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, 2015

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 30, 2015.

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, 2015, we owned a 51.6% controlling interest in Midcoast Operating, and EEP owned a 48.4% noncontrolling interest 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, 2015.

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "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 whom we sell *products; (5) hazards and operating risks that may not be covered fully by insurance; (6) changes in or challenges to our rates; and (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; and (8) cost overruns and delays on construction projects resulting from numerous factors.*

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, 2014, which is available to the public over the Internet at the United States 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,	
	2015	2014	2015	2014
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Operating revenue (Note 14)	$649.0	$1,348.8	$2,252.3	$4,268.4
Operating revenue – affiliate (Notes 12 and 14)	12.0	50.6	62.3	174.7
	661.0	1,399.4	2,314.6	4,443.1
Operating expenses:				
Cost of natural gas and natural gas liquids (Notes 6 and 14)	503.3	1,208.5	1,912.0	3,888.4
Cost of natural gas and natural gas liquids – affiliate (Notes 12 and 14)	19.4	29.7	60.4	98.3
Operating and maintenance (Notes 7 and 13)	48.8	54.3	131.7	165.5
Operating and maintenance – affiliate (Note 12)	25.2	26.3	75.2	81.0
General and administrative	1.6	2.5	4.6	6.0
General and administrative – affiliate (Note 12)	19.6	23.4	56.5	68.7
Goodwill impairment (Note 8)	—	—	226.5	—
Asset impairment (Note 7)	—	—	12.3	—
Depreciation and amortization (Note 7)	39.2	39.5	118.3	113.3
	657.1	1,384.2	2,597.5	4,421.2
Operating income (loss)	3.9	15.2	(282.9)	21.9
Interest expense, net (Notes 10 and 12)	(7.6)	(3.6)	(21.5)	(9.7)
Equity in earnings of joint ventures (Note 9)	8.9	6.1	20.5	7.1
Other loss	(0.4)	(0.8)	(0.2)	(0.7)
Income (loss) before income tax expense	4.8	16.9	(284.1)	18.6
Income tax expense (Note 15)	(3.7)	(0.9)	(1.4)	(2.7)
Net income (loss)	1.1	16.0	(285.5)	15.9
Less: Net income (loss) attributable to noncontrolling interest	4.7	9.7	(125.4)	13.8
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ (3.6)	$ 6.3	$ (160.1)	$ 2.1
Net income (loss) attributable to limited partner ownership interest	$ (3.5)	$ 6.2	$ (156.8)	$ 2.1
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	$ (0.08)	$ 0.14	$ (3.47)	$ 0.05
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,	
	2015	2014	2015	2014
	(unaudited; in millions)			
Net income (loss)	$ 1.1	$16.0	$(285.5)	$15.9
Other comprehensive income (loss), net of tax (Note 14)	(5.2)	10.2	(16.1)	8.6
Comprehensive income (loss)	(4.1)	26.2	(301.6)	24.5
Less:				
Net income (loss) attributable to noncontrolling interest	4.7	9.7	(125.4)	13.8
Other comprehensive income (loss) attributed to noncontrolling interest (Note 12)	(2.5)	6.3	(7.8)	5.3
Comprehensive income (loss) attributable to general and limited partner (Note 12) ownership interests in Midcoast Energy Partners, L.P.	$(6.3)	$10.2	$(168.4)	$ 5.4

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, 2015	For the nine months ended September 30, 2014
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income (loss)	$(285.5)	$ 15.9
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization (Note 7)	118.3	113.3
Goodwill impairment (Note 8)	226.5	—
Derivative fair value net (gains) losses (Note 14)	53.5	(11.5)
Inventory market price adjustments (Note 6)	5.4	4.8
Asset impairment (Note 7)	12.3	—
Distributions from investment in joint ventures	20.5	6.1
Equity earnings from investment in joint ventures (Note 9)	(20.5)	(7.1)
Deferred income taxes (Note 15)	0.2	1.4
Loss on sales of assets	3.2	—
Other	2.4	0.6
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	13.9	11.5
Due from General Partner and affiliates	38.7	641.7
Accrued receivables	200.6	28.0
Inventory (Note 6)	(9.8)	(129.1)
Current and long-term other assets (Note 14)	1.8	(11.5)
Due to General Partner and affiliates	13.3	(487.4)
Accounts payable and other (Notes 5 and 14)	(20.6)	(50.6)
Environmental liabilities (Note 13)	—	0.2
Accrued purchases	(177.2)	(21.3)
Interest payable	(3.8)	0.4
Property and other taxes payable	5.4	6.6
Net cash provided by operating activities	198.6	112.0
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 7 and 17)	(155.4)	(166.6)
Changes in restricted cash (Note 12)	32.1	55.6
Acquisitions (Note 3)	(43.9)	—
Proceeds from sales of assets	2.1	—
Investment in joint ventures (Note 9)	(3.0)	(35.4)
Distributions from investment in joint ventures in excess of cumulative earnings	9.5	27.0
Other	(1.6)	(0.8)
Net cash used in investing activities	(160.2)	(120.2)
Cash (used in) provided by financing activities:		
Proceeds from long-term debt, net of discounts (Note 10)	—	398.1
Net borrowings under credit facility (Note 10)	60.0	30.0
Distributions to partners (Note 11)	(48.1)	(37.1)
Acquisition of noncontrolling interest in subsidiary (Note 11)	—	(350.0)
Contributions from noncontrolling interest (Note 11)	37.3	111.8
Distributions to noncontrolling interest (Note 11)	(72.0)	(83.3)
Net cash (used in) provided by financing activities	(22.8)	69.5
Net increase in cash and cash equivalents	15.6	61.3
Cash and cash equivalents at beginning of year	—	4.9
Cash and cash equivalents at end of period	$ 15.6	$ 66.2

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

MIDCOAST ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2015	December 31, 2014
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 5)	$ 15.6	$ —
Restricted cash (Notes 3, 12 and 14)	25.7	42.8
Receivables, trade and other, net of allowance for doubtful accounts of $1.6 million and $1.8 million, respectively, at September 30, 2015 and December 31, 2014	1.5	15.6
Due from General Partner and affiliates (Note 12)	17.9	49.7
Accrued receivables	29.0	229.6
Inventory (Note 6)	85.9	81.5
Other current assets (Notes 7 and 14)	136.9	178.1
	312.5	597.3
Property, plant and equipment, net (Note 7)	4,222.7	4,159.7
Goodwill (Note 8)	—	226.5
Intangible assets, net	277.2	247.7
Equity investment in joint ventures (Note 9)	373.7	380.6
Other assets, net (Note 14)	106.7	142.3
Total assets	$5,292.8	$5,754.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 12)	$ 35.6	$ 41.1
Accounts payable and other (Notes 5, 13 and 14)	89.8	113.8
Accrued purchases	198.0	375.2
Property and other taxes payable (Note 15)	26.3	20.9
Interest payable	1.2	5.0
	350.9	556.0
Long-term debt (Note 10)	820.0	760.0
Other long-term liabilities (Notes 13 and 15)	49.8	41.5
Total liabilities	1,220.7	1,357.5
Commitments and contingencies (Note 13)		
Partners' capital (Note 11):		
Class A common units (22,610,056 authorized and issued at September 30, 2015 and December 31, 2014)	532.2	634.2
Subordinated units (22,610,056 authorized and issued at September 30, 2015 and December 31, 2014)	1,072.0	1,174.0
General Partner units (922,859 authorized and issued at September 30, 2015 and December 31, 2014)	43.6	47.8
Accumulated other comprehensive income (Note 14)	3.3	11.6
Total Midcoast Energy Partners, L.P. partners' capital	1,651.1	1,867.6
Noncontrolling interest	2,421.0	2,529.0
Total partners' capital	4,072.1	4,396.6
	$5,292.8	$5,754.1

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.'' For the first six months of 2014, we owned a 39% controlling interest in Midcoast Operating, L.P., or Midcoast Operating. EEP owned the remaining 61% interest in Midcoast Operating. On July 1, 2014, we purchased an additional 12.6% interest in Midcoast Operating from EEP. We own and operate, through our current 51.6% controlling interest in 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, 2015, our results of operations for the three and nine months ended September 30, 2015 and 2014, and our cash flows for the nine months ended September 30, 2015 and 2014. We derived our consolidated statement of financial position as of December 31, 2014, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014. Our results of operations for the three and nine months ended September 30, 2015 and 2014, 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, 2014.

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 to our limited partners, our General Partner and the holders of our IDRs in accordance with the terms of our partnership agreement. We also allocate any earnings in excess of distributions to our limited partners, our General Partner and the holders of the 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.

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

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%

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(in millions, except per unit amounts)			
Net income (loss)	$ 1.1	$ 16.0	$(285.5)	$ 15.9
Less: Net income (loss) attributable to noncontrolling interest	4.7	9.7	(125.4)	13.8
Net income (loss) attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	(3.6)	6.3	(160.1)	2.1
Less 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)	(15.3)	(47.9)	(44.1)
Total distributed earnings	(16.5)	(15.6)	(48.8)	(45.0)
Overdistributed earnings	$(20.1)	$ (9.3)	$(208.9)	$(42.9)
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	$ 0.34	$ 1.06	$ 0.98
Overdistributed earnings per limited partner unit(2)	(0.44)	(0.20)	(4.53)	(0.93)
Net income (loss) per limited partner unit (basic and diluted)	$(0.08)	$ 0.14	$ (3.47)	$ 0.05

(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 AND DISPOSITIONS

Acquisitions

We account for acquisitions using the acquisition method and record the identifiable assets acquired and liabilities assumed at their acquisition-date fair values. We have included the results of operations in our operating results from the acquisition date.

On February 27, 2015, we acquired the midstream business of New Gulf Resources, LLC, or NGR, in Leon, Madison and Grimes counties, Texas. The acquisition consisted of a natural gas gathering system that is in operation. This acquisition strengthened our position into the Eaglebine play, and will continue to allow us to offer gathering and processing services while leveraging assets on our existing footprint.

We acquired the midstream business of NGR 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 NGR's completion of additional wells connecting to our system. Since the acquisition date, we have released $5.0 million from escrow and paid it to NGR. The remaining $15.0 million in escrow has been classified as ''Restricted cash'' in our consolidated statements of financial position as of September 30, 2015.

If NGR is able to deliver volumes into the system at certain tiered volume levels over a five-year period, we will be obligated to make future tiered payments up to $17.0 million. This could result in a maximum total purchase

3. ACQUISITIONS AND DISPOSITIONS – (continued)

price of $102.0 million. The potential payment is considered 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 is remeasured on a fair value basis each quarter until the performance bonus is paid or expires. At September 30, 2015, contingent consideration of $2.5 million, which includes $0.2 million in accretion, is included in ''Other long-term liabilities'' in our consolidated statement of financial position.

Funding was provided by us and EEP, based on our proportionate ownership percentages in Midcoast Operating, at the time of acquisition, which was 51.6% and 48.4%, respectively. EEP paid its portion of the funding directly to NGR. Our consolidated statements of cash flows do not reflect the amount paid directly to NGR by EEP.

As of September 30, 2015, the consideration paid and the purchase price allocation related to the NGR acquisition, as adjusted to date, are as follows:

	September 30, 2015
	(in millions)
Consideration:	
Cash consideration	$85.0
Contingent consideration	2.3
	$87.3
Identifiable assets acquired in business combination:	
Property, plant and equipment	$55.1
Intangible assets	32.2
	$87.3

The weighted-average amortization period of intangible assets related to the NGR acquisition is 15 years. Our consolidated operating revenue and net income included from NGR, $0.6 million and $0.1 million, respectively, for the three months ended September 30, 2015, and $1.2 million and $0.2 million, respectively, for the nine months ended September 30, 2015.

Since the effective date of the NGR midstream business acquisition was February 27, 2015, our consolidated statements of income do not include earnings from this business prior to that date. The following table presents selected unaudited pro forma earnings information for the three and nine months ended September 30, 2015 and 2014, as if the acquisition had been completed on January 1, 2014. This pro forma information was prepared using historical financial data for the NGR midstream business and reflects certain estimates and assumptions made by our management based on currently available information. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been for the three and nine months ended September 30, 2015 and 2014, had we acquired the NGR midstream business on January 1, 2014.

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(unaudited; in millions, except per unit amounts)			
Pro forma earnings data:				
Operating revenue	$661.0	$1,399.6	$2,314.7	$4,443.8
Operating expenses	$657.1	$1,384.4	$2,597.9	$4,422.5
Operating income (loss)	$ 3.9	$ 15.2	$ (283.2)	$ 21.3
Net income (loss)	$ 1.1	$ 16.0	$ (285.8)	$ 15.3
Net income (loss) attributable to noncontrolling interest	$ 4.7	$ 9.7	$ (125.5)	$ 13.5
Net income (loss) attributable to limited partner ownership interest	$ (3.6)	$ 6.3	$ (160.3)	$ 1.8
Basic and diluted earnings per unit:				
As reported net income (loss) per limited partner unit (basic and diluted)	$ (0.08)	$ 0.14	$ (3.47)	$ 0.05
Pro forma net income (loss) per limited partner unit (basic and diluted)	$ (0.08)	$ 0.14	$ (3.46)	$ 0.04

3. ACQUISITIONS AND DISPOSITIONS – (continued)

Dispositions

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 buyer. Midcoast Operating subsidiaries will now sell their natural gas products directly to third parties, instead of through the Logistics and Marketing segment.

