accounts of our subsidiaries and VIEs for which we are the primary beneficiary. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. Where we conclude we are the primary beneficiary of a VIE, we consolidate the accounts of that entity.

We assess all aspects of our interests in an entity and use judgment when determining if we are the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. Reassessment of the primary beneficiary conclusion is conducted on an ongoing basis as there are changes in the facts and circumstances related to each VIE.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to NCI. Investments and entities over which we exercise significant influence are accounted for using the equity method.

Midcoast Operating

Midcoast Operating is a Texas limited partnership. As of September 30, 2016, we owned a 51.6% direct limited partner interest in Midcoast Operating. In addition, we own Midcoast Operating’s general partner, Midcoast OLP GP, L.L.C. EEP owns the remaining limited partner interests in Midcoast Operating. We are the primary beneficiary of Midcoast Operating because (1) through our ownership in Midcoast Operating’s general partner and our majority limited partner interest, we have the power to direct the activities that most significantly impact Midcoast Operating’s economic performance; and (2) we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to Midcoast Operating. In addition, we are the entity within the related party group that is most closely associated with Midcoast Operating.

As of September 30, 2016 and December 31, 2015, our consolidated statements of financial position include total assets of $4,974.4 million and $5,241.5 million, respectively, and total liabilities of $257.7 million and $323.7 million, respectively, related to Midcoast Operating. The assets of Midcoast Operating can only be used to settle their obligations, which include a cross-guarantee under MEP’s senior revolving credit facility, or the Credit Agreement, and a guarantee of MEP’s senior notes. We do not have an obligation to provide financial support to

7. VARIABLE INTEREST ENTITIES – (continued)

Midcoast Operating other than by virtue of certain contractual obligations prescribed by the terms of certain indemnities and guarantees to pay certain liabilities of Midcoast Operating in the event of a default.

The following table includes assets to be used to settle liabilities of Midcoast Operating and liabilities of Midcoast Operating for which creditors do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in our consolidated balance sheet.

	September 30, 2016	December 31, 2015
	(in millions)	
ASSETS		
Cash and cash equivalents	$ —	$ 3.4
Restricted cash	$ —	$ 6.0
Receivables, trade and other, net	$ 4.7	$ 13.3
Due from General Partner and affiliates	$ 3.7	$ 46.9
Accrued receivables	$ 31.0	$ 56.1
Inventory	$ 63.2	$ 31.9
Other current assets	$ 64.9	$ 118.5
Property, plant and equipment, net	$4,133.0	$4,226.3
Intangible assets, net	$ 256.9	$ 272.9
Equity investment in joint ventures	$ 359.6	$ 372.3
Other assets, net	$ 57.4	$ 93.9
LIABILITIES		
Due to General Partner and affiliates	$ 16.1	$ 28.5
Accounts payable and other	$ 52.3	$ 87.1
Accrued purchases	$ 136.3	$ 143.8
Property and other taxes payable	$ 25.4	$ 18.4
Other long-term liabilities	$ 27.6	$ 45.9

8. EQUITY INVESTMENTS IN JOINT VENTURES

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties. The Texas Express NGL system consists of a 593-mile NGL intrastate transportation pipeline and a related NGL gathering system. Our investment in and earnings from the Texas Express NGL system are presented in ‘‘Equity investment in joint ventures’’ on our consolidated statements of financial position and ‘‘Equity in earnings of joint ventures’’ on our consolidated statements of income, respectively. The following table presents unaudited income statement information for the Texas Express NGL system on a combined, 100% basis for the periods presented:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating revenues	$36.1	$36.5	$100.3	$93.9
Operating expenses	$12.7	$11.1	$ 37.4	$33.8
Net income	$23.5	$25.4	$ 62.8	$59.9

9. DEBT

The following table presents the carrying amounts of our consolidated debt obligations:

	Interest Rate	September 30, 2016	December 31, 2015
		(in millions)	
Credit Agreement due 2018	3.431%	$450.0	$490.0
Series A Senior Notes due September 2019	3.560%	75.0	75.0
Series B Senior Notes due September 2021	4.040%	175.0	175.0
Series C Senior Notes due September 2024	4.420%	150.0	150.0
Total principal amount of debt obligations		850.0	890.0
Unamortized debt issuance costs		(1.5)	(1.8)
Total		$848.5	$888.2

On January 1, 2016, we adopted ASU No. 2015-03, which requires us to present debt issuance costs in the balance sheet as a reduction to the carrying amount of the debt liability, rather than as an asset. We have retrospectively adopted this guidance for all periods presented. The adoption of this guidance did not have a material impact on our consolidated financial statements.

Our interest cost for the three and nine months ended September 30, 2016, and 2015, is comprised of the following:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Interest cost incurred	$8.5	$7.8	$25.0	$23.0
Less: Interest capitalized	—	0.2	—	1.5
Interest expense, net	$8.5	$7.6	$25.0	$21.5

Debt Arrangements

Credit Agreement

We, Midcoast Operating, and our material domestic subsidiaries are parties to the Credit Agreement, which permits aggregate borrowings of up to $810.0 million at any one time outstanding. The original term of the Credit Agreement was three years, with an initial maturity date of November 13, 2016, subject to four one-year requests for extension at the lenders' discretion, two of which we have utilized. Our Credit Agreement's current maturity date is September 30, 2018; however, $140.0 million of commitments expire on the initial maturity date of November 13, 2016 and an additional $25.0 million of commitments expire on September 30, 2017. During the nine months ended September 30, 2016, we had net repayments of approximately $40.0 million, which includes gross borrowings of $5,715.0 million and gross repayments of $5,755.0 million.

Debt Covenants

At September 30, 2016, we were in compliance with the terms of our financial covenants under our debt agreements.

9. DEBT – (continued)

Available Credit

At September 30, 2016, we had approximately $360.0 million of unutilized commitments under the terms of our Credit Agreement, determined as follows:

	(in millions)
Total commitments under Credit Agreement	$ 810.0
Amounts outstanding under Credit Agreement	(450.0)
Total unutilized commitments at September 30, 2016	$ 360.0

Fair Value of Debt Obligations

The carrying amount of our outstanding borrowings under the Credit Agreement approximates the fair value at September 30, 2016 and December 31, 2015, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The outstanding borrowings under the Credit Agreement are included with our long-term debt obligations since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair values of our fixed-rate debt obligations were $411.9 million at September 30, 2016. We determined the approximate fair values using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligations is categorized as Level 2 within the fair value hierarchy.

10. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of our General Partner, during the nine months ended September 30, 2016:

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
			(in millions, except per unit amounts)	
July 27, 2016	August 5, 2016	August 12, 2016	$0.35750	$16.5
April 28, 2016	May 6, 2016	May 13, 2016	$0.35750	$16.5
January 28, 2016	February 5, 2016	February 12, 2016	$0.35750	$16.5

Cash distributed to partners is reflected in "Distributions to partners," on our consolidated statements of cash flows. We paid cash distributions to EEP for its ownership interest in us totaling $8.9 million and $8.8 million for the three months ended September 30, 2016 and 2015, respectively, and $26.7 million and $25.9 million for the nine months ended September 30, 2016 and 2015, respectively.

Distributions to Noncontrolling Interests

Midcoast Operating paid cash distributions to EEP for its ownership interest in Midcoast Operating totaling $19.2 million and $26.2 million for the three months ended September 30, 2016 and 2015, respectively, and $68.0 million and $72.0 million for the nine months ended September 30, 2016 and 2015, respectively. These amounts are reflected in "Distributions to noncontrolling interest" in our consolidated statements of cash flows.

During any quarter until the quarter ending December 31, 2017, if our quarterly declared distribution exceeds our distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement, we receive an increased quarterly distribution from Midcoast Operating, and EEP receives a corresponding reduction to its quarterly distribution in the amount that our declared distribution exceeds our distributable cash. Midcoast Operating's adjustment of EEP's distribution will be limited by EEP's pro rata share of the Midcoast Operating quarterly cash distribution and a maximum of $0.005 per unit quarterly distribution increase by us. There is no

10. PARTNERS' CAPITAL – (continued)

requirement for us to compensate EEP for these adjusted distributions, except for settling our capital accounts with Midcoast Operating in a liquidation scenario. For the three and nine months ended September 30, 2016, EEP's quarterly distribution from Midcoast Operating was reduced by $5.1 million and $8.2 million, respectively.

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary during the nine months ended September 30, 2016 and 2015:

	For the nine months ended September 30,	
	2016	2015
	(in millions)	
Class A Common units:		
Beginning balance	$ 522.2	$ 634.2
Net loss	(38.0)	(78.4)
Distributions	(24.3)	(23.6)
Ending balance	$ 459.9	$ 532.2
Subordinated units:		
Beginning balance	$1,062.0	$1,174.0
Net loss	(38.0)	(78.4)
Distributions	(24.3)	(23.6)
Ending balance	$ 999.7	$1,072.0
General Partner units:		
Beginning balance	$ 43.3	$ 47.8
Net loss	(1.7)	(3.3)
Contributions	9.5	—
Distributions	(0.9)	(0.9)
Ending balance	$ 50.2	$ 43.6
Accumulated other comprehensive income (loss):		
Beginning balance	$ (0.9)	$ 11.6
Changes in fair value of derivative financial instruments reclassified to earnings	—	(12.5)
Changes in fair value of derivative financial instruments recognized in other comprehensive income	—	4.2
Ending balance	$ (0.9)	$ 3.3
Noncontrolling interest:		
Beginning balance	$2,405.7	$2,529.0
Capital contributions	26.1	97.2
Comprehensive income:		
Net loss	(46.7)	(125.4)
Other comprehensive loss, net of tax	(0.1)	(7.8)
Distributions to noncontrolling interest	(68.0)	(72.0)
Ending balance	$2,317.0	$2,421.0
Total partners' capital at end of period	$3,825.9	$4,072.1

10. PARTNERS' CAPITAL – (continued)

Securities Authorized for Issuance under LTIP

In August 2014, we filed a registration statement on Form S-8 with the SEC registering the issuance of 3,750,000 Class A common units that are issuable pursuant to awards that may be granted under the Long-Term Incentive Plan, or the LTIP. As of September 30, 2016, we had not granted any awards for, or that are convertible into, Class A common units under our LTIP.

11. RELATED PARTY TRANSACTIONS

We do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. Enbridge and its affiliates provide management, administrative, operational and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

The affiliate amounts incurred by us through EEP for services received pursuant to the Intercorporate Services Agreement are reflected in ''Operating and maintenance — affiliate'' and ''General and administrative — affiliate'' on our consolidated statements of income. Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. However, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. As a result, we recognized $6.3 million for each of the three months ended September 30, 2016 and 2015, and $18.8 million for each of the nine months ended September 30, 2016 and 2015, as a reduction to ''Due to general partner and affiliates'' with an offset recorded as contribution to ''Noncontrolling interest'' in our consolidated statements of financial position.