We received net proceeds of $4.3 million and recognized a loss of $9.3 million included in our ''Segment gross margin,'' which includes losses to transfer certain fixed-demand storage and transportation obligations to the buyer. The proceeds included a prepayment of $4.2 million, which represents compensation for us to deliver natural gas to the buyer over the next 14 months. This amount has been deferred in ''Accounts payable and other'' on our consolidated statement of financial position, and will be recognized in operating revenue over the term of the contract. In addition, we recognized $1.3 million in severance costs associated with the transaction, which is included in ''Operating and maintenance'' expense on our consolidated statement of income.

4. EQUITY-BASED COMPENSATION

In November 2013, our General Partner adopted the 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or the LTIP. The LTIP provides for the grant of, from time to time at the discretion of the board of directors of our General Partner or any delegate thereof, subject to applicable law, unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards, provided that while we are an affiliate of Enbridge, awards will only be granted following a recommendation of the board of directors or compensation committee of Enbridge to the board of our General Partner. The purpose of awards under the LTIP is to provide additional incentive compensation to individuals providing services to us, and to align the economic interests of such individuals with the interests of our unitholders.

On February 17, 2015, the board of our General Partner approved the first grant of Performance Stock Units, or PSUs, effective January 1, 2015, under the LTIP. These PSUs were granted to employees of affiliates of our General Partner performing services on our behalf and provide for cash awards to be paid at the end of the three-year term, at which time the PSUs will vest 100%. Awards are calculated by multiplying the number of PSUs outstanding at the end of the performance period by the weighted-average price of our Class A common units for the 20-trading days prior to the maturity of the PSUs and by a performance multiplier. Any cash distributions paid will be notionally reinvested during the term of the PSUs.

The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of two if we perform within the highest range of its performance targets. The 2015 PSUs derive the performance multiplier through a calculation of our distributable cash flow per unit relative to targets established at the time of grant and yield relative to a specified peer group of companies.

4. EQUITY-BASED COMPENSATION – (continued)

The following table presents PSU activity for the period indicated:

	Performance Stock Units	Weighted Average Remaining Term (years)	Average Intrinsic Value (in millions)
January 1, 2015	—		
Units granted	323,880		
Units matured	—		
Units forfeited	(1,948)		
Distribution reinvested	27,384		
September 30, 2015	349,316	2.3	$3.6

The PSUs are paid in cash and therefore classified as a liability award. The liability is re-measured at fair value on each reporting date until the award is settled, with the offset for the change in fair value being recorded as compensation expense based on the percentage of the requisite service that has been rendered at the reporting date. During the vesting term, compensation expense is determined based on the number of PSUs outstanding, the current market price of our Class A common units, dividends reinvested, and performance multipliers. The LTIP agreement and the individual award agreements are between our General Partner and the participants in the LTIP agreement. The associated compensation costs and liability are recorded in our consolidated financial statements based on the approved allocation methodology as some of the recipients of our PSUs provide shared services to us, EEP and other Enbridge entities. Similar to other employee compensation costs, Enbridge Employee Services Incorporated, or EESI, will make the PSU payments to the LTIP participants on behalf of us, EEP and other Enbridge entities who will then reimburse EESI, for their respective obligation, via an affiliate payable for the disbursements made to the participants.

To calculate the compensation expense for the three and nine months ended September 30, 2015, a performance multiplier of one, based on estimates as of September 30, 2015, was used for the 2015 PSUs. For the three and nine months ended September 30, 2015, compensation expense recorded for the PSUs was $0.3 million and $0.9 million, respectively, of which our allocated share of the cost is currently estimated to be $0.1 million and $0.3 million, respectively. As of September 30, 2015, the unrecognized compensation expense related to non-vested units granted was $3.8 million and is expected to be fully recognized over a weighted-average period of approximately two years.

5. 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 $4.7 million at September 30, 2015, and $6.6 million at December 31, 2014, are included in ‘‘Accounts payable and other’’ on our consolidated statements of financial position.

6. INVENTORY

Our inventory is comprised of the following:

	September 30, 2015	December 31, 2014
	(in millions)	
Materials and supplies	$ 0.6	$ 0.7
Crude oil inventory	—	2.0
Natural gas and NGL inventory	85.3	78.8
	$85.9	$81.5

6. INVENTORY – (continued)

The ''Cost of natural gas and natural gas liquids'' on our consolidated statements of income includes charges totaling $0.1 million and $1.5 million for the three months ended September 30, 2015, and 2014 respectively, and $5.4 million and $4.8 million for the nine months ended September 30, 2015, and 2014 respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs, to reflect the current market value.

7. PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2015	December 31, 2014
	(in millions)	
Land	$ 14.2	$ 11.1
Rights-of-way	436.2	405.0
Pipelines	1,848.3	1,785.7
Pumping equipment, buildings and tanks	88.4	82.1
Compressors, meters and other operating equipment	2,145.6	2,074.8
Vehicles, office furniture and equipment	137.5	163.8
Processing and treating plants	632.8	516.0
Construction in progress	74.4	218.7
Total property, plant and equipment	5,377.4	5,257.2
Accumulated depreciation	(1,154.7)	(1,097.5)
Property, plant and equipment, net	$ 4,222.7	$ 4,159.7

On July 31, 2015, we sold our non-core Tinsley crude oil pipeline, storage facilities, and docks in our Logistics and Marketing segment and our non-core Louisiana propylene pipeline in our Gathering, Processing and Transportation segment. The sale price was $1.3 million, and the assets had a combined carrying amount of $4.5 million. The loss on disposal of $3.2 million for the three and nine months ended September 30, 2015, 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 2015, we recorded $12.3 million in non-cash impairment charges on these assets, which are included in ''Asset impairment'' on our consolidated statements of income.

8. GOODWILL

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. Our goodwill originated from acquisitions by EEP that are fully associated with our gathering, processing and transportation and logistics and marketing businesses. As of December 31, 2014, the carrying amount of goodwill was $226.5 million, consisting of $206.1 million and $20.4 million related to our gathering, processing and transportation and marketing reporting units, respectively.

We test goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. During May 2015, due to adverse market conditions facing our business, we learned from producers that reductions in drilling will be sustained and prolonged due to continued low prices for natural gas and NGLs. As a result, we determined that the impact on our forecasted operating profits and cash flows for both the gathering, processing and transportation and marketing reporting units for the next five years would be significantly reduced from our prior forecasts.

During the second quarter of 2015, we performed the first step of our goodwill impairment analysis and determined that the carrying value of the gathering, processing and transportation and marketing reporting units exceeded fair value. We completed the second step of the goodwill impairment analysis comparing the implied fair value of the reporting units to the carrying amounts of that goodwill and determined that goodwill was completely impaired, including $206.1 million for the Gathering, Processing and Transportation segment and $20.4 million for

8. GOODWILL – (continued)

the Logistics and Marketing segment. The total impairment charge of $226.5 million is presented as ''Goodwill impairment'' on our consolidated statement of income for the nine months ended September 30, 2015.

We measure the fair value of our reporting units primarily by using a discounted cash flow analysis. In addition, we also consider overall market capitalization of our business, cash flow measurement data and other factors. Our estimate of fair value required us to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of our gathering, processing and transportation and marketing reporting units.

9. 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 the Texas Express NGL system is presented in ''Equity investment in joint ventures'' on our consolidated statements of financial position. ''Equity in earnings of joint ventures'' on our consolidated statements of income represents our earnings related to these joint ventures. 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,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues	$36.5	$27.3	$93.9	$51.7
Operating expenses	$11.1	$ 9.7	$33.8	$30.0
Net income	$25.4	$17.5	$59.9	$21.6

10. DEBT

The following table presents the carrying amounts, net of related unamortized discounts, of our consolidated debt obligations.

	Interest Rate	September 30, 2015	December 31, 2014
		(in millions)	
Credit Agreement due 2016 – 2018	2.672%	$420.0	$360.0
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		$820.0	$760.0

Our interest cost for the three and nine months ended September 30, 2015, and 2014, is comprised of the following:

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Interest cost incurred	$7.8	$4.0	$23.0	$10.3
Less: Interest capitalized	0.2	0.4	1.5	0.6
Interest expense, net	$7.6	$3.6	$21.5	$ 9.7

10. DEBT – (continued)

Debt Arrangements

Credit Agreement

We, Midcoast Operating, and our material domestic subsidiaries are parties to the Credit Agreement, which previously permitted aggregate borrowings of up to, at any one time outstanding, $850.0 million. On September 3, 2015 we amended our Credit Agreement and decreased the aggregate commitments to $810.0 million. 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 extensions. On September 3, 2015, we further amended our Credit Agreement to extend the maturity date from September 30, 2017 to 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, 2015, we had $420.0 million in outstanding borrowings under the Credit Agreement at a weighted-average interest rate of 2.67%. Under the Credit Agreement, we had net borrowings of approximately $60.0 million during the nine months ended September 30, 2015, which includes gross borrowings of $4,160.0 million and gross repayments of $4,100.0 million. At September 30, 2015, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Senior Notes

Our senior notes in the aggregate amount of $400.0 million were issued in a private placement on September 30, 2014 and consist of three tranches: $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, which commenced on March 31, 2015. At September 30, 2015, we were in compliance with the terms of our financial covenants under the note purchase agreement.

Financial Support Agreement

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.

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 and $0.4 million of these costs for the three and nine months ended September 30, 2015, respectively, which is included in ''Operating and maintenance-affiliate'' on our consolidated statements of income.

Available Credit

At September 30, 2015, we had approximately $390.0 million of unutilized commitments under the terms of our Credit Agreement, determined as follows:

	(in millions)
Total credit limit under Credit Agreement	$ 810.0
Amounts outstanding under Credit Agreement	(420.0)
Total amount available at September 30, 2015	$ 390.0

10. DEBT – (continued)

Fair Value of Debt Obligations

The carrying amount of our outstanding borrowings under the Credit Agreement approximates the fair value at September 30, 2015 and December 31, 2014, 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 $393.0 million at September 30, 2015. 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.

11. 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, 2015.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
			(in millions, except per unit amounts)	
July 29, 2015	August 7, 2015	August 14, 2015	$0.35250	$16.3
April 29, 2015	May 8, 2015	May 15, 2015	$0.34750	$16.0
January 28, 2015	February 6, 2015	February 13, 2015	$0.34250	$15.8

We paid cash distributions to EEP for its ownership interest in us totaling $8.8 million and $8.1 million for the three months ended September 30, 2015 and 2014, respectively, and $25.9 million and $20.0 million for the nine months ended September 30, 2015 and 2014, respectively. These amounts are reflected in ''Distributions to partners,'' on our consolidated statements of cash flows.

Distributions to Noncontrolling Interests

Midcoast Operating paid cash distributions to EEP for its ownership interest in Midcoast Operating totaling $26.2 million and $22.1 million for the three months ended September 30, 2015 and 2014, respectively, and $72.0 million and $83.3 million for the nine months ended September 30, 2015 and 2014, respectively. These amounts are reflected in ''Distributions to noncontrolling interest'' in our consolidated statements of cash flows.

On July 29, 2015, the partners of Midcoast Operating approved an amendment to Midcoast Operating's limited partnership agreement that would potentially enhance our distributable cash flow, demonstrating EEP's further support of our ongoing cash distribution strategy and growth outlook. The amendment will provide a mechanism for us to receive increased quarterly distributions from Midcoast Operating and for EEP to receive reduced quarterly distributions if our declared distribution exceeds our distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement. 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 requirement for us to compensate EEP for these adjusted distributions, except for settling our capital accounts with Midcoast Operating in a liquidation scenario. The amendment to the limited partnership agreement and the support it provides to our cash distribution is effective with the quarter ended June 30, 2015, and continues through and including the distribution made for the quarter ending December 31, 2017. In 2015, we have not received an increased allocation of cash distributions from Midcoast Operating as distributable cash flow we generated exceeded the cash distribution amount we declared for payout.

11. PARTNERS' CAPITAL – (continued)

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, 2015 and 2014.

	For the nine months ended September 30,	
	2015	2014
	(in millions)	
Class A common units:		
Beginning balance	$ 634.2	$ 495.3
Net income (loss)	(78.4)	1.0
Acquisition of noncontrolling interest in subsidiary	—	133.3
Distributions	(23.6)	(18.2)
Ending balance	$ 532.2	$ 611.4
Subordinated units:		
Beginning balance	$1,174.0	$1,035.1
Net income (loss)	(78.4)	1.1
Acquisition of noncontrolling interest in subsidiary	—	133.3
Distributions	(23.6)	(18.2)
Ending balance	$1,072.0	$1,151.3
General Partner units:		
Beginning balance	$ 47.8	$ 42.2
Net loss	(3.3)	—
Acquisition of noncontrolling interest in subsidiary	—	5.4
Distributions	(0.9)	(0.7)
Ending balance	$ 43.6	$ 46.9
Accumulated other comprehensive income (loss)		
Beginning balance	$ 11.6	$ (3.1)
Changes in fair value of derivative financial instruments reclassified to earnings	(12.5)	5.1
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	4.2	(1.8)
Ending balance	$ 3.3	$ 0.2
Noncontrolling interest		
Beginning balance	$2,529.0	$2,983.2
Capital contributions	97.2	130.5
Acquisition of noncontrolling interest in subsidiary	—	(622.0)
Comprehensive income:		
Net income (loss)	(125.4)	13.8
Other comprehensive income (loss), net of tax	(7.8)	5.3
Distributions to noncontrolling interest	(72.0)	(83.3)
Ending balance	$2,421.0	$2,427.5
Total partners' capital at end of period	$4,072.1	$4,237.3

11. PARTNERS' CAPITAL – (continued)

Securities Authorized for Issuance under LTIP

In connection with our LTIP, 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 LTIP. As of September 30, 2015, we have not granted any awards for Class A common units under our LTIP.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the offer and sale of debt or equity securities in public offerings. In December 2014, we filed a shelf-registration statement on Form S-3 with the SEC, which became effective on February 5, 2015, with a proposed aggregate offering price for all securities registered of $1.5 billion.

12. RELATED PARTY TRANSACTIONS

Intercorporate Services Agreement

We do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We have an Intercorporate Services Agreement with EEP, pursuant to which EEP and its affiliates provides us with services as set forth in the agreement, which include such functions as management, accounting, operational and administrative personnel, among other such functions.

Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. The 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. 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, for the three and nine months ended September 30, 2015, we recognized $6.3 million and $18.8 million, respectively, as a reduction to ''Due to General Partner and affiliates'' with the offset recorded as a contribution to ''Noncontrolling interest'' in our consolidated statements of financial position.

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $2.2 million and $5.8 million as of September 30, 2015 and December 31, 2014, respectively, which we recorded as additions to ''Property, plant and equipment, net'' on our consolidated statements of financial position.

Affiliate Revenues and Purchases

We sell natural gas, 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 ''Operating revenue — affiliate'' on our consolidated statements of income. We also purchase natural gas, NGLs and crude oil at market prices on the date of purchase from Enbridge and its affiliates for sale to third parties. The purchases of natural gas, NGLs and crude oil 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 $5.1 million and $5.4 million for the three months ended September 30, 2015 and 2014, respectively, and $13.4 million and $16.8 million for the nine months ended September 30, 2015 and 2014, respectively, of pipeline transportation and demand fees from Texas Express NGL system. 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 from 2015 to 2022. The current commitment level is 29,000 Bpd.

Routine purchases and sales with affiliates are settled monthly through MEP's centralized treasury function at terms that are consistent with third-party transactions for the three and nine months ended September 30, 2015 and 2014. 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.

12. RELATED PARTY TRANSACTIONS – (continued)

Sale of Accounts Receivable

We sold and derecognized receivables to an indirect wholly-owned subsidiary of Enbridge for $509.8 million and $845.7 million for the three months ended September 30, 2015 and 2014, respectively, and $1,752.4 million and $2,702.2 million for the nine months ended September 30, 2015 and 2014, respectively. We received cash proceeds of $509.7 million and $845.5 million for the three months ended September 30, 2015 and 2014, respectively, and $1,751.9 million and $2,701.5 million for the nine months ended September 30, 2015 and 2014, respectively. As of September 30, 2015 and December 31, 2014, $221.0 million and $272.7 million, respectively, of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

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 $0.1 million and $0.2 million for the three months ended September 30, 2015 and 2014, respectively, and $0.5 million and $0.7 million for the nine months ended September 30, 2015 and 2014, respectively.

As of September 30, 2015 and December 31, 2014, we had $6.7 million and $17.7 million, respectively, in ''Restricted cash'' on our consolidated statements of financial position, consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary.

13. 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 the operating activities of our gathering, processing and transportation and logistics and marketing businesses, 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 the operating activities of our gathering, processing and transportation and logistics and marketing businesses. 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, 2015, we did not have any remaining material accrued environmental liabilities. As of December 31, 2014, we had $0.2 million of accrued environmental liabilities included in ''Other long-term liabilities'' on our consolidated statements of financial position.

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.

14. 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 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

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

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, 2015	December 31, 2014
	(in millions)	
Other current assets	$127.6	$164.7
Other assets, net	54.3	91.5
Accounts payable and other[1]	(58.2)	(74.4)
Other long-term liabilities	(21.8)	(22.5)
Due from General Partner and affiliates	—	0.3
	$101.9	$159.6

(1) Includes $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

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.

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

	September 30, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality[1]		
AAA	$ 0.2	$ 0.1
AA[2]	67.7	74.4
A	29.6	67.1
Lower than A	4.4	18.0
	$101.9	$159.6

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

(2) Includes $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

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. As of September 30, 2015, and December 31, 2014, our short-term liabilities included $16.2 million and $28.4 million, respectively, relating to cash collateral on our asset exposures. At September 30, 2015, our restricted cash included $4.0 million of the $16.2 million in cash collateral with the remaining $12.2 million of cash collateral held by EEP. Cash collateral is classified as ‘‘Restricted cash’’ in our consolidated statements of financial position. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

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

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.

In the event that our 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 credit ratings had been below the lowest level of investment grade at September 30, 2015, we would have been required to provide additional letters of credit in the amount of $12.2 million.

At September 30, 2015, and December 31, 2014, we had credit concentrations in the following industry sectors, as presented below:

	September 30, 2015	December 31, 2014
	(in millions)	
United States financial institutions and investment banking entities[1]	$ 81.4	$ 88.5
Non-United States financial institutions	(6.5)	30.7
Integrated oil companies	2.0	1.7
Other	25.0	38.7
	$101.9	$159.6

[1] Includes $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

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.

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

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, 2015	December 31, 2014	September 30, 2015	December 31, 2014
		(in millions)			
Derivatives designated as cash flow hedging instruments:[1]					
Commodity contracts	Other current assets	$ 7.4	$ 26.1	$ —	$ —
Commodity contracts	Other assets	—	2.1	—	—
		7.4	28.2	—	—
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	120.2	138.6	—	—
Commodity contracts	Other assets	54.3	89.4	—	—
Commodity contracts	Accounts payable and other[2]	—	—	(42.0)	(46.0)
Commodity contracts	Other long-term liabilities	—	—	(21.8)	(22.5)
Commodity contracts	Due from general partner and affiliates	—	0.3	—	—
		174.5	228.3	(63.8)	(68.5)
Total derivative instruments		$181.9	$256.5	$(63.8)	$(68.5)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

(2) Excludes total of $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

Accumulated Other Comprehensive Income

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. As of September 30, 2015 and December 31, 2014, we included in AOCI unrecognized gains of approximately $0.4 million and unrecognized losses of approximately $0.1 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 gains are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the nine months ended September 30, 2015 and 2014, unrealized commodity hedge gains of $1.5 million and losses of $0.2 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $8.3 million, representing unrealized net gains from our cash flow hedging activities based on pricing and positions at September 30, 2015, will be reclassified from AOCI to earnings during the next 12 months.

14. 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, 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 three months ended September 30, 2014					
Commodity contracts . . .	$ 11.2	Cost of natural gas and natural gas liquids	$ (2.1)	Cost of natural gas and natural gas liquids	$ 0.9
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)
For the nine months ended September 30, 2014					
Commodity contracts . . .	$ 7.9	Cost of natural gas and natural gas liquids	$(12.4)	Cost of natural gas and natural gas liquids	$ 1.5

(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	
	2015	2014
	(in millions)	
Balance at January 1	$ 11.6	$(3.1)
Other comprehensive income (loss) before reclassifications[1][2]	4.1	(1.8)
Amounts reclassified from AOCI[3][4]	(12.5)	5.1
Tax benefit	0.1	—
Net other comprehensive income (loss)	$ (8.3)	$ 3.3
Balance at September 30	$ 3.3	$ 0.2

(1) Excludes NCI gain of $3.7 million and NCI loss of $2.9 million reclassified from AOCI at September 30, 2015 and 2014, respectively.

(2) Excludes NCI gain of $0.9 million reclassified from AOCI related to the acquisition of additional interests in Midcoast Operating as of September 30, 2014.

(3) Excludes NCI loss of $11.5 million and NCI gain of $7.3 million reclassified from AOCI at September 30, 2015 and 2014, respectively.

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

14. 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,	
	2015	2014	2015	2014
	(in millions)			
Losses (gains) on cash flow hedges:				
Commodity Contracts[(1)(2)(3)]	$(4.5)	$1.1	$(12.5)	$5.1
Total Reclassifications from AOCI	$(4.5)	$1.1	$(12.5)	$5.1

(1) Loss (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 and NCI gain of $1.0 million reclassified from AOCI for the three months ended September 30, 2015 and 2014, respectively.

(3) Excludes NCI loss of $11.5 million and NCI gain of $7.3 million reclassified from AOCI for the nine months ended September 30, 2015 and 2014, respectively.

Effect of Derivative Instruments on Consolidated Statements of Income

		For the three months ended September 30,		For the nine months ended September 30,	
		2015	2014	2015	2014
Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	Amount of Gain or (Loss) Recognized in Earnings[(1)(2)]		Amount of Gain or (Loss) Recognized in Earnings[(1)(2)]	
		(in millions)			
Commodity contracts	Operating revenue	$ (7.2)	$ 7.7	$(22.4)	$10.8
Commodity contracts	Operating revenue – affiliate	—	(0.1)	(0.3)	0.4
Commodity contracts	Cost of natural gas and natural gas liquids[(3)]	40.7	9.5	44.3	(9.9)
Total		$33.5	$17.1	$ 21.6	$ 1.3

(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 qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

(3) Includes settlements gains (losses) of $27.3 million and $0.1 million for the three months ended September 30, 2015 and 2014, respectively, and settlement gains (losses) of $71.0 million and $(8.6) million for the nine months ended September 30, 2015 and 2014, respectively.

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.

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

Offsetting of Financial Assets and Derivative Assets

	As of September 30, 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	$181.9	$—	$181.9	$(59.9)	$122.0

	As of December 31, 2014				
	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	$256.5	$—	$256.5	$(91.8)	$164.7

[1] Includes $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of September 30, 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	$(80.0)	$—	$(80.0)	$59.9	$(20.1)

	As of December 31, 2014				
	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	$(96.9)	$—	$(96.9)	$91.8	$(5.1)

[1] Includes $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

14. 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 our net financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2015, and December 31, 2014. 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, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Commodity contracts:								
Financial	$—	$6.1	$ 14.3	$ 20.4	$—	$19.1	$ 42.7	$ 61.8
Physical	—	—	4.6	4.6	—	—	19.5	19.5
Commodity options	—	—	93.1	93.1	—	—	106.7	106.7
	$—	$6.1	$112.0	$118.1	$—	$19.1	$168.9	$188.0
Cash Collateral				(16.2)				(28.4)
Total				$101.9				$159.6

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 value our Level 3 derivative instruments, which are fair-valued 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 oil) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. 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 adjustment would change the fair value of the positions in opposite directions.

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

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at September 30, 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 Gas Price	2.41	3.16	2.84	MMBtu
NGLs	14.0	Market Approach	Forward NGL Price	0.20	0.99	0.51	Gal
Commodity Contracts – Physical							
Natural Gas	(3.9)	Market Approach	Forward Gas Price	2.33	3.53	2.61	MMBtu
Crude Oil	(0.4)	Market Approach	Forward Crude Oil Price	31.17	47.93	44.35	Bbl
NGLs	8.9	Market Approach	Forward NGL Price	0.20	1.39	0.43	Gal
Commodity Options							
Natural Gas, Crude and NGLs	93.1	Option Model	Option Volatility	10%	62%	35%	
Total Fair Value	$112.0						

(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 $0.3 million.

Contract Type	Fair Value at December 31, 2014[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 0.6	Market Approach	Forward Gas Price	2.55	3.72	3.04	MMBtu
NGLs	42.1	Market Approach	Forward NGL Price	0.48	1.14	0.64	Gal
Commodity Contracts – Physical							
Natural Gas	1.5	Market Approach	Forward Gas Price	1.55	4.08	3.08	MMBtu
Crude Oil	(0.9)	Market Approach	Forward Crude Oil Price	49.57	55.60	53.51	Bbl
NGLs	18.9	Market Approach	Forward NGL Price	0.06	1.21	0.54	Gal
Commodity Options							
Natural Gas, Crude and NGLs	106.7	Option Model	Option Volatility	19%	94%	36%	
Total Fair Value	$168.9						

(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 $1.0 million.