Omnibus Agreement

We, Midcoast Holdings, EEP, and Enbridge are parties to the Omnibus Agreement under which EEP agreed to, among other things, indemnify us for certain matters, including environmental, right-of-way and permit matters. EEP's obligation to indemnify us for these matters is subject to a $500,000 aggregate deductible before we are entitled to indemnification. Additionally, there is a $15.0 million aggregate cap on the amounts for which EEP will indemnify us for under the Omnibus Agreement. During the first quarter of 2016, we received indemnification proceeds from EEP under the Omnibus Agreement of $12.2 million for the acquisition of title to right-of-way assets that were pending at the time of our initial public offering and associated legal fees. There have been no other payments from EEP under the Omnibus Agreement. Indemnification amounts of $9.5 million are classified as a contribution from our General Partner in our consolidated statements of cash flows for the nine months ended September 30, 2016 and reflected in the General Partner capital account in our consolidated statement of financial position as of September 30, 2016. The remaining $2.7 million is classified as a reduction of legal expenses reflected in ''General and administrative — affiliate'' expense in our consolidated statements of income for the nine months ended September 30, 2016.

Affiliate Revenues and Purchases

We sell NGLs and crude oil at market prices on the date of sale to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in ''Commodity sales — affiliate'' on our consolidated statements of income. We also purchase NGLs and crude oil at market prices on the date of purchase from Enbridge and its affiliates for sale to third parties. The purchases from Enbridge and its affiliates are presented in ''Cost of natural gas and natural gas liquids — affiliate'' on our consolidated statements of income.

Also included in ''Cost of natural gas and natural gas liquids — affiliate,'' are pipeline transportation and demand fees from the Texas Express NGL system of $4.6 million and $5.1 million for the three months ended September 30, 2016 and 2015, respectively, and $14.9 million and $13.4 million for the nine months ended September 30, 2016 and 2015, respectively. Our logistics and marketing business has made commitments to transport up to 120,000 barrels per day, or Bpd, of NGLs on the Texas Express NGL system by 2022. Our current commitment level is 29,000 Bpd and our average commitment level will increase to 75,000 Bpd in 2017.

11. RELATED PARTY TRANSACTIONS – (continued)

Routine purchases and sales with affiliates are settled monthly through our centralized treasury function. Routine purchases and sales with affiliates that have not yet been settled are included in "Due from general partner and affiliates" and "Due to general partner and affiliates" on our consolidated statements of financial position.

Sale of Accounts Receivable

We sold and derecognized receivables to an indirect wholly-owned subsidiary of Enbridge of $421.9 million and $509.8 million for the three months ended September 30, 2016 and 2015, respectively, and $1,161.0 million and $1,752.4 million for the nine months ended September 30, 2016 and 2015, respectively. As a result, we received cash proceeds of $421.7 million and $509.7 million for the three months ended September 30, 2016 and 2015, respectively, and $1,160.5 million and $1,751.9 million for the nine months ended September 30, 2016 and 2015, respectively.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative — affiliate" expense in our consolidated statements of income. The expense stemming from the discount on the receivables sold was $0.2 million and $0.1 million for the three months ended September 30, 2016 and 2015, respectively, and $0.5 million for each of the nine months ended September 30, 2016 and 2015.

As of September 30, 2016 and December 31, 2015, we had $6.7 million and $14.6 million, respectively, in "Restricted cash" on our consolidated statements of financial position for cash collections related to sold and derecognized receivables that have yet to be remitted to the Enbridge subsidiary. As of September 30, 2016 and December 31, 2015, outstanding receivables of $143.8 million and $147.1 million, respectively, which had been sold and derecognized, had not been collected on behalf of the Enbridge subsidiary.

Financial Support Agreement

At September 30, 2016, EEP provided no letters of credit and $24.8 million of guarantees to Midcoast Operating under a Financial Support Agreement with Midcoast Operating. At December 31, 2015, EEP provided $7.5 million of letters of credit outstanding and $21.7 million in guarantees to Midcoast Operating under this agreement. The annual costs that Midcoast Operating incurs under the Financial Support Agreement are based on the cumulative average amount of letters of credit and guarantees that EEP provides on behalf of Midcoast Operating and its wholly-owned subsidiaries, multiplied by a 2.5% annual fee. Midcoast Operating incurred $0.1 million of these costs for each of the three months ended September 30, 2016 and 2015, and $0.4 million for each of the nine months ended September 30, 2016 and 2015, which are included in "Operating and maintenance — affiliate" on our consolidated statements of income.

12. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to our operating activities, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or otherwise, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities. We continue to voluntarily monitor past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations. As of September 30, 2016 and December 31, 2015, we did not have any material accrued environmental liabilities.

12. COMMITMENTS AND CONTINGENCIES – (continued)

Legal and Regulatory Proceedings

We are a participant in a number of legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial position, results of operations or cash flows. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with commodity price risks in future periods in accordance with our risk management policies. Our derivative instruments that are designated for hedge accounting under authoritative guidance are classified as cash flow hedges.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	September 30, 2016	December 31, 2015
	(in millions)	
Other current assets	$ 52.5	$117.3
Other assets, net	9.0	39.2
Accounts payable and other[(1)]	(35.9)	(45.7)
Other long-term liabilities	(8.0)	(18.3)
	$ 17.6	$ 92.5

(1) Includes $12.6 million of cash collateral at December 31, 2015.

The changes in the assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

The table below summarizes our derivative balances by counterparty credit quality (any negative amounts represent our net obligations to pay the counterparty):

	September 30, 2016	December 31, 2015
	(in millions)	
Counterparty Credit Quality[1]		
AA[2]	$18.7	$67.6
A	(0.9)	24.1
Lower than A	(0.2)	0.8
	$17.6	$92.5

(1) As determined by nationally-recognized statistical ratings organizations.

(2) Includes $12.6 million of cash collateral at December 31, 2015.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. At September 30, 2016, we did not have any cash collateral on our asset exposures. At December 31, 2015, our short-term liabilities included $12.6 million relating to cash collateral on our asset exposures. Cash collateral is classified as "Restricted cash" in our consolidated statements of financial position. As of December 31, 2015, all of our cash collateral was held directly by EEP.

At September 30, 2016, we provided no letters of credit relating to our liability exposures pursuant to the margin thresholds in effect under our ISDA® agreements. At December 31, 2015, we provided letters of credit totaling $7.5 million. The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

We do not currently have a credit rating. For purposes of our ISDA® agreements, we calculate an implied credit rating based on EEP's credit ratings. In the event that our implied credit ratings were to decline below the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our implied credit ratings had been below the lowest level of investment grade at September 30, 2016, we would have been required to provide additional letters of credit in the amount of $10.6 million related to our open positions.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

At September 30, 2016, and December 31, 2015, we had credit concentrations in the following industry sectors, as presented below:

	September 30, 2016	December 31, 2015
	(in millions)	
United States financial institutions and investment banking entities[1]	$16.4	$ 80.8
Non-United States financial institutions	(8.9)	(12.3)
Integrated oil companies	(1.1)	0.6
Other	11.2	23.4
	$17.6	$ 92.5

(1) Includes $12.6 million of cash collateral at December 31, 2015.

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter, or OTC, derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
	Financial Position Location	September 30, 2016	December 31, 2015	September 30, 2016	December 31, 2015
		(in millions)			
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	$52.5	$117.3	$ —	$ —
Commodity contracts	Other assets, net	9.0	39.2	—	—
Commodity contracts	Accounts payable and other[1]	—	—	(35.9)	(33.1)
Commodity contracts	Other long-term liabilities	—	—	(8.0)	(18.3)
Total derivative instruments		$61.5	$156.5	$(43.9)	$(51.4)

(1) Liability derivatives exclude $12.6 million of cash collateral at December 31, 2015.

Accumulated Other Comprehensive Income

We record the change in fair value of our highly effective cash flow hedges in accumulated other comprehensive income, or AOCI, until the derivative financial instruments are settled, at which time they are reclassified to earnings. As of September 30, 2016 and December 31, 2015, we included in AOCI unrecognized losses of approximately $0.5 million and $0.4 million, respectively, associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated, settled, or terminated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the nine months ended September 30, 2015, unrealized commodity hedge gains of $1.5 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We had no commodity hedges de-designated during the nine months ended September 30, 2016. We estimate that approximately $0.1 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at September 30, 2016, will be reclassified from AOCI to earnings during the next 12 months.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]
		(in millions)			
For the three months ended September 30, 2016					
Interest Rate contracts	$ —	Interest expense	$ —	Interest expense	$ —
Commodity contracts	—	Cost of natural gas and natural gas liquids	—	Cost of natural gas and natural gas liquids	—
Total	$ —		$ —		$ —
For the three months ended September 30, 2015					
Commodity contracts	$ (5.5)	Cost of natural gas and natural gas liquids	$ 8.5	Cost of natural gas and natural gas liquids	$(0.1)
For the nine months ended September 30, 2016					
Interest Rate contracts	$ —	Interest expense	$ (0.1)	Interest expense	$ —
Commodity contracts	—	Cost of natural gas and natural gas liquids	0.1	Cost of natural gas and natural gas liquids	—
	$ —		$ —		$ —
For the nine months ended September 30, 2015					
Commodity contracts	$(16.8)	Cost of natural gas and natural gas liquids	$24.0	Cost of natural gas and natural gas liquids	$(4.1)

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges	
	2016	2015
	(in millions)	
Balance at January 1	$(0.9)	$ 11.6
Other comprehensive income (loss) before reclassifications[1]	—	4.1
Amounts reclassified from AOCI[2][3]	—	(12.5)
Tax benefit	—	0.1
Net other comprehensive loss	$ —	$ (8.3)
Balance at September 30	$(0.9)	$ 3.3

(1) Excludes NCI gain of $3.7 million reclassified from AOCI at September 30, 2015.

(2) Excludes NCI loss of $11.5 million reclassified from AOCI at September 30, 2015.

(3) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Reclassifications from Accumulated Other Comprehensive Income

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Gains on cash flow hedges:				
Commodity Contracts[1][2][3]	$—	$(4.5)	$—	$(12.5)
Total Reclassifications from AOCI	$—	$(4.5)	$—	$(12.5)

(1) Gain reported within "Cost of natural gas and natural gas liquids" in the consolidated statements of income.

(2) Excludes NCI loss of $4.0 million reclassified from AOCI for the three months ended September 30, 2015.

(3) Excludes NCI loss of $11.5 million reclassified from AOCI for the nine months ended September 30, 2015.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	For the three months ended September 30, 2016	For the three months ended September 30, 2015	For the nine months ended September 30, 2016	For the nine months ended September 30, 2015
		Amount of Gain or (Loss) Recognized in Earnings[1][2]		Amount of Gain or (Loss) Recognized in Earnings[1][2]	
		(in millions)			
Commodity contracts	Commodity sales	$1.7	$ (7.2)	$ (1.8)	$(22.4)
Commodity contracts	Commodity sales – affiliate	—	—	—	(0.3)
Commodity contracts	Cost of natural gas and natural gas liquids[3]	2.4	40.7	(22.4)	44.3
Total		$4.1	$33.5	$(24.2)	$ 21.6

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.