14. 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, 2015 to September 30, 2015. 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, 2015	$ 42.7	$ 19.5	$106.7	$ 168.9
Transfer out of Level 3[1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Operating revenue	—	(3.2)	—	(3.2)
Reported in Cost of natural gas and natural gas liquids	(1.1)	18.8	30.2	47.9
Gains or losses included in other comprehensive income:				
Reported in Other comprehensive income (loss), net of tax	0.4	—	—	0.4
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	2.0	2.0
Settlements[2]	(27.7)	(30.5)	(45.8)	(104.0)
Ending balance as of September 30, 2015	$ 14.3	$ 4.6	$ 93.1	$ 112.0
Amounts reported in Operating revenue	$ —	$(22.7)	$ —	$ (22.7)
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 Operating revenue	$ —	$ (1.4)	$ —	$ (1.4)
Reported in Cost of natural gas and natural gas liquids	$ (2.0)	$ 5.3	$ 30.6	$ 33.9

(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.

14. 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, 2015 and December 31, 2014.

	At September 30, 2015						At December 31, 2014	
			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 2015								
Swaps								
Receive variable/pay fixed	NGL	964,000	$22.66	$25.42	$ 0.7	$ (3.3)	$ —	$ (6.8)
	Crude Oil	350,000	$45.54	$72.70	$ —	$ (9.5)	$ —	$(27.4)
Receive fixed/pay variable	NGL	1,913,800	$29.66	$24.25	$11.3	$ (1.0)	$39.2	$ —
	Crude Oil	398,720	$81.28	$45.63	$14.2	$ —	$42.4	$ —
Receive variable/pay variable	Natural Gas	828,000	$ 2.45	$ 2.52	$ —	$ (0.1)	$ 1.5	$ (1.7)
Physical Contracts								
Receive variable/pay fixed	NGL	50,000	$31.63	$33.02	$ —	$ (0.1)	$ —	$ (3.6)
	Crude Oil	8,600	$45.26	$45.12	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	3,048,988	$18.83	$17.16	$ 6.4	$ (1.3)	$19.8	$ —
	Crude Oil	54,500	$42.69	$45.80	$ —	$ (0.2)	$ 0.5	$ —
Receive variable/pay variable	Natural Gas	54,524,000	$ 2.48	$ 2.49	$ —	$ (0.8)	$ 2.2	$ (1.0)
	NGL	5,150,479	$20.54	$20.07	$ 5.3	$ (2.9)	$ 3.7	$ (1.0)
	Crude Oil	742,342	$43.59	$43.90	$ 1.3	$ (1.5)	$ 0.3	$ (1.7)
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 2.72	$ 3.48	$ —	$ —	$ —	$ (0.1)
	NGL	833,500	$23.81	$30.54	$ —	$ (5.6)	$ —	$ —
	Crude Oil	415,950	$49.02	$82.69	$ —	$(14.0)	$ —	$ (8.1)
Receive fixed/pay variable	NGL	1,428,500	$31.34	$22.26	$13.3	$ (0.3)	$ 9.3	$ —
	Crude Oil	425,950	$84.17	$48.95	$14.9	$ —	$ 9.1	$ —
Receive variable/pay variable	Natural Gas	5,124,000	$ 2.79	$ 2.76	$ 0.2	$ —	$ 0.5	$ (0.3)
Physical Contracts								
Receive fixed/pay variable	NGL	233,952	$20.02	$19.25	$ 0.2	$ (0.1)	$ —	$ —
Receive variable/pay variable	Natural Gas	177,875,634	$ 2.62	$ 2.64	$ —	$ (3.4)	$ 0.7	$ (0.4)
	NGL	9,640,509	$17.02	$16.88	$ 1.6	$ (0.2)	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	76,530	$ 2.62	$ 2.97	$ —	$ —	$ —	$ —
	NGL	547,500	$19.97	$25.86	$ —	$ (3.2)	$ —	$ —
	Crude Oil	547,500	$52.74	$66.72	$ —	$ (7.6)	$ —	$ —
Receive fixed/pay variable	NGL	547,500	$23.59	$19.97	$ 2.0	$ —	$ 0.7	$ —
	Crude Oil	547,500	$66.78	$52.74	$ 7.6	$ —	$ 0.8	$ —
Receive variable/pay variable	Natural Gas	8,050,000	$ 2.82	$ 2.77	$ 0.4	$ —	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.03	$ 3.01	$ 0.1	$ —	$ 0.2	$ (0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.16	$ 3.14	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.25	$ 3.22	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.55	$ 3.52	$ —	$ —	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains (losses) of approximately $0.4 million and ($0.4) million at September 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

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

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity options at September 30, 2015 and December 31, 2014.

	At September 30, 2015						At December 31, 2014	
					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 2015								
Puts (purchased)	Natural Gas	1,012,000	$ 3.90	$ 2.60	$ 1.3	$ —	$ 3.8	$ —
	NGL	579,600	$43.32	$23.75	$11.4	$ —	$40.2	$ —
	Crude Oil	184,000	$81.56	$45.77	$ 6.6	$ —	$18.8	$ —
Calls (written)	Natural Gas	322,000	$ 5.05	$ 2.60	$ —	$ —	$ —	$ —
	NGL	372,600	$45.80	$23.58	$ —	$ —	$ —	$(0.6)
	Crude Oil	184,000	$88.39	$45.77	$ —	$ —	$ —	$(0.4)
Puts (written)	Natural Gas	1,012,000	$ 3.90	$ 2.60	$ —	$(1.3)	$ —	$(3.8)
	NGL	23,000	$77.28	$39.81	$ —	$(0.9)	$ —	$ —
Calls (purchased)	Natural Gas	322,000	$ 5.05	$ 2.60	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 2.80	$ 1.7	$ —	$ 1.0	$ —
	NGL	2,836,500	$39.24	$22.88	$48.4	$ —	$39.3	$ —
	Crude Oil	805,200	$75.91	$49.23	$21.8	$ —	$14.7	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 2.80	$ —	$ —	$ —	$(0.1)
	NGL	2,836,500	$45.14	$22.88	$ —	$(1.2)	$ —	$(3.2)
	Crude Oil	805,200	$86.68	$49.23	$ —	$(0.2)	$ —	$(2.7)
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 2.80	$ —	$(1.7)	$ —	$(1.0)
	NGL	91,500	$39.06	$25.26	$ —	$(1.3)	$ —	$ —
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 2.80	$ —	$ —	$ 0.1	$ —
	NGL	91,500	$46.41	$25.26	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,277,500	$25.26	$24.76	$ 5.5	$ —	$ 1.2	$ —
	Crude Oil	547,500	$63.00	$52.74	$ 7.5	$ —	$ 4.1	$ —
Calls (written)	NGL	1,277,500	$29.46	$24.76	$ —	$(3.0)	$ —	$(0.7)
	Crude Oil	547,500	$71.45	$52.74	$ —	$(1.1)	$ —	$(3.3)

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude any credit valuation adjustment losses of approximately $0.4 million and $0.7 million at September 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

15. 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 0.4% and 0.5% for the nine months ended September 30, 2015 and 2014, respectively. Our income tax expense was $3.7 million and $1.4 million for the three and nine months ended September 30, 2015, respectively. Our income tax expense was $0.9 million and $2.7 million for the three and nine months ended September 30, 2014, respectively.

In the third quarter of 2015, we assigned certain contracts in our Logistics and Marketing segment to a third party. Refer to Note 3. *Acquisitions and Dispositions* for more information about this transaction. This transaction increased our Texas franchise tax apportionment factor. As a result, during the three and nine months ended September 30, 2015, we incurred approximately $2.4 million of additional deferred income tax expense in our consolidated statements of income.

At September 30, 2015 and December 31, 2014, we included a current income tax payable of $1.0 million and $1.5 million, respectively, in "Property and other taxes payable" on our consolidated statements of financial position. In addition, at September 30, 2015 and December 31, 2014, we included a deferred income tax payable of

15. INCOME TAXES – (continued)

$14.4 million and $14.2 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.

The Texas Franchise Tax Reduction Act of 2015 was signed into law on June 15, 2015. The law applies to original reports filed on or after January 1, 2016, and permanently reduces Texas franchise tax rates. Specifically, the general 1.0% rate will be reduced to 0.75%. As a result of this change, we have recorded a reduction in our deferred income tax payable reflected in ‘‘Other long-term liabilities’’ on our consolidated statement of financial position of approximately $3.5 million at September 30, 2015.

16. 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.

16. SEGMENT INFORMATION – (continued)

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

	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, interest income, 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.

16. SEGMENT INFORMATION – (continued)

	For the three months ended September 30, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$646.3	$1,252.4	$ —	$1,898.7
Less: Intersegment revenue	484.9	14.4	—	499.3
Operating revenue	161.4	1,238.0	—	1,399.4
Cost of natural gas and natural gas liquids	20.7	1,217.5	—	1,238.2
Segment gross margin	140.7	20.5	—	161.2
Operating and maintenance	64.9	15.7	—	80.6
General and administrative	21.3	3.1	1.5	25.9
Depreciation and amortization	35.5	4.0	—	39.5
	121.7	22.8	1.5	146.0
Operating income (loss)	19.0	(2.3)	(1.5)	15.2
Interest expense, net	—	—	(3.6)	(3.6)
Other income	5.3[2]	—	—	5.3
Income (loss) before income tax expense	24.3	(2.3)	(5.1)	16.9
Income tax expense	—	—	(0.9)	(0.9)
Net income (loss)	$ 24.3	$ (2.3)	$ (6.0)	$ 16.0
Less: Net income attributable to noncontrolling interest	—	—	9.7	9.7
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 24.3	$ (2.3)	$(15.7)	$ 6.3

(1) Corporate consists of interest expense, interest income, 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.

16. 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 expense	(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	$ 99.6	$5,292.8
Capital expenditures (excluding acquisitions)	$ 132.8	$ 11.0	$ 3.6	$ 147.4

(1) Corporate consists of interest expense, interest income, 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) Totals assets for our Gathering, Processing and Transportation segment includes $373.7 million for our equity investment in the Texas Express NGL system.

16. SEGMENT INFORMATION – (continued)

	As of and for the nine months ended September 30, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$2,065.3	$3,981.2	$ —	$6,046.5
Less: Intersegment revenue	1,531.2	72.2	—	1,603.4
Operating revenue	534.1	3,909.0	—	4,443.1
Cost of natural gas and natural gas liquids	155.6	3,831.1	—	3,986.7
Segment gross margin	378.5	77.9	—	456.4
Operating and maintenance	196.5	49.8	0.2	246.5
General and administrative	62.4	8.8	3.5	74.7
Depreciation and amortization	105.4	7.9	—	113.3
	364.3	66.5	3.7	434.5
Operating income (loss)	14.2	11.4	(3.7)	21.9
Interest expense, net	—	—	(9.7)	(9.7)
Other income	6.4[2]	—	—	6.4
Income (loss) before income tax expense	20.6	11.4	(13.4)	18.6
Income tax expense	—	—	(2.7)	(2.7)
Net income (loss)	20.6	11.4	(16.1)	15.9
Less: Net income attributable to noncontrolling interest	—	—	13.8	13.8
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 20.6	$ 11.4	$ (29.9)	$ 2.1
Total assets	$4,955.8[3]	$ 499.2	$130.2	$5,585.2
Capital expenditures (excluding acquisitions)	$ 149.8	$ 8.6	$ 3.2	$ 161.6

(1) Corporate consists of interest expense, interest income, 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) Totals assets for our Gathering, Processing and Transportation segment includes $380.2 million for our equity investment in the Texas Express NGL system.

17. 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,	
	2015	2014
	(in millions)	
Additions to property, plant and equipment	$155.4	$166.6
Decrease in construction payables	(8.0)	(5.0)
Total capital expenditures	$147.4	$161.6

18. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, which outlines 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. In July 2015, the FASB delayed the effective date of the new revenue standard by one year. This accounting update is effective for annual and interim periods beginning after December 15, 2017 and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

Going Concern Uncertainties

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. This accounting update is effective for annual and interim periods ending after December 15, 2016, with early adoption permitted. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

Consolidation

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, which addresses concerns about the current accounting for consolidation of certain legal entities. It makes targeted amendments to the current consolidation guidance and ends the deferral granted to certain entities from applying the variable interest entity, or VIE guidance. Among other things, the amended standard eliminates the specialized consolidation model and guidance for limited partnerships, which included the presumption that the general partner should consolidate a limited partnership. This accounting update is effective for annual and interim periods beginning after December 15, 2015. Early adoption is permitted, and the new standard may be adopted either retrospectively or using a modified retrospective approach. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements, although we expect that this amended guidance will require us to (1) revisit our consolidation model and perform a VIE analysis for each limited partnership that we currently consolidate and (2) include additional disclosures within our consolidated financial statements.