(2) Includes only net gains or losses associated with those derivatives that do not receive hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

(3) Includes settlement gains of $18.7 million and $27.3 million for the three months ended September 30, 2016 and 2015, respectively, and settlement gains of $63.3 million and $71.0 million for the nine months ended September 30, 2016 and 2015, respectively.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a gross basis. However, the terms of the ISDA®, which govern our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party. The effect of the rights of set-off are outlined below:

Offsetting of Financial Assets and Derivative Assets

	As of September 30, 2016				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$61.5	$—	$61.5	$(29.5)	$32.0

	As of December 31, 2015				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position[(1)]	Net Amount
			(in millions)		
Description:					
Derivatives	$156.5	$—	$156.5	$(41.5)	$115.0

(1) Includes $12.6 million of cash collateral at December 31, 2015.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of September 30, 2016				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$(43.9)	$—	$(43.9)	$29.5	$(14.4)

	As of December 31, 2015				
	Gross Amount of Recognized Liabilities[(1)]	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position[(1)]	Net Amount
			(in millions)		
Description:					
Derivatives	$(64.0)	$—	$(64.0)	$41.5	$(22.5)

(1) Includes $12.6 million of cash collateral at December 31, 2015.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy of our net financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2016 and December 31, 2015. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	September 30, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Commodity contracts:								
Financial	$—	$(0.9)	$ 0.1	$ (0.8)	$—	$1.3	$ 8.9	$ 10.2
Physical	—	—	1.3	1.3	—	—	0.6	0.6
Commodity options	—	—	17.1	17.1	—	—	94.3	94.3
	$—	$(0.9)	$18.5	$17.6	$—	$1.3	$103.8	$105.1
Cash collateral				—				(12.6)
Total				$17.6				$ 92.5

Qualitative Information about Level 2 Fair Value Measurements

We categorize, as Level 2, the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument. This category includes both OTC transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (1) quoted prices for assets and liabilities; (2) time value; and (3) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to measure the fair value of our Level 3 derivative instruments on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (natural gas, NGLs and crude) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Forward commodity price in isolation has a direct relationship to the fair value of a commodity contract in a long position and an inverse relationship to a commodity contract in a short position. Volatility has a direct relationship to the fair value of an option contract. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. A change to the credit valuation has an inverse relationship to the fair value of our derivative contracts.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Quantitative Information about Level 3 Fair Value Measurements

Contract Type	Fair Value at September 30, 2016[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 1.3	Market Approach	Forward Natural Gas Price	2.65	3.59	3.08	MMBtu
NGLs	(1.2)	Market Approach	Forward NGL Price	0.22	1.12	0.51	Gal
Commodity Contracts – Physical							
Natural Gas	0.1	Market Approach	Forward Natural Gas Price	2.66	3.58	2.92	MMBtu
Crude Oil	(1.4)	Market Approach	Forward Crude Oil Price	38.45	49.58	46.32	Bbl
NGLs	2.6	Market Approach	Forward NGL Price	0.22	1.48	0.57	Gal
Commodity Options							
Natural Gas, Crude and NGLs	17.1	Option Model	Option Volatility	27%	97%	45%	
Total Fair Value	$18.5						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for natural gas, dollars per gallon, or Gal, for NGLs and dollars per barrel, or Bbl, for crude oil.

(2) Fair values include credit valuation adjustment losses of approximately $0.1 million.

Quantitative Information about Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2015[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 0.3	Market Approach	Forward Natural Gas Price	2.27	3.07	2.64	MMBtu
NGLs	8.6	Market Approach	Forward NGL Price	0.16	0.93	0.41	Gal
Commodity Contracts – Physical							
Natural Gas	(2.5)	Market Approach	Forward Natural Gas Price	2.08	3.44	2.33	MMBtu
Crude Oil	—	Market Approach	Forward Crude Oil Price	26.50	38.41	37.29	Bbl
NGLs	3.1	Market Approach	Forward NGL Price	0.16	1.20	0.40	Gal
Commodity Options							
Natural Gas, Crude and NGLs	94.3	Option Model	Option Volatility	13%	74%	36%	
Total Fair Value	$103.8						

(1) Prices are in dollars per MMBtu for natural gas, Gal for NGLs, and Bbl for crude oil.

(2) Fair values include credit valuation adjustment losses of approximately $0.3 million.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2016 to September 30, 2016. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
	(in millions)			
Beginning balance as of January 1, 2016	$ 8.9	$ 0.6	$ 94.3	$103.8
Transfer in (out) of Level 3[1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Commodity sales	—	(15.5)	—	(15.5)
Reported in Cost of natural gas and natural gas liquids	(0.5)	21.1	(21.9)	(1.3)
Gains or losses included in other comprehensive income:				
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	0.7	0.7
Settlements[2]	(8.3)	(4.9)	(56.0)	(69.2)
Ending balance as of September 30, 2016	$ 0.1	$ 1.3	$ 17.1	$ 18.5
Amounts reported in Commodity sales	$ —	$ (1.8)	$ —	$ (1.8)
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets and liabilities still held at the reporting date:				
Reported in Commodity sales	$ —	$ (3.5)	$ —	$ (3.5)
Reported in Cost of natural gas and natural gas liquids	$(0.9)	$ 4.6	$(15.9)	$ (12.2)

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2016 and December 31, 2015:

	At September 30, 2016						At December 31, 2015	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 2.86	$ 3.48	$—	$ —	$ —	$ —
	NGL	2,694,200	$26.38	$24.49	$5.7	$(0.6)	$ 0.2	$ (8.4)
	Crude Oil	169,400	$48.75	$62.50	$0.5	$(2.8)	$ —	$(17.5)
Receive fixed/pay variable	NGL	5,040,200	$23.97	$24.96	$3.2	$(8.2)	$18.3	$ (0.2)
	Crude Oil	232,400	$60.00	$48.64	$3.0	$(0.4)	$18.2	$ —
Receive variable/pay variable	Natural Gas	5,708,000	$ 3.05	$ 3.01	$0.3	$(0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,127,893	$25.14	$23.43	$2.0	$(0.1)	$ —	$ (0.2)
	Crude Oil	—	$ —	$ —	$—	$ —	$ —	$ (0.2)
Receive fixed/pay variable	NGL	1,359,447	$21.30	$23.31	$0.8	$(3.6)	$ 1.9	$ (0.2)
Receive variable/pay variable	Natural Gas	19,810,834	$ 2.83	$ 2.84	$0.1	$(0.3)	$ —	$ (2.8)
	NGL	3,794,987	$23.37	$23.07	$1.7	$(0.5)	$ 4.0	$ (2.4)
	Crude Oil	383,298	$44.16	$47.84	$0.3	$(1.8)	$ 0.7	$ (0.5)
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	989,030	$ 2.89	$ 2.91	$—	$ —	$ —	$ —
	NGL	2,417,500	$22.03	$21.62	$2.7	$(1.7)	$ —	$ (4.5)
	Crude Oil	638,750	$51.66	$64.29	$0.2	$(8.2)	$ —	$(10.9)
Receive fixed/pay variable	NGL	3,090,000	$22.70	$23.70	$1.2	$(4.3)	$ 3.3	$ (0.1)
	Crude Oil	638,750	$63.63	$51.66	$8.2	$(0.6)	$10.9	$ —
Receive variable/pay variable	Natural Gas	12,550,000	$ 3.12	$ 3.03	$1.1	$(0.1)	$ 0.5	$ (0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	45,000	$23.42	$21.96	$0.1	$ —	$ —	$ —
Receive fixed/pay variable	NGL	45,781	$25.46	$25.39	$0.1	$(0.1)	$ —	$ —
Receive variable/pay variable	Natural Gas	11,843,834	$ 3.08	$ 3.06	$0.2	$ —	$ 0.1	$ —
	NGL	1,262,231	$26.68	$25.59	$1.4	$ —	$ —	$ —
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,193,804	$ 2.93	$ 2.90	$0.1	$ —	$ 0.1	$ —
	NGL	456,250	$23.15	$21.26	$0.8	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,199,798	$ 2.86	$ 2.83	$0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	365,634	$ 3.11	$ 3.08	$—	$ —	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGLs and crude oil are measured in Bbl.

(2) Weighted-average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGLs and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2016, and December 31, 2015, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains of approximately $0.1 million and $0.6 million at September 30, 2016 and December 31, 2015, respectively, as well as cash collateral received.

13. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2016 and December 31, 2015:

	At September 30, 2016						At December 31, 2015	
					Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Strike Price[2]	Market Price[2]	Asset	Liability	Asset	Liability
					(in millions)			
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	414,000	$ 3.75	$ 3.00	$0.3	$ —	$ 2.1	$ —
	NGL	745,200	$39.29	$27.70	$9.2	$ —	$54.4	$ —
	Crude Oil	202,400	$75.91	$49.00	$5.4	$ —	$27.7	$ —
Calls (written)	Natural Gas	414,000	$ 4.98	$ 3.00	$—	$ —	$ —	$ —
	NGL	745,200	$45.09	$27.70	$—	$(0.3)	$ —	$(0.3)
	Crude Oil	202,400	$86.68	$49.00	$—	$ —	$ —	$ —
Puts (written)	Natural Gas	414,000	$ 3.75	$ 3.00	$—	$(0.3)	$ —	$(2.1)
	NGL	59,800	$37.04	$28.98	$—	$(0.6)	$ —	$(1.5)
Calls (purchased)	Natural Gas	414,000	$ 4.98	$ 3.00	$—	$ —	$ —	$ —
	NGL	59,800	$42.09	$28.98	$—	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,642,500	$25.90	$29.51	$5.5	$ —	$ 5.8	$ —
	Crude Oil	638,750	$59.86	$51.66	$7.6	$ —	$10.0	$ —
Calls (written)	NGL	1,642,500	$30.06	$29.51	$—	$(8.0)	$ —	$(0.8)
	Crude Oil	638,750	$68.19	$51.66	$—	$(1.2)	$ —	$(0.6)
Portion of option contracts maturing in 2018								
Puts (purchased)	Crude Oil	91,250	$42.00	$53.58	$0.3	$ —	$ —	$ —
Calls (written)	Crude Oil	91,250	$51.75	$53.58	$—	$(0.8)	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGLs and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGLs and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2016, and December 31, 2015, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment losses of approximately $0.4 million at December 31, 2015 as well as cash collateral received.

14. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of franchise tax laws by the State of Texas that apply to entities organized as partnerships, and which is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas state franchise tax rate to modified gross margin. Our Texas state franchise tax rate was 0.5% and 0.4% for the nine months ended September 30, 2016 and 2015, respectively.

At September 30, 2016 and December 31, 2015, we included a current income tax payable of $1.8 million and $1.1 million, respectively, in ''Property and other taxes payable'' on our consolidated statements of financial position. In addition, at September 30, 2016 and December 31, 2015, we included a deferred income tax payable of $14.8 million and $14.3 million, respectively, in ''Other long-term liabilities'' on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

15. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that are managed separately, since each business segment requires different operating strategies. We conduct our business through two distinct reporting segments:

- Gathering, Processing and Transportation; and
- Logistics and Marketing.