Debt Issuance Costs

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, which simplifies the presentation of debt issuance costs. The standard requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, and that the amortization of the debt issuance cost should be recorded as interest expense. The amendments do not affect the current guidance on the recognition and measurement of debt issuance costs. This accounting update is effective for annual and interim periods beginning on or after December 15, 2015. Early adoption is permitted, and the new standard must be adopted retrospectively. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

Inventory Measurement

In July 2015, the FASB issued Accounting Standards Update No. 2015-11, which simplifies the subsequent measurement of inventories. For inventory within the scope of the new guidance, entities will be required to compare the cost of inventory to only one measure, its net realizable value, and not the three measures required by current guidance. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. No other changes were made to the current guidance on inventory measurement. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016. We are currently evaluating the impact that this pronouncement will have on our consolidated financial statements.

19. SUBSEQUENT EVENTS

Distribution to Partners

On October 29, 2015, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, declared a cash distribution payable to our unitholders on November 13, 2015. The distribution will be paid to unitholders of record as of November 6, 2015, of our available cash of $16.5 million at September 30, 2015, 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, L.L.C., with respect to its general partner interest.

Midcoast Operating Distribution

On October 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable on November 13, 2015 to its partners of record as of November 6, 2015. Midcoast Operating will pay $27.4 million to us and $25.7 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, 2014, as filed with the SEC on February 18, 2015.

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 a 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.

Our business primarily consists of natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and an NGL fractionation facility. 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 of 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 NGLs 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 processing plants to a wholesale customer. In addition, we also provide marketing services of natural gas and NGLs to wholesale customers.

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 buyer. Midcoast Operating subsidiaries will now sell their natural gas products directly to third parties, instead of through the Logistics and Marketing segment.

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 three and nine months ended September 30, 2015, and 2014.

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Operating income (loss)				
Gathering, Processing and Transportation	$ 16.7	$19.0	$(219.0)	$14.2
Logistics and Marketing	(11.7)	(2.3)	(60.0)	11.4
Corporate	(1.1)	(1.5)	(3.9)	(3.7)
Total operating income (loss)	3.9	15.2	(282.9)	21.9
Interest expense, net	(7.6)	(3.6)	(21.5)	(9.7)
Other income	8.5	5.3	20.3	6.4
Income tax expense	(3.7)	(0.9)	(1.4)	(2.7)
Net income (loss)	$ 1.1	$16.0	$(285.5)	$15.9

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. Some of these derivative financial instruments do not receive hedge accounting under the provisions of authoritative accounting guidance, which can 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,	
	2015	2014	2015	2014
	(in millions)			
Gathering, Processing and Transportation segment:				
Hedge ineffectiveness	$ (0.1)	$ 0.9	$ (4.1)	$ 1.5
Non-qualified hedges	10.1	8.7	(31.4)	(1.9)
Logistics and Marketing segment:				
Non-qualified hedges	(3.9)	8.1	(18.0)	11.9
Derivative fair value net gains (losses)	$ 6.1	$17.7	$(53.5)	$11.5

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 and NGL fractionation facilities. 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,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues	$ 143.4	$ 161.4	$ 367.6	$ 534.1
Cost of natural gas and natural gas liquids	16.7	20.7	58.5	155.6
Segment gross margin	126.7	140.7	309.1	378.5
Operating and maintenance	55.7	64.9	161.5	196.5
General and administrative	17.2	21.3	48.5	62.4
Goodwill impairment	—	—	206.1	—
Depreciation and amortization	37.1	35.5	112.0	105.4
Operating expenses	110.0	121.7	528.1	364.3
Operating income (loss)	16.7	19.0	(219.0)	14.2
Other income	8.9	5.3	20.5	6.4
Net income (loss)	$ 25.6	$ 24.3	$ (198.5)	$ 20.6
Operating Statistics (MMBtu/d):				
East Texas	966,000	1,063,000	981,000	1,021,000
Anadarko	760,000	806,000	794,000	816,000
North Texas	262,000	304,000	274,000	292,000
Total	1,988,000	2,173,000	2,049,000	2,129,000
NGL Production (Bpd)	85,343	84,121	82,498	82,845

Three months ended September 30, 2015, compared with the three months ended September 30, 2014

The operating income of our Gathering, Processing and Transportation segment for the three months ended September 30, 2015, decreased $2.3 million, as compared with the same period in 2014. The area most affected was segment gross margin, which decreased $14.0 million for the three months ended September 30, 2015, as compared with the same period in 2014.

Segment gross margin decreased $7.7 million for the three months ended September 30, 2015, as compared with the same period in 2014, due to decreased margins from lower commodity prices, net of hedges, related to contracts where we were paid in commodities for our services.

Segment gross margin decreased by approximately $5.0 million for the three months ended September 30, 2015, as compared to the same period in 2014, due to reduced natural gas production volumes. The average daily volumes of our major systems for the three months ended September 30, 2015, decreased by 185,000 MMBtu/d, or 9%, when compared to the same period in 2014. The average NGL production for the three months ended September 30, 2015, increased by 1,222 Bpd, or 1%, when compared to the same period in 2014, primarily due to the completion of the Beckville processing plant in the second quarter of 2015 enabling additional production from

East Texas. The decrease in natural gas volumes was primarily attributable to the continued low commodity price environment for natural gas and condensate, resulted in reductions in drilling activity from producers in the areas we operate.

Operating and maintenance and general and administrative costs together decreased $13.3 million for the three months ended September 30, 2015, compared to the same period in 2014, primarily due to work force reductions and other cost reduction efforts, which resulted in a decrease in contract labor as well as other related cost benefits.

Depreciation and amortization expense increased $1.6 million for the three months ended September 30, 2015, compared with the same period of 2014, due to additional assets that were placed into service.

Other income increased $3.6 million for the three months ended September 30, 2015, compared to the same period in 2014, as a result of increases in equity earnings on our investment in the Texas Express NGL system primarily due to higher volumes in the third quarter of 2015 and increases in ship-or-pay commitments.

Nine months ended September 30, 2015, compared with the nine months ended September 30, 2014

The operating income of our Gathering, Processing and Transportation segment for the nine months ended September 30, 2015, decreased $233.2 million, as compared with the same period of 2014, primarily due to the $206.1 million goodwill impairment charge recorded during 2015. We performed a goodwill impairment analysis after we learned from customers, during the second quarter 2015 that reductions in drilling will be prolonged in the producing basins in which we operate due to the continued low commodity price environment. As a result of this analysis, we determined that $206.1 million in goodwill was impaired. In the longer term, we expect our performance to strengthen although the pace and magnitude of improvement is less than we previously expected given the length of recovery in commodity prices and related supply and demand fundamentals anticipated in the market.

Segment gross margin decreased $69.4 million for the nine months ended September 30, 2015, as compared with the same period in 2014, in part due to a decrease of $35.1 million from non-cash, mark-to-market losses of $35.5 million and $0.4 million for the nine months ended September 30, 2015 and September 30, 2014, respectively. These losses are primarily related to the reclassification of previously recognized unrealized market-to-market gains as the underlying transactions were settled.

Segment gross margin decreased $21.4 million for the nine months ended September 30, 2015, as compared with the same period in 2014, due to decreased margins from lower commodity prices, net of hedges, related to contracts where we were paid in commodities for our services.

Segment gross margin decreased $13.0 million, compared to the same period in 2014, due to reduced production volumes. The average daily volumes of our major systems for the nine months ended September 30, 2015, decreased by approximately 80,000 MMBtu/d, or 4%, when compared to the same period in 2014. The decrease in natural gas volumes was primarily attributable to the continued low commodity price environment for natural gas and condensate, which has resulted in reductions in drilling activity from producers in the areas we operate. The average NGL production for the nine months ended September 30, 2015, was relatively flat, when compared to the same period in 2014.

Operating and maintenance and general and administrative costs together decreased $48.9 million for the nine months ended September 30, 2015, compared to the same period in 2014, primarily due to work force reductions and other cost reduction efforts, which resulted in a decrease in contract labor as well as other related cost benefits.

Depreciation and amortization expense increased $6.6 million, for the nine months ended September 30, 2015, compared with the same period of 2014, due to additional assets that were placed into service.

Other income increased $14.1 million for the nine months ended September 30, 2015, compared to the same period in 2014, as a result of increases in equity earnings on our investment in the Texas Express NGL system primarily due to higher volumes in the third quarter of 2015 and increases in ship-or-pay commitments.

Future Prospects for Gathering, Processing and Transportation

We intend 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. We will pursue internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value.

Impact of Commodity Prices

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 have remained low throughout 2015. The depressed commodity price environment is the most significant factor for reduced drilling activity and low volumes in the basins in which we operate. Producers remain cautious in the current commodity price environment, and we expect that drilling activity will continue to remain low and as a result expect to see a modest decrease in volumes for the remainder of 2015.

We have largely mitigated our near-term direct commodity risk through our hedging program. We have hedged 90% for the remainder of 2015 and over 80% for 2016 of our direct commodity price exposure. 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 improve as prices improve.

Expansion Projects

The following expansion projects are designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity. The paragraphs below summarize our commercially secured projects that we have placed into service in 2015 or expect to place into service in future periods.

Beckville Cryogenic Processing Plant

In May 2015, we placed into service a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant serves existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas and has been a steady producer of natural gas for decades, as well as the Eaglebine developments. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. Our Beckville processing plant is capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas within this geographical area in which our East Texas system operates. Related NGL takeaway infrastructure connecting the Beckville plant to third-party NGL transportation systems was also constructed. This project cost approximately $165.0 million.

The project was funded by us and EEP based on our proportionate ownership percentages in Midcoast Operating, which currently are 51.6% and 48.4%, respectively.

Eaglebine Developments

The Eaglebine is an emerging oil play in East Texas that spans over five counties and is comprised of multiple formations, including but not limited to, the Woodbine, Buda, Glenrose and Eagle Ford formations. We have a series of construction projects and an acquisition in this play. We have commenced construction of the Ghost Chili pipeline project, which consists of a lateral and associated facilities that will create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. The initial facilities were placed in service in October 2015. We also expect to construct the Ghost Chili Extension Lateral by late 2016 to fully utilize this gathering capacity with the rest of our processing assets. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

On February 27, 2015, we acquired from NGR its midstream operations in Leon, Madison and Grimes counties, Texas. The acquisition consists of a natural gas gathering system currently in operation. For further details regarding the NGR acquisition, refer to Item 1. *Financial Statements,* Note 3. *Acquisitions and Dispositions*.

We estimate the aggregate cost of our Eaglebine projects and acquisitions described above to be approximately $160.0 million, of which $125.0 million is estimated to be spent in 2015. Funding is to be provided by us and EEP based on our proportionate ownership percentages in Midcoast Operating.

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, such as 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 access to several interstate natural gas pipelines over the past several years. We can use our connectivity to interstate pipelines to improve value for the producers by transporting natural gas to premium markets and NGLs to primary markets where we can 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 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. Midcoast Operating subsidiaries will now sell their natural gas products directly to third parties, instead of through the Logistics and Marketing segment.

The following table sets forth the operating revenues and cost of natural gas and natural gas liquids of these subsidiaries in the Logistics and Marketing segment for the periods presented:

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues	$121.1	$626.0	$898.0	$1,673.0
Cost of natural gas and natural gas liquids	116.1	614.1	886.6	1,660.2
Segment gross margin	$ 5.0	$ 11.9	$ 11.4	$ 12.8

While we expect that operating revenues and cost of natural gas and natural gas liquids will be significantly reduced in future periods due to this transaction, we do not expect a significant impact on segment gross margin as a result.

Generally, the demand for natural gas and NGLs is higher during the winter months as these commodities are used to meet residential and commercial heating requirements. In some areas during the summer months, demand for natural gas is higher as utility companies that use natural gas for power generation increase their electricity output to meet residential and commercial demand for air conditioning. Seasonal anomalies such as mild winters or hot summers can lessen or intensify these fluctuations.

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,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues	$517.6	$1,238.0	$1,947.0	$3,909.0
Cost of natural gas and natural gas liquids	506.0	1,217.5	1,913.9	3,831.1
Segment gross margin	11.6	20.5	33.1	77.9
Operating and maintenance	18.2	15.7	45.1	49.8
General and administrative	3.0	3.1	9.0	8.8
Goodwill impairment	—	—	20.4	—
Asset impairment	—	—	12.3	—
Depreciation and amortization	2.1	4.0	6.3	7.9
Operating expenses	23.3	22.8	93.1	66.5
Operating income (loss)	$ (11.7)	$ (2.3)	$ (60.0)	$ 11.4

Three months ended September 30, 2015, compared with the three months ended September 30, 2014

The operating loss of our Logistics and Marketing segment for the three months ended September 30, 2015 increased $9.4 million, as compared with the same period in 2014. The area most affected was segment gross margin, which decreased $8.9 million for the three months ended September 30, 2015, as compared with the same period in 2014. Decreases in ''Operating revenues'' and ''Cost of natural gas and natural gas liquids'' for the three months ended September 30, 2015, as compared with the same period in 2014, are primarily due to decreases in commodity prices and the resulting decreased volumes from lower drilling activities.

Segment gross margin experienced a net decrease of $10.4 million, exclusive of $1.6 million gains associated with the assignments of certain natural gas contracts, due to non-cash, mark-to-market losses for the three months ended September 30, 2015, as compared with the same period in 2014. These losses are primarily related to the reclassification of previously recognized unrealized market-to-market gains as the underlying transactions were settled.

Our segment gross margin also decreased $9.3 million for the three months ended September 30, 2015, as compared with the same period in 2014, due to costs associated with the sale of certain natural gas inventories, and assignment of certain storage agreements, transportation contracts and other arrangements to a third party.

Our segment gross margin increased $8.8 million for the three months ended September 30, 2015, compared with the same period in 2014, due to higher storage margins as a result of sale of liquids product inventory at prevailing market prices relative to the cost of product inventory.

Our segment gross margin also increased $1.4 million for the three months ended September 30, 2015, when compared to the same period of 2014, for decreases non-cash charges to decrease the cost basis of our natural gas inventory to net realizable value recorded in 2014. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

Operating and maintenance and general and administrative costs together increased $2.4 million for the three months ended September 30, 2015, compared with the three months ended September 30, 2014. These increases are primarily due to the loss on disposal of our non-core Tinsley crude oil and Louisiana propylene pipelines and severance costs associated with a reduction in workforce related to fewer commercial and support personnel for our gas marketing business after entering into our arrangement with a third party, offset by workforce reductions and other cost reduction efforts.

Nine months ended September 30, 2015, compared with the nine months ended September 30, 2014

The operating income of our Logistics and Marketing segment for the nine months ended September 30, 2015, decreased $71.4 million, as compared with the same period in 2014. The area most affected was segment gross margin which decreased $44.8 million for the nine months ended September 30, 2015, as compared with the same period in 2014. In addition, the Logistics and Marketing segment recognized a $20.4 million goodwill impairment charge for the nine months ended September 30, 2015 and a non-cash impairment charge of $12.3 million from an expected loss on disposal of our non-core, held-for-sale assets that were recorded during the nine months ended September 30, 2015. The goodwill impairment resulted from the impacts on our marketing business from sustained reductions in drilling activities in the areas in which our Gathering, Processing and Transportation segment operates. Decreases in ‘‘Operating revenues’’ and ‘‘Cost of natural gas and natural gas liquids’’ for the nine months ended September 30, 2015, as compared with the same period in 2014, are primarily due to decreases in commodity prices and the resulting decreased volumes from lower drilling activities.

Segment gross margin experienced a net decrease of $28.3 million, exclusive of $1.6 million gains associated with the assignments of certain natural gas contracts, due to non-cash, mark-to-market losses for the nine months ended September 30, 2015, as compared with the same period in 2014. These losses are primarily related to the reclassification of previously recognized unrealized market-to-market gains as the underlying transactions were settled.

Our segment gross margin also decreased $9.3 million for the nine months ended September 30, 2015, as compared with the same period in 2014, due to costs associated with the sale of certain natural gas inventories, and assignment of certain storage agreements, transportation contracts and other arrangements to a third party.

Our segment gross margin was impacted by decreased margins within our gas marketing function due to price differentials between market centers by approximately $8.1 million for the nine months ended September 30, 2015, when compared to the same period of 2014. During the first quarter of 2014, we benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest which arose due to higher than usual demand from winter weather conditions in the Midwest.

Our segment gross margin increased $2.3 million for the nine months ended September 30, 2015, compared with the same period in 2014, due to higher storage margins as a result of sale of liquids product inventory at prevailing market prices relative to the cost of product inventory.

Operating and maintenance and general and administrative costs together decreased $4.5 million for the nine months ended September 30, 2015, as compared with the same period in 2014, primarily due to a decrease in outside contract labor as well as other related benefit costs due to workforce reductions in December 2014. In addition, other cost reduction efforts have resulted in reduced repairs and maintenance costs.

Corporate

Our corporate results consist of interest expense, interest income 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,	
	2015	2014	2015	2014
	(in millions)			
Operating and maintenance	$ 0.1	$ —	$ 0.3	$ 0.2
General and administrative	1.0	1.5	3.6	3.5
Operating expenses	1.1	1.5	3.9	3.7
Operating loss	(1.1)	(1.5)	(3.9)	(3.7)
Interest expense, net	(7.6)	(3.6)	(21.5)	(9.7)
Other loss	(0.4)	—	(0.2)	—
Loss before income tax expense	(9.1)	(5.1)	(25.6)	(13.4)
Income tax expense	(3.7)	(0.9)	(1.4)	(2.7)
Net loss	$(12.8)	$(6.0)	$(27.0)	$(16.1)

Three months ended September 30, 2015, compared with the three months ended September 30, 2014

Interest expense increased $4.0 million for the three months ended September 30, 2015, as compared to the same period in 2014 primarily due to interest expense on our senior notes, which were issued in a private placement offering in September 2014.

Our income tax expense increased $2.8 million for the three months ended September 30, 2015, as compared to the same period in 2014 primarily due to the $2.4 million of additional deferred income tax expense. In the third quarter of 2015, we assigned certain storage agreements, transportation contracts and other agreements to a third party. This transaction increased our apportionment factor for Texas state franchise tax, which resulted in increased deferred income tax expense. Refer to Note 15. *Income Taxes* for more information about this transaction.

Nine months ended September 30, 2015, compared with the nine months ended September 30, 2014

Interest expense increased $11.8 million for the nine months ended September 30, 2015, as compared to the same period in 2014 primarily due to interest expense on our senior notes, which were issued in a private placement offering in September 2014.

Our income tax expense decreased $1.3 million for the nine months ended September 30, 2015, as compared to the same period in 2014 primarily due to a $3.5 million tax benefit from a reduction in deferred income tax payable. This reduction is the result of a reduction in the Texas franchise tax rate from the recently-enacted Texas Franchise Tax Reduction Act of 2015. This reduction was partially offset by an increase in deferred income taxes of $2.4 million due to an increase in our apportionment factor for the Texas state franchise tax, as described above.

LIQUIDITY AND CAPITAL RESOURCES

Our ongoing sources of liquidity include cash generated from operations of Midcoast Operating, borrowings under our senior revolving credit facility, which we refer to as the Credit Agreement, and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements and to make quarterly cash distributions to our unitholders.

One of our key strengths is our sponsorship from EEP. On July 29, 2015, the partners of Midcoast Operating approved an amendment to Midcoast Operating's limited partnership agreement that would potentially enhance our distributable cash flow, demonstrating EEP's further support of our ongoing cash distribution strategy and growth outlook. The amendment provides a mechanism for us to receive increased quarterly distributions from Midcoast Operating and for EEP to receive reduced quarterly distributions if our declared distribution exceeds our distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement. 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. The amendment to the limited partnership agreement and the support it provides to our cash distribution is effective with the quarter ended June 30, 2015, and continues through and including the distribution made for the quarter ending December 31, 2017. Through September 30, 2015, we have not received an increased allocation of cash distributions from Midcoast Operating as the distributable cash flow we generated exceeded the cash distribution amount we declared.

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.

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.

Available Liquidity

Our primary source of liquidity is provided by the Credit Agreement, the sources and uses of which at September 30, 2015, are set forth in the following table.

	(in millions)
Cash and cash equivalents	$ 15.6
Total credit available under Credit Agreement	810.0
Amounts outstanding under Credit Agreement	(420.0)
Total	$ 405.6

As of September 30, 2015, we had a working capital deficit of approximately $38.4 million and approximately $405.6 million of liquidity, as shown above, to meet our ongoing operational, investment and financing needs.

Equity and Debt Financing Activities

Credit Agreement

We, Midcoast Operating, and our material domestic subsidiaries are parties to the Credit Agreement, which previously permitted aggregate borrowings of up to, at any one time outstanding, $850.0 million. On September 3, 2015 we amended our Credit Agreement and decreased the aggregate commitments to $810.0 million. The original term of the Credit Agreement was three years subject to four one-year requests for extensions. On September 3, 2015, we further amended our Credit Agreement to extend the maturity date from September 30, 2017 to 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, 2015, we had $420.0 million in outstanding borrowings under the Credit Agreement at a weighted-average interest rate of 2.67%. Under the Credit Agreement, we had net borrowings of approximately $60.0 million during the nine months ended September 30, 2015, which includes gross borrowings of $4,160.0 million and gross repayments of $4,100.0 million. At September 30, 2015, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Senior Notes

Our senior notes in the aggregate amount of $400.0 million were issued in a private placement and consist of three tranches: $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, which commenced on March 31, 2015. At September 30, 2015, we were in compliance with the terms of our financial covenants under the note purchase agreement, pursuant to which we issued and sold the senior notes.

Financial Support Agreement

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.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the offer and sale of debt or equity securities in public offerings. In December 2014, we filed a shelf registration statement on Form S-3 with the SEC, which became effective on February 5, 2015, with a proposed aggregate offering price for all securities registered of $1.5 billion.

Cash Requirements

Capital Spending

We categorize our capital expenditures as either maintenance capital 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 our revolving credit facility, with long-term debt and equity funding being obtained when needed and as market conditions allow.

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.

For the nine months ended September 30, 2015, Midcoast Operating incurred capital expenditures of approximately $235.4 million, including $85.0 million for our NGR acquisition, $28.5 million for maintenance capital activities and $3.0 million for contributions to fund our joint ventures. At September 30, 2015, we had approximately $17.7 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

We 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 expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under the Credit Agreement 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, EEP has indicated that it intends to 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 $150.0 million for the year ending December 31, 2015. Although we anticipate making these expenditures in 2015, 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	
Beckville Cryogenic Processing Plant	$ 60
Eaglebine Developments	125
Compression Capital	10
Wellconnect Expansion Capital	25
Expansion Capital	30
Maintenance Capital Expenditure Activities	40
	290
Less: Joint Funding from:	
EEP[1]	140
	$150

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

Derivative Activities

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. 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 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 the 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, 2015, for each of the indicated calendar years:

	Notional[1]	2015	2016	2017	2018	2019 & Thereafter	Total[2]
				(in millions)			
Swaps:							
Natural gas	14,094,817	$ (0.1)	$ 0.1	$ 0.4	$ —	$ —	$ 0.4
NGL	6,234,800	7.7	7.4	(1.2)	—	—	13.9
Crude Oil	2,685,620	4.7	1.0	—	—	—	5.7
Options:							
Natural gas – puts purchased	2,659,000	1.3	1.7	—	—	—	3.0
Natural gas – puts written	2,659,000	(1.3)	(1.7)	—	—	—	(3.0)
Natural gas – calls written	1,969,000	—	—	—	—	—	—
Natural gas – calls purchased	1,969,000	—	—	—	—	—	—
NGL – puts purchased	4,693,600	11.4	48.4	5.5	—	—	65.3
NGL – puts written	114,500	(0.9)	(1.3)	—	—	—	(2.2)
NGL – calls written	4,486,600	—	(1.2)	(3.0)	—	—	(4.2)
NGL – calls purchased	91,500	—	—	—	—	—	—
Crude Oil – puts purchased	1,536,700	6.6	21.8	7.5	—	—	35.9
Crude Oil – calls written	1,536,700	—	(0.2)	(1.1)	—	—	(1.3)
Forward contracts:							
Natural gas	239,322,704	(0.8)	(3.4)	0.1	0.1	0.1	(3.9)
NGL	18,123,928	7.4	1.5	—	—	—	8.9
Crude Oil	805,442	(0.4)	—	—	—	—	(0.4)
Totals		$35.6	$74.1	$ 8.2	$0.1	$0.1	$118.1

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

(2) Excludes $16.2 million of cash collateral at September 30, 2015.