The following tables present certain financial information relating to our business segments and corporate activities:

	For the three months ended September 30, 2016			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$302.3	$261.0	$ —	$563.3
Less: Intersegment revenue	75.1	2.2	—	77.3
Operating revenue	227.2	258.8	—	486.0
Cost of natural gas and natural gas liquids	154.1	249.9	—	404.0
Segment gross margin	73.1	8.9	—	82.0
Operating and maintenance	45.4	9.3	0.2	54.9
General and administrative	15.6	1.4	1.2	18.2
Depreciation and amortization	38.1	1.1	—	39.2
	99.1	11.8	1.4	112.3
Operating loss	(26.0)	(2.9)	(1.4)	(30.3)
Interest expense, net	—	—	(8.5)	(8.5)
Other income	8.3[2]	—	0.1	8.4
Loss before income tax expense	(17.7)	(2.9)	(9.8)	(30.4)
Income tax expense	—	—	(0.7)	(0.7)
Net loss	$ (17.7)	$ (2.9)	$(10.5)	$ (31.1)
Less: Net loss attributable to noncontrolling interest	—	—	(10.4)	(10.4)
Net loss attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ (17.7)	$ (2.9)	$ (0.1)	$ (20.7)

(1) Corporate consists of interest expense, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our equity investment in the Texas Express NGL system.

15. SEGMENT INFORMATION – (continued)

	For the three months ended September 30, 2015			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate(1)	Total
	(in millions)			
Total revenue	$357.7	$520.8	$ —	$878.5
Less: Intersegment revenue	214.3	3.2	—	217.5
Operating revenue	143.4	517.6	—	661.0
Cost of natural gas and natural gas liquids	16.7	506.0	—	522.7
Segment gross margin	126.7	11.6	—	138.3
Operating and maintenance	55.7	18.2	0.1	74.0
General and administrative	17.2	3.0	1.0	21.2
Depreciation and amortization	37.1	2.1	—	39.2
	110.0	23.3	1.1	134.4
Operating income (loss)	16.7	(11.7)	(1.1)	3.9
Interest expense, net	—	—	(7.6)	(7.6)
Other income (loss)	8.9(2)	—	(0.4)	8.5
Income (loss) before income tax expense	25.6	(11.7)	(9.1)	4.8
Income tax expense	—	—	(3.7)	(3.7)
Net income (loss)	$ 25.6	$ (11.7)	$(12.8)	$ 1.1
Less: Net income attributable to noncontrolling interest	—	—	4.7	4.7
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 25.6	$ (11.7)	$(17.5)	$ (3.6)

(1) Corporate consists of interest expense, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our equity investment in the Texas Express NGL system.

15. SEGMENT INFORMATION – (continued)

	As of and for the nine months ended September 30, 2016			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$ 814.5	$761.6	$ —	$1,576.1
Less: Intersegment revenue	214.6	16.0	—	230.6
Operating revenue	599.9	745.6	—	1,345.5
Cost of natural gas and natural gas liquids	393.8	717.3	—	1,111.1
Segment gross margin	206.1	28.3	—	234.4
Operating and maintenance	144.6	29.1	0.3	174.0
General and administrative	43.4	4.2	3.1	50.7
Asset impairment	—	10.6	—	10.6
Depreciation and amortization	114.0	4.7	—	118.7
	302.0	48.6	3.4	354.0
Operating loss	(95.9)	(20.3)	(3.4)	(119.6)
Interest expense, net	—	—	(25.0)	(25.0)
Other income	22.0[2]	—	0.3	22.3
Loss before income tax expense	(73.9)	(20.3)	(28.1)	(122.3)
Income tax expense	—	—	(2.1)	(2.1)
Net loss	(73.9)	(20.3)	(30.2)	(124.4)
Less: Net loss attributable to noncontrolling interest	—	—	(46.7)	(46.7)
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ (73.9)	$ (20.3)	$ 16.5	$ (77.7)
Total assets	$4,754.9[3]	$178.8	$ 48.0	$4,981.7
Capital expenditures (excluding acquisitions)	$ 37.5	$ 2.6	$ 1.1	$ 41.2

(1) Corporate consists of interest expense, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our equity investment in the Texas Express NGL system.

(3) Total assets for our Gathering, Processing and Transportation segment includes $359.6 million for our equity investment in the Texas Express NGL system.

15. SEGMENT INFORMATION – (continued)

	As of and for the nine months ended September 30, 2015			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$1,144.5	$1,975.3	$ —	$3,119.8
Less: Intersegment revenue	776.9	28.3	—	805.2
Operating revenue	367.6	1,947.0	—	2,314.6
Cost of natural gas and natural gas liquids	58.5	1,913.9	—	1,972.4
Segment gross margin	309.1	33.1	—	342.2
Operating and maintenance	161.5	45.1	0.3	206.9
General and administrative	48.5	9.0	3.6	61.1
Goodwill impairment	206.1	20.4	—	226.5
Asset impairment	—	12.3	—	12.3
Depreciation and amortization	112.0	6.3	—	118.3
	528.1	93.1	3.9	625.1
Operating loss	(219.0)	(60.0)	(3.9)	(282.9)
Interest expense, net	—	—	(21.5)	(21.5)
Other income (loss)	20.5[2]	—	(0.2)	20.3
Loss before income tax benefit	(198.5)	(60.0)	(25.6)	(284.1)
Income tax expense	—	—	(1.4)	(1.4)
Net loss	(198.5)	(60.0)	(27.0)	(285.5)
Less: Net loss attributable to noncontrolling interest	—	—	(125.4)	(125.4)
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ (198.5)	$ (60.0)	$ 98.4	$ (160.1)
Total assets	$4,983.0[3]	$ 210.2	$ 97.8	$5,291.0
Capital expenditures (excluding acquisitions)	$ 132.8	$ 11.0	$ 3.6	$ 147.4

(1) Corporate consists of interest expense, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our equity investment in the Texas Express NGL system.

(3) Total assets for our Gathering, Processing and Transportation segment includes $373.7 million for our equity investment in the Texas Express NGL system.

16. SUPPLEMENTAL CASH FLOW INFORMATION

In the ‘‘Cash used in investing activities’’ section of the consolidated statements of cash flows, we exclude changes that did not affect cash. The following is a reconciliation of cash used for additions to property, plant and equipment to total capital expenditures (excluding ‘‘Acquisitions’’ and ‘‘Investment in joint ventures’’):

	For the nine months ended September 30,	
	2016	2015
	(in millions)	
Total capital expenditures	$41.2	$147.4
Decrease in construction payables	11.6	8.0
Cash used for additions to property, plant and equipment	$52.8	$155.4

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

Since May 2014, the Financial Accounting Standards Board, or FASB, has issued ASU Nos. 2014-09, 2015-14, 2016-08, 2016-10 and 2016-12 which outline a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The accounting updates are effective for annual and interim periods beginning on or after December 15, 2017, and may be applied on either a full or modified retrospective basis. We are currently evaluating our revenue contracts and determining the impacts that the new pronouncement will have on our consolidated financial statements and disclosures. We are also currently evaluating which transition approach we will apply.

Leases

In February 2016, the FASB issued ASU No. 2016-02, which requires lessees to recognize a right-of-use asset and a lease liability on the balance sheet for practically all leases (other than leases that are less than 12 months). The pronouncement continues to require lessees to distinguish between operating and financing, formerly known as capital leases, and lessors to distinguish between sales-type, direct financing, and operating leases for income statement purposes. This accounting update is effective for annual periods, and for interim periods within those annual periods, beginning after December 15, 2018. Early adoption is permitted, and entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach with certain optional practical expedients. We are currently evaluating the impact that this pronouncement will have on our consolidated financial statements.

18. SUBSEQUENT EVENTS

Distribution to Partners

On October 27, 2016, the board of directors of Midcoast Holdings, our General Partner, declared a cash distribution payable to our unitholders on November 14, 2016. The distribution will be paid to unitholders of record as of November 7, 2016, of our available cash of $16.5 million at September 30, 2016, or $0.3575 per limited partner unit. We will pay $7.6 million to our public Class A common unitholders, while $8.9 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, with respect to its general partner interest.

Midcoast Operating Distribution

On October 27, 2016, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable on November 14, 2016 to its partners of record as of November 7, 2016. Midcoast Operating will pay $26.0 million to us and $14.4 million to EEP.

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

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* and in conjunction with the audited consolidated financial statements and accompanying notes in our Annual Report on Form 10-K for the year ended December 31, 2015, as filed with the SEC on February 17, 2016.

RESULTS OF OPERATIONS — OVERVIEW

We are a growth-oriented Delaware limited partnership formed by EEP to serve as EEP's primary vehicle for owning and growing its natural gas and NGL midstream business in the United States. Midcoast Operating is a Texas limited partnership that owns a network of natural gas and NGL gathering and transportation systems, natural gas processing and treating facilities and an NGL fractionation facility primarily located in Texas and Oklahoma. Midcoast Operating also owns and operates NGL and condensate logistics and marketing assets that primarily support its gathering, processing and transportation business. Through our ownership of Midcoast Operating's general partner, we control, manage and operate these systems.

We gather natural gas from the wellhead and central receipt points on our systems, deliver it to our facilities for processing and treating and redeliver the residue gas to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies. We deliver the NGLs produced at our processing plants to intrastate pipelines and interstate pipelines for transportation to the NGL market hubs in Mont Belvieu, Texas and Conway, Kansas. We also deliver a portion of NGLs produced at our fractionation facility at one of our processing plants to a wholesale customer. In addition, we provide marketing services of natural gas and NGLs to wholesale customers.

Our financial condition and results of operations are subject to variability from multiple factors, including:

- the volumes of natural gas, NGLs, condensate, and crude oil that we gather, process and transport on our systems;
- the price of natural gas, NGLs, condensate, and crude oil that we pay for and receive in connection with the services we provide;
- our ability to replace or renew existing contracts; and
- the supply and demand for natural gas, NGLs, condensate, and crude oil.

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing. We have established these reporting segments as strategic business units to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for the periods presented:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating income (loss)				
Gathering, Processing and Transportation	$(26.0)	$ 16.7	$ (95.9)	$(219.0)
Logistics and Marketing	(2.9)	(11.7)	(20.3)	(60.0)
Corporate	(1.4)	(1.1)	(3.4)	(3.9)
Total operating income (loss)	(30.3)	3.9	(119.6)	(282.9)
Interest expense, net	(8.5)	(7.6)	(25.0)	(21.5)
Other income	8.4	8.5	22.3	20.3
Income tax expense	(0.7)	(3.7)	(2.1)	(1.4)
Net income (loss)	$(31.1)	$ 1.1	$(124.4)	$(285.5)

Derivative Transactions and Hedging Activities

Contractual arrangements in our Gathering, Processing and Transportation segment and our Logistics and Marketing segment expose us to market risks associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We use derivative financial instruments such as futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with market fluctuations in commodity prices, as well as to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. Derivative financial instruments that do not receive hedge accounting under the provisions of authoritative accounting guidance create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not receive hedge accounting in our consolidated statements of income as ''Operating revenue'' and ''Cost of natural gas and natural gas liquids.''