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, 2015	For the nine months ended September 30, 2014	Variance 2015 vs. 2014 Increase (Decrease)
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 198.6	$ 112.0	$ 86.6
Investing activities	(160.2)	(120.2)	(40.0)
Financing activities	(22.8)	69.5	(92.3)
Net increase in cash and cash equivalents	15.6	61.3	(45.7)
Cash and cash equivalents at beginning of year	—	4.9	(4.9)
Cash and cash equivalents at end of period	$ 15.6	$ 66.2	$(50.6)

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

	For the nine months ended September 30, 2015	2014	Variance 2015 vs. 2014
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 13.9	$ 11.5	$ 2.4
Due from General Partner and affiliates	38.7	641.7	(603.0)
Accrued receivables	200.6	28.0	172.6
Inventory	(9.8)	(129.1)	119.3
Current and long-term other assets	1.8	(11.5)	13.3
Due to General Partner and affiliates	13.3	(487.4)	500.7
Accounts payable and other	(20.6)	(50.6)	30.0
Environmental liabilities	—	0.2	(0.2)
Accrued purchases	(177.2)	(21.3)	(155.9)
Interest payable	(3.8)	0.4	(4.2)
Property and other taxes payable	5.4	6.6	(1.2)
Net change in working capital accounts	$ 62.3	$ (11.5)	$ 73.8

Operating Activities

Net cash provided by our operating activities increased $86.6 million for the nine months ended September 30, 2015, as compared to the same period in 2014, primarily due to increased cash from net changes in operating assets and liabilities of $73.8 million. The increase is primarily the result of general timing differences for cash receipts and payments and includes:

- Net increased cash from accrued receivables and accrued purchases of $16.7 million, primarily resulting from lower prices and volumes of natural gas and NGLs;
- Increased cash from inventory of $119.3 million primarily resulting from lower prices of natural gas and NGLs offset by seasonal volume increases;
- Decreased cash from net balances due to and due from the General Partner and its affiliates of $102.3 million resulting from the absence of transitional cash management functions that were provided to us by EEP following the Offering.

Investing Activities

Net cash used in our investing activities during the nine months ended September 30, 2015, increased by $40.0 million, compared to the same period in 2014, primarily due to:

- Increased cash used for acquisition of assets of $43.9 million due to the purchase of NGR's midstream assets in February 2015. For further details regarding this acquisition, refer to Item 1. *Financial Statements*, Note 3. *Acquisitions and Dispositions*;
- Decreased cash provided by restricted cash of $23.5 million resulting from fewer amounts remitted to the Enbridge subsidiary for sales of our receivables in accordance with our Receivables Agreement; and
- Decreased cash used for contributions to fund our joint venture investment in the Texas Express NGL system of $32.4 million.

Financing Activities

Net cash provided by our financing activities decreased $92.3 million for the nine months ended September 30, 2015, compared to the same period in 2014, due to:

- Decreased cash provided by the issuance of debt of $398.1 million in 2014 with no similar activity during 2015;
- Decreased cash provided by contributions from noncontrolling interest of $74.5 million primarily due to EEP's decreased ownership in Midcoast Operating;

- Decreased cash used for payments to EEP for acquiring a portion of its noncontrolling interest in Midcoast Operating in 2014 of $350.0 with no similar activity in 2015; and
- Increased cash from net borrowings on the Credit Facility of $30.0 million.

SUBSEQUENT EVENTS

Distribution to Partners

On October 29, 2015, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, declared a cash distribution payable to our unitholders on November 13, 2015. The distribution will be paid to unitholders of record as of November 6, 2015, of our available cash of $16.5 million at September 30, 2015, 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, L.L.C., with respect to its general partner interest.

Midcoast Operating Distribution

On October 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable on November 13, 2015 to its partners of record as of November 6, 2015. Midcoast Operating will pay $27.4 million to us and $25.7 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 10-K for the fiscal year ended December 31, 2014, filed on February 18, 2015, 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 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.

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, 2015 and December 31, 2014.

	At September 30, 2015						At December 31, 2014	
			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 2015								
Swaps								
Receive variable/pay fixed	NGL	964,000	$22.66	$25.42	$ 0.7	$ (3.3)	$ —	$ (6.8)
	Crude Oil	350,000	$45.54	$72.70	$ —	$ (9.5)	$ —	$(27.4)
Receive fixed/pay variable	NGL	1,913,800	$29.66	$24.25	$11.3	$ (1.0)	$39.2	$ —
	Crude Oil	398,720	$81.28	$45.63	$14.2	$ —	$42.4	$ —
Receive variable/pay variable	Natural Gas	828,000	$ 2.45	$ 2.52	$ —	$ (0.1)	$ 1.5	$ (1.7)
Physical Contracts								
Receive variable/pay fixed	NGL	50,000	$31.63	$33.02	$ —	$ (0.1)	$ —	$ (3.6)
	Crude Oil	8,600	$45.26	$45.12	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	3,048,988	$18.83	$17.16	$ 6.4	$ (1.3)	$19.8	$ —
	Crude Oil	54,500	$42.69	$45.80	$ —	$ (0.2)	$ 0.5	$ —
Receive variable/pay variable	Natural Gas	54,524,000	$ 2.48	$ 2.49	$ —	$ (0.8)	$ 2.2	$ (1.0)
	NGL	5,150,479	$20.54	$20.07	$ 5.3	$ (2.9)	$ 3.7	$ (1.0)
	Crude Oil	742,342	$43.59	$43.90	$ 1.3	$ (1.5)	$ 0.3	$ (1.7)
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 2.72	$ 3.48	$ —	$ —	$ —	$ (0.1)
	NGL	833,500	$23.81	$30.54	$ —	$ (5.6)	$ —	$ —
	Crude Oil	415,950	$49.02	$82.69	$ —	$(14.0)	$ —	$ (8.1)
Receive fixed/pay variable	NGL	1,428,500	$31.34	$22.26	$13.3	$ (0.3)	$ 9.3	$ —
	Crude Oil	425,950	$84.17	$48.95	$14.9	$ —	$ 9.1	$ —
Receive variable/pay variable	Natural Gas	5,124,000	$ 2.79	$ 2.76	$ 0.2	$ —	$ 0.5	$ (0.3)
Physical Contracts								
Receive fixed/pay variable	NGL	233,952	$20.02	$19.25	$ 0.2	$ (0.1)	$ —	$ —
Receive variable/pay variable	Natural Gas	177,875,634	$ 2.62	$ 2.64	$ —	$ (3.4)	$ 0.7	$ (0.4)
	NGL	9,640,509	$17.02	$16.88	$ 1.6	$ (0.2)	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	76,530	$ 2.62	$ 2.97	$ —	$ —	$ —	$ —
	NGL	547,500	$19.97	$25.86	$ —	$ (3.2)	$ —	$ —
	Crude Oil	547,500	$52.74	$66.72	$ —	$ (7.6)	$ —	$ —
Receive fixed/pay variable	NGL	547,500	$23.59	$19.97	$ 2.0	$ —	$ 0.7	$ —
	Crude Oil	547,500	$66.78	$52.74	$ 7.6	$ —	$ 0.8	$ —
Receive variable/pay variable	Natural Gas	8,050,000	$ 2.82	$ 2.77	$ 0.4	$ —	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.03	$ 3.01	$ 0.1	$ —	$ 0.2	$ (0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.16	$ 3.14	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.25	$ 3.22	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.55	$ 3.52	$ —	$ —	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains (losses) of approximately $0.4 million and ($0.4) million at September 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity options at September 30, 2015 and December 31, 2014.

	At September 30, 2015						At December 31, 2014	
					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 2015								
Puts (purchased)	Natural Gas	1,012,000	$ 3.90	$ 2.60	$ 1.3	$ —	$ 3.8	$ —
	NGL	579,600	$43.32	$23.75	$11.4	$ —	$40.2	$ —
	Crude Oil	184,000	$81.56	$45.77	$ 6.6	$ —	$18.8	$ —
Calls (written)	Natural Gas	322,000	$ 5.05	$ 2.60	$ —	$ —	$ —	$ —
	NGL	372,600	$45.80	$23.58	$ —	$ —	$ —	$(0.6)
	Crude Oil	184,000	$88.39	$45.77	$ —	$ —	$ —	$(0.4)
Puts (written)	Natural Gas	1,012,000	$ 3.90	$ 2.60	$ —	$(1.3)	$ —	$(3.8)
	NGL	23,000	$77.28	$39.81	$ —	$(0.9)	$ —	$ —
Calls (purchased)	Natural Gas	322,000	$ 5.05	$ 2.60	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 2.80	$ 1.7	$ —	$ 1.0	$ —
	NGL	2,836,500	$39.24	$22.88	$48.4	$ —	$39.3	$ —
	Crude Oil	805,200	$75.91	$49.23	$21.8	$ —	$14.7	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 2.80	$ —	$ —	$ —	$(0.1)
	NGL	2,836,500	$45.14	$22.88	$ —	$(1.2)	$ —	$(3.2)
	Crude Oil	805,200	$86.68	$49.23	$ —	$(0.2)	$ —	$(2.7)
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 2.80	$ —	$(1.7)	$ —	$(1.0)
	NGL	91,500	$39.06	$25.26	$ —	$(1.3)	$ —	$ —
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 2.80	$ —	$ —	$ 0.1	$ —
	NGL	91,500	$46.41	$25.26	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,277,500	$25.26	$24.76	$ 5.5	$ —	$ 1.2	$ —
	Crude Oil	547,500	$63.00	$52.74	$ 7.5	$ —	$ 4.1	$ —
Calls (written)	NGL	1,277,500	$29.46	$24.76	$ —	$(3.0)	$ —	$(0.7)
	Crude Oil	547,500	$71.45	$52.74	$ —	$(1.1)	$ —	$(3.3)

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude any credit valuation adjustment losses of approximately $0.4 million and $0.7 million at September 30, 2015 and December 31, 2014, respectively, 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.

	September 30, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality[(1)]		
AAA	$ 0.2	$ 0.1
AA[(2)]	67.7	74.4
A	29.6	67.1
Lower than A	4.4	18.0
	$101.9	$159.6

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

(2) Includes $16.2 million and $28.4 million of cash collateral at September 30, 2015 and December 31, 2014, respectively.

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, 2015. 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, 2015.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, Note 13. *Commitments and Contingencies*, which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014, filed with the SEC on February 18, 2015.

Item 5. Other Information

The Indemnification Agreement is qualified in its entirety by reference to the complete text of such amendment filed as Exhibit 10.1 hereto, which is hereby incorporated herein by reference.

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 30, 2015

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

Date: October 30, 2015

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*	Form of Indemnification Agreement of Midcoast Holdings, L.L.C., together with a schedule of individuals who entered into an agreement in substantially the same form and the date of the agreement.
10.2	Amendment No. 2 to Credit Agreement and Extension Agreement, dated as of September 3, 2015, 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 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on September 9, 2015).
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 10.1

MIDCOAST HOLDINGS, L.L.C.

FORM OF INDEMNIFICATION AGREEMENT

This Indemnification Agreement (''Agreement'') is entered into as of [ ] by and between Midcoast Holdings, L.L.C. (the ''Company'') and [ ] (''Indemnitee'').

RECITALS

A. The Company is the general partner of Midcoast Energy Partners, L.P. (the ''Partnership'').

B. The Company and Indemnitee recognize the significant increases in the cost of liability insurance for the Company's directors, officers, employees, agents and fiduciaries.

C. The Company and Indemnitee further recognize the substantial increase in corporate litigation in general, subjecting directors, officers, employees, agents and fiduciaries to expensive litigation risks at the same time as the availability and coverage of liability insurance has been severely limited.

D. Indemnitee does not regard the current protection available as adequate under the present circumstances, and Indemnitee and other directors, officers, employees, agents and fiduciaries of the Company may not be willing to continue to serve in such capacities without additional protection.

E. The Company desires to attract and retain the services of highly qualified individuals, such as Indemnitee, to serve the Company and, in part, in order to induce Indemnitee to continue to provide services to the Company, wishes to provide for the indemnification and advancing of expenses to Indemnitee to the maximum extent permitted by law.

F. In view of the considerations set forth above, the Company desires that Indemnitee be indemnified by the Company as set forth herein.

NOW, THEREFORE, the Company and Indemnitee hereby agree as follows:

1. Indemnification.

(a) Indemnification of Expenses. The Company shall indemnify Indemnitee to the fullest extent permitted by law if Indemnitee was or is or becomes a party to or witness or other participant in, or is threatened to be made a party to or witness or other participant in, any threatened, pending or completed action, suit, proceeding or alternative dispute resolution mechanism, or any hearing, inquiry or investigation that Indemnitee in good faith believes might lead to the institution of any such action, suit, proceeding or alternative dispute resolution mechanism, whether civil, criminal, administrative, investigative or other (hereinafter a ''Claim'') by reason of (or arising in part out of) any event or occurrence related to the fact that Indemnitee is or was a director, officer, employee, agent or fiduciary of the Company, or director, manager, officer, employee, agent or fiduciary of any subsidiary of the Company, or is or was serving at the request of the Company as a director, manager, officer, employee, agent or fiduciary of another corporation, limited liability company, partnership, limited partnership, joint venture, trust or other enterprise, or by reason of any action or inaction on the part of Indemnitee while serving in such capacity (hereinafter an ''Indemnifiable Event'') against any and all expenses (including attorneys' fees and all other costs, expenses and obligations incurred in connection with investigating, defending, asserting a counterclaim in (if such counterclaim is approved in advance by the Company), being a witness in or participating in (including on appeal), or preparing to defend, assert a counterclaim in (if such counterclaim is approved in advance by the Company), be a witness in or participate in, any such action, suit, proceeding, alternative dispute resolution mechanism, hearing, inquiry or investigation), judgments, fines, penalties and amounts paid in settlement (if such settlement is approved in advance by the Company, which approval shall not be unreasonably withheld) of such Claim, and any federal, state, local or foreign taxes imposed on Indemnitee as a result of the actual or deemed receipt of any payments from the Company under this Agreement (collectively, hereinafter ''Expenses''), including all interest, assessments and other charges paid or payable in connection with or in respect of such Expenses. Such payment of Expenses shall be made by the Company as soon as practicable but in any event no later than five days after written demand by Indemnitee therefor is presented to the Company.