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Gathering, Processing and Transportation segment:				
Hedge ineffectiveness	$ —	$ (0.1)	$ —	$ (4.1)
Non-qualified hedges	(16.8)	10.1	(82.6)	(31.4)
Logistics and Marketing segment:				
Non-qualified hedges	2.2	(3.9)	(4.9)	(18.0)
Derivative fair value net gains (losses)	$(14.6)	$ 6.1	$(87.5)	$(53.5)

RESULTS OF OPERATIONS — BY SEGMENT

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, condensate stabilizers and an NGL fractionation facility. Revenues for our gathering, processing and transportation business are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our systems; the volumes of NGLs sold; and the level of natural gas, NGL and condensate prices. The segment gross margin of our gathering, processing and transportation business, which we define as revenue generated from gathering, processing and transportation operations less the cost of natural gas and natural gas liquids purchased, is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing our services, in addition to the proceeds we receive for the sales of natural gas, NGLs and condensate to affiliates and third parties.

The following tables set forth the operating results of our Gathering, Processing and Transportation segment and approximate average daily volumes of natural gas throughput and NGLs produced on our major systems for the periods presented:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating revenues	$ 227.2	$ 143.4	$ 599.9	$ 367.6
Cost of natural gas and natural gas liquids	154.1	16.7	393.8	58.5
Segment gross margin	73.1	126.7	206.1	309.1
Operating and maintenance	45.4	55.7	144.6	161.5
General and administrative	15.6	17.2	43.4	48.5
Goodwill impairment	—	—	—	206.1
Depreciation and amortization	38.1	37.1	114.0	112.0
Operating expenses	99.1	110.0	302.0	528.1
Operating income (loss)	(26.0)	16.7	(95.9)	(219.0)
Other income	8.3	8.9	22.0	20.5
Net income (loss)	$ (17.7)	$ 25.6	$ (73.9)	$ (198.5)
Operating Statistics (MMBtu/d):				
East Texas	894,000	966,000	924,000	981,000
Anadarko	606,000	760,000	632,000	794,000
North Texas	192,000	262,000	202,000	274,000
Total	1,692,000	1,988,000	1,758,000	2,049,000
NGL Production (Bpd)	67,588	85,343	70,932	82,498

Three months ended September 30, 2016, compared with the three months ended September 30, 2015

The operating income of our Gathering, Processing and Transportation segment for the three months ended September 30, 2016, decreased by $42.7 million, as compared to the same period in 2015, primarily as a result of lower segment gross margin in the 2016 period, as discussed below.

Segment gross margin decreased by approximately $53.6 million for the three months ended September 30, 2016, as compared to the same period in 2015, in part due to non-cash, mark-to-market activity. Segment gross margin experienced a net decrease of $26.8 million due to non-cash, mark-to-market losses of $16.8 million for the three months ended September 30, 2016, as compared to gains of $10.0 million for the same period in 2015. These derivative losses are primarily related to the increased commodity prices of condensate and NGLs period over period.

Segment gross margin decreased by approximately $13.5 million for the three months ended September 30, 2016, as compared to the same period in 2015, due to reduced natural gas throughput. The average daily volumes of our major systems for the three months ended September 30, 2016 decreased by 296,000 MMBtu/d, or 15%, when compared to the same period in 2015. The average NGL production for the three months ended September 30, 2016, decreased by 17,755 Bpd, or 21%, when compared to the same period in 2015. The decrease in volumes was primarily attributable to continued low commodity prices for natural gas, condensate and NGLs, which resulted in reductions in drilling activity from producers in the areas we operate.

Segment gross margin decreased $4.6 million for the three months ended September 30, 2016, as compared to the same period in 2015, due to a decrease in processing margins primarily driven by lower NGL prices along with a decline in NGL volumes, primarily in the Anadarko region.

Segment gross margin decreased $3.1 million for the three months ended September 30, 2016, as compared to the same period in 2015, due to decreased margins from lower NGL prices, net of hedges, related to contracts where we were paid in commodities for our services.

Operating and maintenance and general and administrative costs combined decreased $11.9 million for the three months ended September 30, 2016, as compared to the same period in 2015, primarily due to continued cost reduction efforts, including decreases in repairs and maintenance and contract labor. Also included in the period over period decrease is a $2.1 million property tax refund.

Increases in ''Operating revenues'' and ''Cost of natural gas and natural gas liquids'' for the three months ended September 30, 2016, are primarily due to increased natural gas sales directly to third parties instead of through the Logistics and Marketing segment.

Nine months ended September 30, 2016, compared with the nine months ended September 30, 2015

The operating loss of our Gathering, Processing and Transportation segment for the nine months ended September 30, 2016 decreased $123.1 million, as compared to the same period of 2015, primarily as a result of a $206.1 million goodwill impairment charge that was recorded during the nine months ended September 30, 2015. No similar charge was recorded during the same period in 2016. The effects of the lack of impairment charge were offset by lower segment gross margin in the 2016 period, as discussed below.

Segment gross margin decreased $103.0 million for the nine months ended September 30, 2016, as compared to the same period in 2015, in part due to increased non-cash, mark-to-market losses. Non-cash, mark-to-market losses increased $47.1 million for the nine months ended September 30, 2016, as compared to the same period in 2015. These derivative losses are primarily related to the increased commodity prices of condensate and NGLs period over period, as well as losses from the reversal of previously recognized unrealized mark-to-market gains when the underlying transactions were settled.

Segment gross margin decreased by approximately $32.1 million for the nine months ended September 30, 2016, as compared to the same period in 2015, due to reduced natural gas production volumes. The average daily volumes of our major systems for the nine months ended September 30, 2016, decreased by approximately 291,000 MMBtu/d, or 14%, when compared with the same period in 2015. The average NGL production for the nine months ended September 30, 2016, decreased 11,566 Bpd, or 14%, compared to the same period in 2015. The decrease in volumes was primarily attributable to the continued low commodity price environment for natural gas and condensate, which resulted in reductions in drilling activity by producers in the areas we operate.

Segment gross margin decreased $10.6 million for the nine months ended September 30, 2016, as compared to the same period in 2015, due to a decrease in processing margins primarily driven by lower NGL prices along with a decline in NGL volumes and associated keep whole volumes in the Anadarko and East Texas regions.

Segment gross margin decreased $12.9 million for the nine months ended September 30, 2016, as compared to the same period in 2015, due to decreased margins from lower NGL prices, net of hedges, related to contracts where we were paid in commodities for our services.

Operating and maintenance and general and administrative costs combined decreased $22.0 million for the nine months ended September 30, 2016, as compared with the same period in 2015, primarily due to continued cost reduction efforts, as discussed above. Operating and maintenance and general and administrative costs combined also decreased due to gains of $5.6 million recorded during the nine months ended September 30, 2016, to recognize return of escrow funds and a reversal of a contingent liability related to an acquisition. For further details regarding these amounts, refer to Item 1. *Financial Statements*, Note 3. *Acquisitions*. In addition, during the nine months ended September 30, 2016, we benefited from a net gain of $1.5 million from indemnification payments received for legal expenses associated with the acquisition of title to right-of-way assets. For more information, refer to Item 1. *Financial Statements*, Note 11. *Related Party Transactions*.

Increases in ''Operating revenues'' and ''Cost of natural gas and natural gas liquids'' for the nine months ended September 30, 2016, are primarily due to increased natural gas sales directly to third parties instead of through the Logistics and Marketing segment.

Future Prospects for Gathering, Processing and Transportation

Demand for our midstream services primarily depends upon the supply of natural gas and associated natural gas from crude oil development and the drilling rate for new wells. Demand for these services depends on overall economic conditions and commodity prices. Commodity prices for natural gas, NGLs, condensate, and crude oil continue to remain low. The depressed commodity price environment is the most significant factor for reduced drilling activity and low volumes in the basins in which we operate. Due to the commodity price environment, we expect drilling activity to remain low, and as a result, we expect to see continued low volumes on our systems in

2016, and beyond. In addition, we also expect our average NGL transportation commitments on the Texas Express system to increase from 29,000 Bpd in 2016 to 75,000 Bpd in 2017.

We have a hedging program in place to assist in mitigating our direct commodity risk. We have hedged over 90% and 60% of our direct forecasted commodity cash flow exposure for 2016 and 2017, respectively. Our condensate and NGL hedge prices for 2017 are approximately 20% and on average 30% lower than 2016, respectively. See *Liquidity and Capital Resources — Derivative Activities* below. Despite our hedging program, we still bear indirect commodity price exposure as lower drilling activity impacts the volumes on our systems as well as direct commodity price exposure for unhedged commodity positions. We expect this indirect impact on our volumes to fluctuate depending on future price movements.

We have sought to expand our natural gas gathering and processing services by: (1) capturing opportunities within our footprint, (2) expanding outside of our existing footprint through strategic acquisitions, (3) providing an array of services for both natural gas and NGLs in combination with core asset optimization, and (4) capitalizing on new market opportunities by diversifying geographically and by commodity composition. However, in light of the low commodity price environment and the ongoing challenges it presents to our business, we are working with EEP to explore and evaluate a broad range of strategic alternatives in addition to, or as alternatives to, our long-term expansion strategies to address these challenges. EEP has also indicated that it is reviewing strategic alternatives with respect to its investment in us and Midcoast Operating. The additional various strategic alternatives may include, but are not necessarily limited to: asset sales; mergers, joint ventures, reorganizations or recapitalizations; and further reductions in operating and capital expenditures. The evaluation process is ongoing, and no decision on any particular strategic alternative has been reached. Enbridge, our ultimate parent, recently announced a merger with Spectra Energy Corp. and has indicated that as part of the integration resulting from the Spectra merger, its existing U.S. sponsored vehicles, which includes us, will be reviewed in context of the combined enterprise. In addition, under the merger agreement, Enbridge has agreed that it and its subsidiaries, including us, will conduct their businesses in the ordinary course prior to completing the merger transaction, subject to certain specified exceptions or the consent of Spectra Energy. Thus, while we continue to progress our strategic evaluation to address the challenges in our natural gas business, it is possible that the evaluation and potential execution of any such strategies could be affected by the merger and extend into 2017.

Logistics and Marketing

The primary role of our logistics and marketing business is to provide marketing services of natural gas, NGLs and condensate received from our gathering, processing and transportation business. We purchase and receive natural gas, NGLs and other products from pipeline systems and processing plants and sell and deliver them to wholesale customers, distributors, refiners, fractionators, chemical facilities, various third parties and end users. Our Logistics and Marketing segment derives a majority of its operating income from selling natural gas, NGLs and condensate received from producers on our Gathering, Processing and Transportation segment pipeline assets. A majority of the natural gas and NGLs we purchase are produced in Texas markets where we have expanded third-party pipeline deliverability alternatives over the past several years. We use our connectivity to interstate pipelines to improve value for producers by delivering natural gas into premium markets and NGLs to primary markets where we sell them to major customers. Additionally, our Logistics and Marketing segment derives operating income from providing logistics services for our customers from the wellhead to markets.

On August 15, 2016, we sold certain trucks, trailers and related facilities in our Logistics and Marketing segment and recognized a loss on disposal of $1.9 million for the three and nine months ended September 30, 2016. For further details, refer to Item 1. *Financial Statements*, Note 6. *Property, Plant and Equipment*. Our Logistics and Marketing segment will contract with third parties to transport NGLs and condensate by truck.

On September 1, 2015, two wholly-owned subsidiaries of Midcoast Operating in the Logistics and Marketing segment sold certain natural gas inventories and assigned certain storage agreements, transportation contracts and other arrangements to a third-party. Since that date, Midcoast Operating subsidiaries have sold their natural gas products directly to third parties instead of through the Logistics and Marketing segment, which has seen reduced activity related to the sale of natural gas products as a result. The arrangement for Midcoast Operating subsidiaries to sell natural gas products directly to third parties expired on October 31, 2016. Starting in the fourth quarter of 2016, we expect that Midcoast Operating subsidiaries will sell their natural gas products to third parties through the Logistics and Marketing segment.

The following table sets forth the operating results of our Logistics and Marketing segment for the periods presented:

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating revenues	$258.8	$517.6	$745.6	$1,947.0
Cost of natural gas and natural gas liquids	249.9	506.0	717.3	1,913.9
Segment gross margin	8.9	11.6	28.3	33.1
Operating and maintenance	9.3	18.2	29.1	45.1
General and administrative	1.4	3.0	4.2	9.0
Goodwill impairment	—	—	—	20.4
Asset impairment	—	—	10.6	12.3
Depreciation and amortization	1.1	2.1	4.7	6.3
Operating expenses	11.8	23.3	48.6	93.1
Operating loss	$ (2.9)	$ (11.7)	$ (20.3)	$ (60.0)

Three months ended September 30, 2016, compared with the three months ended September 30, 2015

The operating loss of our Logistics and Marketing segment for the three months ended September 30, 2016 decreased $8.8 million, as compared to the same period in 2015, primarily as a result of lower operating and maintenance and general and administrative costs, partially offset by lower segment gross margin, as discussed below. Decreases in ''Operating revenues'' and ''Cost of natural gas and natural gas liquids'' for the three months ended September 30, 2016, as compared to the same period in 2015, are primarily due to decreases in commodity prices, the resulting decrease in volumes from reduced drilling activities, and Midcoast Operating subsidiaries' direct sale of their natural gas products to third parties instead of through the Logistics and Marketing segment, as discussed above.

Segment gross margin decreased by $2.7 million for the three months ended September 30, 2016, as compared to the same period in 2015, primarily due to a decrease in storage margins of $12.5 million as a result of the sale of liquids product inventory at lower prevailing market prices relative to the cost of product inventory and lower volumes.

Decreases in segment gross margin were offset by an increase of $7.6 million for the three months ended September 30, 2016, as compared to the same period in 2015, due to costs that were incurred associated with the sale of certain natural gas inventories, and assignment of certain storage agreements, transportation contracts and other arrangements to a third party in September 2015 that were not incurred during the same period in 2016.

Decreases in segment gross margin were also offset by an increase of $6.1 million for non-cash, mark-to-market activity for the three months ended September 30, 2016, as compared to the same period in 2015. This change is primarily related to greater reversals of previously recognized unrealized mark-to-market losses as the underlying transactions were settled, partially offset by losses from the increased commodity prices of NGLs period over period.

Operating and maintenance and general and administrative costs combined decreased $10.5 million for the three months ended September 30, 2016, as compared to the same period in 2015. These decreases are primarily due to workforce reductions, decreases in repairs and maintenance, and other costs savings related to the assignment of certain natural gas arrangements to a third party during the third quarter of 2015, as well as other general cost reduction efforts.

Nine months ended September 30, 2016, compared with the nine months ended September 30, 2015

The operating loss for our Logistics and Marketing segment decreased by $39.7 million for the nine months ended September 30, 2016, as compared to the same period in 2015, in part as a result of a $20.4 million goodwill impairment charge that was recognized during the nine months ended September 30, 2015. No such goodwill impairment charge was recognized during the same period of 2016. The decrease in operating loss was also the result of a $20.8 million decrease in operating and maintenance and general and administrative expenses combined, as discussed below. These changes were offset by a decrease in segment gross margin, as discussed below. Decreases in ''Operating revenues'' and ''Cost of natural gas and natural gas liquids'' for the nine months ended September 30, 2016, as compared to the same period in 2015, are due to the reasons discussed above.

Segment gross margin decreased $4.8 million for the nine months ended September 30, 2016, as compared to the same period in 2015, primarily due to a decrease in storage margins of $12.2 million as a result of the sale of liquids product inventory at lower prevailing market prices relative to the cost of product inventory.

Segment gross margin decreased $10.9 million for the nine months ended September 30, 2016, as compared to the same period in 2015, related to dispositions and other transactions that occurred in 2015. In the third quarter of 2015, we sold our non-core Tinsley system and assigned certain storage agreements, transportation contracts and other arrangements to third parties. As a result, the segment margin generated by these assets for the nine months ended September 30, 2015 was not present in the same period of 2016.

Decreases in segment gross margin were offset by an increase of $7.6 million for the nine months ended September 30, 2016, as compared to the same period in 2015, due to costs that were incurred associated with the sale of certain natural gas inventories, and assignment of certain storage agreements, transportation contracts and other arrangements to a third party in September 2015 that were not incurred during the same period in 2016.

Decreases in segment gross margin were also offset by a decrease in non-cash, mark-to-market losses of $13.1 million for the nine months ended September 30, 2016, as compared to the same period in 2015. This change is primarily related to greater reversals of previously recognized unrealized mark-to-market losses as the underlying transactions were settled, partially offset by losses from the increased commodity prices of NGLs period over period.

Operating and maintenance and general and administrative costs combined decreased $20.8 million for the nine months ended September 30, 2016, as compared to the same period in 2015. These decreases are primarily due to workforce reductions, decreases in repairs and maintenance, and other costs savings related to the assignment of certain natural gas arrangements to a third party during the third quarter of 2015, as well as other general cost reduction efforts.

Corporate

Our corporate results consist of interest expense and other costs such as income taxes, which are not allocated to the business segments.

	For the three months ended September 30,		For the nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating and maintenance	$ 0.2	$ 0.1	$ 0.3	$ 0.3
General and administrative	1.2	1.0	3.1	3.6
Operating expenses	1.4	1.1	3.4	3.9
Operating loss	(1.4)	(1.1)	(3.4)	(3.9)
Interest expense, net	(8.5)	(7.6)	(25.0)	(21.5)
Other income (loss)	0.1	(0.4)	0.3	(0.2)
Loss before income tax expense	(9.8)	(9.1)	(28.1)	(25.6)
Income tax expense	(0.7)	(3.7)	(2.1)	(1.4)
Net loss	$(10.5)	$(12.8)	$(30.2)	$(27.0)

Three months ended September 30, 2016, compared with the three months ended September 30, 2015

Net loss in our Corporate segment decreased $2.3 million for the three months ended September 30, 2016, as compared to the same period in 2015. The decrease was a result of a decrease in income tax expense of $3.0 million. In 2015, we assigned certain storage agreements, transportation contracts and other agreements to a third party and recognized an additional $2.4 million deferred income tax expense during the three months ended September 30, 2015. This transaction increased our apportionment factor for the Texas state franchise tax, which increased our deferred income tax expense in 2015. The decrease in income tax expense was partially offset by an increase of $0.9 million in interest expense, primarily due to an increase in our average outstanding long-term debt balance on our Credit Agreement.

Nine months ended September 30, 2016, compared with the nine months ended September 30, 2015

Net loss in our Corporate segment increased $3.2 million for the nine months ended September 30, 2016, as compared to the same period in 2015. The increase was a result of an increase in interest expense of $3.5 million, primarily due to an increase in our average outstanding long-term debt balance on our Credit Agreement. In addition, income tax expense increased by $0.7 million due to a 2015 tax benefit from a reduction in deferred income tax payable caused by a reduction in the Texas state franchise tax rate from the Texas House Bill 32. This reduction was partially offset by an increase in deferred income taxes in 2015 due to an increase in our apportionment factor for the Texas state franchise tax, as described above.

LIQUIDITY AND CAPITAL RESOURCES

Our primary ongoing sources of liquidity include cash generated from operations of Midcoast Operating and borrowings under our senior revolving credit facility, which we refer to as the Credit Agreement. Depending on market conditions and other factors, we may also rely on issuances of additional debt and equity securities.

In light of the low commodity price environment and the ongoing challenges it presents to our business, we will continue to evaluate opportunities to strengthen our business. Evaluation of strategic alternatives may include, but is not limited to: asset sales; mergers, joint ventures, reorganizations or recapitalizations; and further reductions in operating and capital expenditures as discussed above under *Future Prospects for Gathering, Processing and Transportation*.

Equity and Debt Financing Activities

Credit Agreement

Our primary source of liquidity is provided by the Credit Agreement. We, Midcoast Operating, and our material subsidiaries are parties to the Credit Agreement, which permits aggregate borrowings of up to, at any one time outstanding, $810.0 million. The original term of the Credit Agreement was three years subject to four one-year requests for extensions at the lenders' discretion, two of which we have utilized. Our Credit Agreement's current maturity date is September 30, 2018; however, $140.0 million of commitments will expire on the initial maturity date of November 13, 2016 and an additional $25.0 million of commitments will expire on September 30, 2017.

At September 30, 2016, we had $450.0 million in outstanding borrowings under the Credit Agreement at a weighted-average interest rate of 3.43%. Under the Credit Agreement, we had net repayments of approximately $40.0 million during the nine months ended September 30, 2016, which includes gross borrowings of $5,715.0 million and gross repayments of $5,755.0 million.

Our Credit Agreement requires compliance with two financial covenants. We are not permitted to allow our ratio of consolidated funded debt to pro forma earnings before interest, taxes, depreciation and amortization, or EBITDA, as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We must also maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

At September 30, 2016, we were in compliance with the terms of our financial covenants in the Credit Agreement, and we expect to remain in compliance throughout the remainder of 2016. Due to the low commodity price environment and the potential implications on our results of operations, it is possible that we may not be able to meet the total leverage ratio financial covenant at some point during the term of the agreement without further action on our part. If this were to occur, we would seek a waiver from our lenders, seek additional capital contributions, pursue refinancing of the amounts outstanding under the Credit Agreement or seek to take other action to prevent a default under the Credit Agreement, although there is no assurance that we could obtain any such necessary preventative actions. Failure to comply with one or both of the financial covenants may result in the occurrence of an event of default under the Credit Agreement, which would result in a cross-default under the note purchase agreement relating to our senior notes. If an event of default were to occur, the lenders could, among other things, terminate their commitments under the Credit Agreement, demand immediate payment of all amounts borrowed by us and Midcoast Operating, trigger the springing liens, and require adequate security or collateral for all outstanding letters of credit outstanding under the facility. In addition, we and Midcoast Operating are restricted under the Credit Agreement from making distributions if there is a continuing default under certain covenants, including the financial covenants. Any restrictions in our revolving credit facility could adversely affect our business, financial condition, and results of operations. See Item 1A. *Risk Factors — Risks Related to Our Business* in our Annual Report on Form 10-K for fiscal year ended December 31, 2015.

Available Liquidity

The following table sets forth liquidity sources at September 30, 2016:

	(in millions)
Total commitments under Credit Agreement	810.0
Amounts outstanding under Credit Agreement	(450.0)
Total	$ 360.0

As of September 30, 2016, we had a working capital deficit of approximately $105.4 million and approximately $360.0 million of liquidity (subject to Credit Agreement covenant compliance), as shown above, to meet our ongoing operational, investment and financing needs. For further details regarding our cash flow analysis, refer to *Liquidity and Capital Resources — Cash Flow Analysis* below.

Funding Arrangements with EEP

During any quarter until the quarter ending December 31, 2017, if our quarterly declared distribution exceeds our distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement, we receive an increased quarterly distribution from Midcoast Operating, and EEP receives a corresponding reduction to its quarterly distribution in the amount that our declared distribution exceeds our distributable cash. Midcoast Operating's adjustment of EEP's distribution is limited by EEP's pro rata share of the Midcoast Operating quarterly cash distribution and a maximum of $0.005 per unit quarterly distribution increase by us. There is no requirement for us to compensate EEP for these adjusted distributions, except for settling our capital accounts with Midcoast Operating in a liquidation scenario. For the three and nine months ended September 30, 2016, EEP's quarterly distribution from Midcoast Operating was reduced by $5.1 million and $8.2 million, respectively, in accordance with the amended agreement described above.

To the extent we continue to have declared distributions each quarter at the current distribution level, we expect that EEP will continue to receive quarterly reductions in its distributions from Midcoast Operating in the fourth quarter of 2016. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions in this or any other amount, and our General Partner has considerable discretion to determine the amount of our available cash each quarter. In addition, our General Partner may change our cash distribution policy at any time, subject to the requirement in our partnership agreement to distribute all of our available cash quarterly. For further discussion of risks related to our distribution, see Item 1A. *Risk Factors — Risks Related to Our Business* in our Annual Report on Form 10-K for fiscal year ended December 31, 2015.

Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually.

In addition, Midcoast Operating is party to a Financial Support Agreement with EEP, pursuant to which EEP provides letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of financial obligations of Midcoast Operating and its wholly-owned subsidiaries under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly-owned subsidiaries, is a party. At September 30, 2016, EEP provided no letters of credit and $24.8 million in guarantees. Midcoast Operating incurs a 2.5% annual fee based on the cumulative average amount of letters of credit and guarantees outstanding under this agreement. Midcoast Operating incurred $0.4 million of these costs for the nine months ended September 30, 2016. For further details regarding the Financial Support Agreement, refer to Item 1. *Financial Statements*, Note 11. *Related Party Transactions*.

Sale of Accounts Receivable

We and certain of our subsidiaries are parties to a receivables purchase arrangement, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of participating sellers, consisting of certain of our subsidiaries and certain EEP subsidiaries up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. The Receivables Agreement was amended in June 2016 to extend the termination date of the agreement to December 31, 2019.

We sold and derecognized receivables to an indirect wholly-owned subsidiary of Enbridge for $421.9 million and $1,161.0 million for the three and nine months ended September 30, 2016, respectively. As a result, we received cash proceeds of $421.7 million and $1,160.5 million for the three and nine months ended September 30, 2016, respectively. As of September 30, 2016, outstanding receivables of $143.8 million, which had been sold and derecognized, had not been collected on behalf of the Enbridge subsidiary.

For further details regarding the Receivables Agreement, refer to Item 1. *Financial Statements*, Note 11. *Related Party Transactions*.

Cash Requirements

Senior Notes

We have $400.0 million of notes consisting of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, and commenced on March 31, 2015.

The Notes were issued pursuant to a Note Purchase Agreement, or the Purchase Agreement, between us and the purchasers named therein. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed by each of our material subsidiaries pursuant to a guaranty agreement. Until such time as we obtain an investment grade rating from either Moody's or S&P and upon certain trigger events, we and the guarantors will grant liens in our assets (subject to certain excluded assets) to secure the obligations under the Notes. There are currently no liens associated with the Notes.

The Purchase Agreement also requires compliance with two financial covenants. We must not permit the ratio of consolidated funded debt to pro forma Earnings before Interest, Taxes, Depreciation and Amortization, or EBITDA, (the total leverage ratio), as of the end of any applicable four-quarter period to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We also must maintain, on a consolidated basis, as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

At September 30, 2016, we were in compliance with the terms of our financial covenants under the Notes and the related Purchase Agreement, and we expect to remain in compliance throughout the remainder of 2016. Due to the low commodity price environment and the potential implications on our results of operations, it is possible that we may not be able to meet the total leverage ratio financial covenant at some point during the term of the agreement without further action on our part. If this were to occur, we would seek a waiver from the note holders, seek additional capital contributions, pursue refinancing of the amounts outstanding under the Notes or seek to take other action to prevent a default under the Purchase Agreement and the Notes, although there is no assurance that we could obtain any such necessary preventative actions. Any failure to comply with one or both of the financial covenants could result in an event of default under the Purchase Agreement and the Notes and result in a cross-default under the Credit Agreement. If an event of default were to occur, the note holders could, among other things, demand immediate payment of the Notes and trigger the springing liens. In addition, we and Midcoast Operating are restricted under the Credit Agreement from making distributions if there is a continuing default under certain covenants, including the financial covenants. Any restrictions in our revolving credit facility could adversely affect our business, financial condition, and results of operations.

Capital Spending

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful life. Examples of maintenance capital expenditures include expenditures to replace pipelines or processing facilities, to maintain equipment reliability, integrity and safety or to comply with existing governmental regulations and industry standards. We also include in maintenance capital expenditures a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund our proportionate share of maintenance capital expenditures through operating cash flows.

Expansion capital expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards. Examples of expansion capital expenditures include the acquisition of additional assets or businesses, as well as capital projects that improve the service, integrity and safety capability of our existing assets, increase operating capacities or revenues, reduce operating costs from existing levels, or enable us to comply with new governmental regulations or industry standards. We anticipate funding our proportionate share of expansion capital expenditures temporarily through borrowings under the Credit Agreement, with long-term debt and equity funding being obtained when needed and as market conditions allow.

Capital projects at Midcoast Operating are currently funded by us and by EEP based on our proportionate ownership percentages in Midcoast Operating, which are 51.6% and 48.4%, respectively. Under Midcoast Operating's partnership agreement, we and EEP each have the option to contribute our proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund expansion capital expenditures or other growth projects. To the extent that we or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions to Midcoast Operating to the extent necessary to fully fund such expenditures in exchange for additional ownership interests in Midcoast Operating. For the nine months ended September 30, 2016, EEP provided approximately $8.1 million to fund its share of enhancement projects.

If EEP elects not to fund any capital expenditures at Midcoast Operating, we will have the option to fund all or a portion of EEP's proportionate share of such capital expenditures in exchange for additional interests in Midcoast Operating. As a result, if our interests in Midcoast Operating increase, our proportionate share of the capital expenditures incurred by Midcoast Operating will also increase proportionate to our interest in Midcoast Operating. To the extent that EEP elects not to fund all or a portion of its proportionate share of Midcoast Operating's capital expenditures, and we elect not to fund any capital expenditures not funded by EEP, we expect that Midcoast Operating will not pursue the applicable capital projects associated with such unfunded capital expenditures.

We incurred capital expenditures of $41.2 million for the nine months ended September 30, 2016, including $20.5 million of maintenance capital activities. At September 30, 2016, we had approximately $7.6 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment in the future.

Acquisitions

Subject to our strategic review and other matters, as discussed above under *Future Prospects for Gathering, Processing and Transportation*, we may continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We would expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under the Credit Agreement, joint ventures and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

In addition, if and when market conditions improve and our financing capacity increases, EEP has indicated that it may offer us the opportunity to purchase additional interests in Midcoast Operating from time to time. These acquisitions sometimes referred to as "drop-down" transactions, will provide an alternative source of funding for EEP while at the same time providing an opportunity for meaningful growth in our cash flows. However, EEP is under no obligation to offer to sell us additional interests in Midcoast Operating, and we are under no obligation to buy any such additional interests.

Forecasted Expenditures

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth Midcoast Operating's estimated maintenance and expansion capital expenditures of $30.0 million, net of joint funding from EEP, for the year ending December 31, 2016. Although we anticipate making these expenditures in 2016, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets.

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Compression Capital	$ 5
Well-connect Expansion Capital	15
Expansion Capital	10
Maintenance Capital Expenditure Activities	30
	60
Less: Joint Funding from:	
EEP[(1)]	30
	$30

(1) Joint funding is based upon EEP's current 48.4% ownership of Midcoast Operating.

Derivative Activities

We record all derivative financial instruments at fair market value in our consolidated statements of financial position. Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at September 30, 2016, for each of the indicated calendar years:

	Notional[1]	2016	2017	2018	2019	2020 & Thereafter	Total[2]
				(in millions)			
Swaps:							
Natural gas	19,263,317	$ 0.2	$ 1.0	$ —	$ —	$—	$ 1.2
NGL	13,241,900	0.1	(2.1)	—	—	—	(2.0)
Crude Oil	1,679,300	0.3	(0.4)	—	—	—	(0.1)
Options:							
Natural gas – puts purchased	414,000	0.3	—	—	—	—	0.3
Natural gas – puts written	414,000	(0.3)	—	—	—	—	(0.3)
Natural gas – calls written	414,000	—	—	—	—	—	—
Natural gas – calls purchased	414,000	—	—	—	—	—	—
NGL – puts purchased	2,387,700	9.2	5.5	—	—	—	14.7
NGL – puts written	59,800	(0.6)	—	—	—	—	(0.6)
NGL – calls written	2,387,700	(0.3)	(8.0)	—	—	—	(8.3)
NGL – calls purchased	59,800	—	—	—	—	—	—
Crude Oil – puts purchased	932,400	5.4	7.6	0.3	—	—	13.3
Crude Oil – calls written	932,400	—	(1.2)	(0.8)	—	—	(2.0)
Forward contracts:							
Natural gas	36,413,904	(0.2)	0.2	0.1	0.1	—	0.2
NGL	8,091,589	0.3	1.5	0.8	—	—	2.6
Crude Oil	383,298	(1.5)	—	—	—	—	(1.5)
Totals		$12.9	$ 4.1	$ 0.4	$0.1	$—	$17.5

(1) Notional amounts for natural gas are recorded in MMBtu, where as NGLs and crude oil are recorded in Bbl.

(2) Fair values exclude credit valuation adjustment gains of approximately $0.1 million at September 30, 2016.

Subordinated Units

EEP through its ownership of our General Partner owns all of our subordinated units. For any quarter during the subordination period, holders of the subordinated units will not be entitled to receive any distribution until holders of Class A common units have received the minimum quarterly distribution for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters during the subordination period. Subordinated units will not accrue arrearages and holders of Class A common units will receive a special allocation of gross income for each taxable year during which subordinated units are outstanding that would otherwise be allocable to holders of subordinated units.

When the subordination period ends, the outstanding subordinated units will convert into a new class of common units, which we refer to as Class B common units, on a one-for-one basis, and all Class A common units will no longer be entitled to arrearages. We expect that the subordination period will end on the day after the distribution is paid relative to the fourth quarter 2016 results.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the periods indicated:

	For the nine months ended September 30, 2016	2015	Variance 2016 vs. 2015 Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 139.9	$ 198.6	$ (58.7)
Investing activities	(17.2)	(160.2)	143.0
Financing activities	(140.7)	(22.8)	(117.9)
Net increase (decrease) in cash and cash equivalents	(18.0)	15.6	(33.6)
Cash and cash equivalents at beginning of year	18.0	—	18.0
Cash and cash equivalents at end of period	$ —	$ 15.6	$ (15.6)

Changes in our working capital accounts are shown in the following table and discussed below:

	For the nine months ended September 30, 2016	2015	Variance 2016 vs. 2015
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 8.4	$ 13.9	$ (5.5)
Due from General Partner and affiliates	51.5	38.7	12.8
Accrued receivables	25.1	200.6	(175.5)
Inventory	(31.5)	(9.8)	(21.7)
Current and long-term other assets	(10.8)	1.8	(12.6)
Due to General Partner and affiliates	33.8	13.3	20.5
Accounts payable and other	(25.0)	(20.6)	(4.4)
Accrued purchases	(7.5)	(177.2)	169.7
Interest payable	(3.7)	(3.8)	0.1
Property and other taxes payable	7.0	5.4	1.6
Net change in working capital accounts	$ 47.3	$ 62.3	$ (15.0)

Operating Activities

Net cash provided by our operating activities decreased $58.7 million for the nine months ended September 30, 2016, as compared to the same period in 2015, primarily due to decreased cash inflows from (1) net income after non-cash adjustments of $43.7 million, and (2) net changes in operating assets and liabilities of $15.0 million. The decreased cash flow from net income after non-cash adjustments is primarily due to reduced volumes on our systems, as described in the *Results of Operations — by Segment* discussion. The decreased cash flow from net changes in operating assets and liabilities is primarily the result of general timing differences for cash receipts and payments, and includes the following:

- Cash flow from changes in inventory decreased $21.7 million during the nine months ended September 30, 2016, as compared to the same period in 2015, primarily due to larger purchases of inventory.
- Cash flow from net changes in accrued receivables and payables decreased $5.8 million during the nine months ended September 30, 2016, as compared to the same period in 2015, primarily resulting from lower commodity prices and volumes during the nine months ended September 30, 2015, where the changes during the same period in 2016 were relatively flat.

Investing Activities

Net cash used in our investing activities during the nine months ended September 30, 2016, decreased by $143.0 million, compared to the same period in 2015, primarily due to decreased spending on acquisitions and capital projects.

Financing Activities

Net cash used in our financing activities increased $117.9 million for the nine months ended September 30, 2016, compared to the same period in 2015, primarily due to (1) net repayments under the Credit Agreement of $40.0 million for the nine months ended September 30, 2016, as compared to net borrowings of $60.0 million under the Credit Agreement for the same period in 2015; and (2) a decrease in cash provided by contributions from noncontrolling interest of $30.0 million due to a reduction in cash requirements for capital projects at Midcoast Operating.

SUBSEQUENT EVENTS

Distribution to Partners

On October 27, 2016, the board of directors of Midcoast Holdings, our General Partner, declared a cash distribution payable to our unitholders on November 14, 2016. The distribution will be paid to unitholders of record as of November 7, 2016, of our available cash of $16.5 million at September 30, 2016, or $0.3575 per limited partner unit. We will pay $7.6 million to our public Class A common unitholders, while $8.9 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, with respect to its general partner interest.

Midcoast Operating Distribution

On October 27, 2016, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable on November 14, 2016 to its partners of record as of November 7, 2016. Midcoast Operating will pay $26.0 million to us and $14.4 million to EEP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed on February 17, 2016, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. Our exposure to commodity price risk exists within our Gathering, Processing and Transportation and Logistics and Marketing segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices as well as to reduce volatility to our cash flows. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2016 and December 31, 2015:

	At September 30, 2016						At December 31, 2015	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 2.86	$ 3.48	$—	$ —	$ —	$ —
	NGL	2,694,200	$26.38	$24.49	$5.7	$(0.6)	$ 0.2	$ (8.4)
	Crude Oil	169,400	$48.75	$62.50	$0.5	$(2.8)	$ —	$(17.5)
Receive fixed/pay variable	NGL	5,040,200	$23.97	$24.96	$3.2	$(8.2)	$18.3	$ (0.2)
	Crude Oil	232,400	$60.00	$48.64	$3.0	$(0.4)	$18.2	$ —
Receive variable/pay variable	Natural Gas	5,708,000	$ 3.05	$ 3.01	$0.3	$(0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,127,893	$25.14	$23.43	$2.0	$(0.1)	$ —	$ (0.2)
	Crude Oil	—	$ —	$ —	$—	$ —	$ —	$ (0.2)
Receive fixed/pay variable	NGL	1,359,447	$21.30	$23.31	$0.8	$(3.6)	$ 1.9	$ (0.2)
Receive variable/pay variable	Natural Gas	19,810,834	$ 2.83	$ 2.84	$0.1	$(0.3)	$ —	$ (2.8)
	NGL	3,794,987	$23.37	$23.07	$1.7	$(0.5)	$ 4.0	$ (2.4)
	Crude Oil	383,298	$44.16	$47.84	$0.3	$(1.8)	$ 0.7	$ (0.5)
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	989,030	$ 2.89	$ 2.91	$—	$ —	$ —	$ —
	NGL	2,417,500	$22.03	$21.62	$2.7	$(1.7)	$ —	$ (4.5)
	Crude Oil	638,750	$51.66	$64.29	$0.2	$(8.2)	$ —	$(10.9)
Receive fixed/pay variable	NGL	3,090,000	$22.70	$23.70	$1.2	$(4.3)	$ 3.3	$ (0.1)
	Crude Oil	638,750	$63.63	$51.66	$8.2	$(0.6)	$10.9	$ —
Receive variable/pay variable	Natural Gas	12,550,000	$ 3.12	$ 3.03	$1.1	$(0.1)	$ 0.5	$ (0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	45,000	$23.42	$21.96	$0.1	$ —	$ —	$ —
Receive fixed/pay variable	NGL	45,781	$25.46	$25.39	$0.1	$(0.1)	$ —	$ —
Receive variable/pay variable	Natural Gas	11,843,834	$ 3.08	$ 3.06	$0.2	$ —	$ 0.1	$ —
	NGL	1,262,231	$26.68	$25.59	$1.4	$ —	$ —	$ —
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,193,804	$ 2.93	$ 2.90	$0.1	$ —	$ 0.1	$ —
	NGL	456,250	$23.15	$21.26	$0.8	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,199,798	$ 2.86	$ 2.83	$0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	365,634	$ 3.11	$ 3.08	$—	$ —	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGLs and crude oil are measured in Bbl.

(2) Weighted-average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGLs and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2016, and December 31, 2015, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains of approximately $0.1 million and $0.6 million at September 30, 2016 and December 31, 2015, respectively, as well as cash collateral received.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2016 and December 31, 2015:

	At September 30, 2016						At December 31, 2015	
					Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Strike Price(2)	Market Price(2)	Asset	Liability	Asset	Liability
					(in millions)			
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	414,000	$ 3.75	$ 3.00	$0.3	$ —	$ 2.1	$ —
	NGL	745,200	$39.29	$27.70	$9.2	$ —	$54.4	$ —
	Crude Oil	202,400	$75.91	$49.00	$5.4	$ —	$27.7	$ —
Calls (written)	Natural Gas	414,000	$ 4.98	$ 3.00	$—	$ —	$ —	$ —
	NGL	745,200	$45.09	$27.70	$—	$(0.3)	$ —	$(0.3)
	Crude Oil	202,400	$86.68	$49.00	$—	$ —	$ —	$ —
Puts (written)	Natural Gas	414,000	$ 3.75	$ 3.00	$—	$(0.3)	$ —	$(2.1)
	NGL	59,800	$37.04	$28.98	$—	$(0.6)	$ —	$(1.5)
Calls (purchased)	Natural Gas	414,000	$ 4.98	$ 3.00	$—	$ —	$ —	$ —
	NGL	59,800	$42.09	$28.98	$—	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,642,500	$25.90	$29.51	$5.5	$ —	$ 5.8	$ —
	Crude Oil	638,750	$59.86	$51.66	$7.6	$ —	$10.0	$ —
Calls (written)	NGL	1,642,500	$30.06	$29.51	$—	$(8.0)	$ —	$(0.8)
	Crude Oil	638,750	$68.19	$51.66	$—	$(1.2)	$ —	$(0.6)
Portion of option contracts maturing in 2018								
Puts (purchased)	Crude Oil	91,250	$42.00	$53.58	$0.3	$ —	$ —	$ —
Calls (written)	Crude Oil	91,250	$51.75	$53.58	$—	$(0.8)	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGLs and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGLs and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2016, and December 31, 2015, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment losses of approximately $0.4 million at December 31, 2015 as well as cash collateral received.

Our credit exposure for OTC derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations. The table below summarizes our derivatives balances by counterparty credit quality (any negative amounts represent our net obligations to pay the counterparty).

	September 30, 2016	December 31, 2015
	(in millions)	
Counterparty Credit Quality(1)		
AA(2)	$18.7	$67.6
A	(0.9)	24.1
Lower than A	(0.2)	0.8
	$17.6	$92.5

(1) As determined by nationally-recognized statistical ratings organizations.

(2) Includes $12.6 million of cash collateral at December 31, 2015.

Item 4. Controls and Procedures

We, EEP and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2016. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three months ended September 30, 2016.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, Note 12. *Commitments and Contingencies*, which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to our risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed with the SEC on February 17, 2016.

Item 6. Exhibits

Reference is made to the ‘‘Index of Exhibits’’ following the signature page, which we hereby incorporate into this Item.

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.

MIDCOAST ENERGY PARTNERS, L.P.
(Registrant)

By: Midcoast Holdings, L.L.C.
as General Partner

Date: October 31, 2016

By: /s/ C. Gregory Harper
C. Gregory Harper
President
(Principal Executive Officer)

Date: October 31, 2016

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as a part of this Quarterly Report on Form 10-Q. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibit Number	Description
10.1*	Amendment No. 3 to Credit Agreement, dated September 30, 2016 by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the subsidiary guarantors party thereto, the lenders party thereto and Bank of America, N.A., as administrative agent.
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, C. Gregory Harper, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Midcoast Energy Partners, L.P.;

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

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

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

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

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

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

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

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

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

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

Date: October 31, 2016

By: /s/ C. Gregory Harper

C. Gregory Harper
President
(Principal Executive Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Midcoast Energy Partners, L.P.;

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

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

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

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

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

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

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

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

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

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

Date: October 31, 2016

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

The undersigned, being the Principal Executive Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2016 (the ''Quarterly Report'') filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: October 31, 2016

By: /s/ C. Gregory Harper
C. Gregory Harper
President
(Principal Executive Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

The undersigned, being the Principal Financial Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2016 (the ''Quarterly Report'') filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: October 31, 2016

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)