(b) Reviewing Party. Notwithstanding the foregoing, (i) the obligations of the Company under Section 1(a) shall be subject to the condition that the Reviewing Party (as described in Section 10(c) hereof) shall not have determined that Indemnitee would not be permitted to be indemnified under applicable law, and (ii) the obligation of the Company to make an advance payment of Expenses to Indemnitee pursuant to Section 2(a) (an ''Expense Advance'') shall be subject to the condition that, if, when and to the extent that the Reviewing Party determines that Indemnitee would not be permitted to be so indemnified under applicable law, the Company shall be entitled to be reimbursed by Indemnitee (who hereby agrees to reimburse the Company) for all such amounts theretofore paid; provided, however, that if Indemnitee has commenced or thereafter commences legal proceedings in a court of competent jurisdiction to secure a determination that Indemnitee should be indemnified under applicable law, any determination made by the Reviewing Party that Indemnitee would not be permitted to be indemnified under applicable law shall not be binding and Indemnitee shall not be required to reimburse the Company for any Expense Advance until a final judicial determination is made with respect thereto (as to which all rights of appeal therefrom have been exhausted or lapsed). Indemnitee's obligation to reimburse the Company for any Expense Advance shall be unsecured and no interest shall be charged thereon. The Reviewing Party shall be selected by the Board of Directors. If there has been no determination by the Reviewing Party or if the Reviewing Party determines that Indemnitee substantively would not be permitted to be indemnified in whole or in part under applicable law, Indemnitee shall have the right to commence litigation seeking a determination by the court or challenging any such determination by the Reviewing Party or any aspect thereof, including the legal or factual bases therefor, and the Company hereby consents to service of process and to appear in any such proceeding. Any determination by the Reviewing Party otherwise shall be conclusive and binding on the Company and Indemnitee.

(c) Mandatory Payment of Expenses. Notwithstanding any other provision of this Agreement other than Section 8 hereof, to the extent that Indemnitee has been successful on the merits or otherwise, including, without limitation, the dismissal of an action without prejudice, in defense of any action, assertion of a counterclaim (if such counterclaim was approved in advance by the Company), suit, proceeding, inquiry or investigation referred to in Section (1)(a) hereof or in the defense of any claim, assertion of a counterclaim (if such counterclaim was approved in advance by the Company), issue or matter therein, Indemnitee shall be indemnified against all Expenses incurred by Indemnitee in connection therewith.

2. Expenses; Indemnification Procedure.

(a) Advancement of Expenses. The Company shall advance all Expenses incurred by Indemnitee. The advances to be made hereunder shall be paid by the Company to Indemnitee as soon as practicable but in any event no later than five days after written demand by Indemnitee therefor to the Company.

(b) Notice and Cooperation by Indemnitee. Indemnitee shall, as a condition precedent to Indemnitee's right to be indemnified under this Agreement, give the Company notice in writing as soon as practicable of any Claim made against Indemnitee for which indemnification will or could be sought under this Agreement. Notice to the Company shall be directed to the President of the Company at the address shown on the signature page of this Agreement (or such other address as the Company shall designate in writing to Indemnitee). In addition, Indemnitee shall give the Company such information and cooperation as it may reasonably require and as shall be within Indemnitee's power.

(c) No Presumptions; Burden of Proof. For purposes of this Agreement, the termination of any Claim by judgment, order, settlement (whether with or without court approval) or conviction, or upon a plea of nolo contendere, or its equivalent, shall not create a presumption that Indemnitee did not meet any particular standard of conduct or have any particular belief or that a court has determined that indemnification is not permitted by applicable law. In addition, neither the failure of the Reviewing Party to have made a determination as to whether Indemnitee has met any particular standard of conduct or had any particular belief, nor an actual determination by the Reviewing Party that Indemnitee has not met such standard of conduct or did not have such belief, prior to the commencement of legal proceedings by Indemnitee to secure a judicial determination that Indemnitee should be indemnified under applicable law, shall be a defense to Indemnitee's claim or create a presumption that Indemnitee has not met any particular standard of conduct or did not have any particular belief. In connection with any determination by the Reviewing Party or otherwise as to whether Indemnitee is entitled to be indemnified hereunder, the burden of proof shall be on the Company to establish that Indemnitee is not so entitled. The knowledge and/or actions, or failure to act, of any director, manager, officer, agent or employee of the Company or of any subsidiary of the Company shall not be imputed to Indemnitee for purposes of determining the right of indemnification under this Agreement.

(d) Notice to Insurers. If, at the time of the receipt by the Company of a notice of a Claim pursuant to Section 2(b) hereof, the Company has liability insurance in effect which may cover such Claim, the Company shall give prompt notice of the commencement of such Claim to the insurers in accordance with the procedures set forth in the respective policies. The Company shall thereafter take all necessary or desirable action to cause such insurers to pay, on behalf of Indemnitee, all amounts payable as a result of such action, suit, proceeding, inquiry or investigation in accordance with the terms of such policies.

(e) Selection of Counsel. In the event the Company shall be obligated hereunder to pay the Expenses of any Claim, the Company shall be entitled to assume the defense of such Claim with counsel approved by Indemnitee, which approval shall not be unreasonably withheld, upon the delivery to Indemnitee of written notice of its election so to do. After delivery of such notice, approval of such counsel by Indemnitee and the retention of such counsel by the Company, the Company will not be liable to Indemnitee under this Agreement for any fees of counsel subsequently incurred by Indemnitee with respect to the same Claim; provided that, (i) Indemnitee shall have the right to employ Indemnitee's counsel in any such Claim at Indemnitee expense and (ii) if, (A) the employment of counsel by Indemnitee has been previously authorized by the Company, (B) Indemnitee shall have reasonably concluded that there is a conflict of interest between the Company and Indemnitee in the conduct of any such defense, or (C) the Company shall not continue to retain such counsel to defend such Claim, then the fees and expenses of Indemnitee's counsel shall be at the expense of the Company. The Company shall have the right to conduct such defense as it sees fit in its sole discretion, including the right to settle any claim against Indemnitee without the consent of the Indemnitee.

3. Additional Indemnification Rights; Nonexclusivity.

(a) Scope. The Company hereby agrees to indemnify Indemnitee to the fullest extent permitted by law, notwithstanding whether such indemnification is specifically authorized by the other provisions of this Agreement, the Company's Certificate of Incorporation, the Company's Bylaws or by statute. In the event of any change after the date of this Agreement in any applicable law, statute or rule which expands the right of a Delaware corporation to indemnify a member of its Board of Directors, or an officer, employee, agent or fiduciary, as the case may be, it is the intent of the parties hereto that Indemnitee shall enjoy by this Agreement the greater benefits afforded by such change. In the event of any change in any applicable law, statute or rule which narrows the right of a Delaware corporation to indemnify a member of its Board of Directors or an officer, employee, agent or fiduciary, as the case may be, such change, to the extent not otherwise required by such law, statute or rule to be applied to this Agreement, shall have no effect on this Agreement or the parties' rights and obligations hereunder except as set forth in Section 8(a) hereof.

(b) Nonexclusivity. The indemnification provided by this Agreement shall be in addition to any rights to which Indemnitee may be entitled under the Company's Certificate of Formation, the Company's Amended and Restated Limited Liability Company Agreement, or the charter documents of any subsidiary of the Company, in each case as amended, any agreement, any vote of members or disinterested directors, the law of the State of Delaware, or otherwise. The indemnification provided under this Agreement shall continue as to Indemnitee for any action Indemnitee took or did not take while serving in an indemnified capacity even though Indemnitee may have ceased to serve in such capacity.

4. No Duplication of Payments. The Company shall not be liable under this Agreement to make any payment in connection with any Claim made against Indemnitee to the extent Indemnitee has otherwise actually received payment (under any insurance policy, charter documents, or otherwise) of the amounts otherwise indemnifiable hereunder.

5. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the Company for some or a portion of Expenses incurred in connection with any Claim, but not, however, for all of the total amount thereof, the Company shall nevertheless indemnify Indemnitee for the portion of such Expenses to which Indemnitee are entitled.

6. Mutual Acknowledgement. Both the Company and Indemnitee acknowledge that in certain instances, federal law or applicable public policy may prohibit the Company from indemnifying its directors, officers, employees, agents or fiduciaries under this Agreement or otherwise. Indemnitee understands and acknowledges that the Company has undertaken or may be required in the future to undertake with the Securities and Exchange Commission to submit the question of indemnification to a court in certain circumstances for a determination of the Company's right under public policy to indemnify Indemnitee.

7. Liability Insurance. To the extent the Company maintains liability insurance applicable to directors, officers, employees, agents or fiduciaries, Indemnitee shall be covered by such policies in such a manner as to provide Indemnitee the same rights and benefits as are accorded to the most favorably insured of the Company's directors, if Indemnitee is a director; or of the Company's officers, if Indemnitee is not a director of the Company but is an officer; or of the key employees, agents or fiduciaries of the Company, if Indemnitee is not an officer or director but is a key employee, agent or fiduciary.

8. Exceptions. Any other provision herein to the contrary notwithstanding, the Company shall not be obligated pursuant to the terms of this Agreement:

(a) Excluded Action or Omissions. To indemnify Indemnitee for Indemnitee's acts, omissions or transactions from which Indemnitee or the Indemnitee may not be indemnified under applicable law;

(b) Claims Initiated by Indemnitee. To indemnify or advance expenses to Indemnitee with respect to Claims initiated or brought voluntarily by Indemnitee and not by way of defense, except (i) with respect to actions or proceedings brought to establish or enforce a right to indemnification under this Agreement or any other agreement or insurance policy or under the Company's Certificate of Formation or Amended and Restated Limited Liability Company Agreement, now or hereafter in effect relating to Claims for Indemnifiable Events, (ii) in specific cases if the Board of Directors has approved the initiation or bringing of such Claim, or (iii) as otherwise required under Section 18-108 of the Delaware Limited Liability Company Act, regardless of whether Indemnitee ultimately is determined to be entitled to such indemnification, advance expense payment or insurance recovery, as the case may be;

(c) Lack of Good Faith. To indemnify Indemnitee for any expenses incurred by Indemnitee with respect to any proceeding instituted by Indemnitee to enforce or interpret this Agreement, if a court of competent jurisdiction determines that each of the material assertions made by Indemnitee in such proceeding was not made in good faith or was frivolous; or

(d) Claims Under Section 16(b). To indemnify Indemnitee for the payment of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 16(b) of the Securities Exchange Act of 1934, as amended, or any similar successor statute.

9. Period of Limitations. No legal action shall be brought and no cause of action shall be asserted by or in the right of the Company against Indemnitee, Indemnitee's estate, spouse, heirs, executors or personal or legal representatives after the expiration of two years from the date of accrual of such cause of action, and any claim or cause of action of the Company shall be extinguished and deemed released unless asserted by the timely filing of a legal action within such two-year period; provided, however, that if any shorter period of limitations is otherwise applicable to any such cause of action, such shorter period shall govern.

10. Construction of Certain Phrases.

(a) For purposes of this Agreement, references to the "Company" shall include, in addition to the resulting corporation, any constituent corporation or other entity (including any constituent of a constituent) absorbed in a consolidation or merger which, if its separate existence had continued, would have had power and authority to indemnify its directors, managers, partners, officers, employees, agents or fiduciaries, so that if Indemnitee is or was a director, manager, partner officer, employee, agent or fiduciary of such constituent corporation or other entity, or is or was serving at the request of such constituent corporation or other entity as a director, manager, partner officer, employee, agent or fiduciary of another corporation, limited liability company, partnership, limited partnership, joint venture, employee benefit plan, trust or other enterprise, Indemnitee shall stand in the same position under the provisions of this Agreement with respect to the resulting or surviving corporation or other entity as Indemnitee would have with respect to such constituent corporation or other entity if its separate existence had continued.

(b) For purposes of this Agreement, references to "other enterprises" shall include employee benefit plans; references to "fines" shall include any excise taxes assessed on Indemnitee with respect to an employee benefit plan; and references to "serving at the request of the Company" shall include any service as a director, manager, partner, officer, employee, agent or fiduciary of the Company or any subsidiary of the Company which imposes duties on, or involves services by, such director, manager, partner, officer, employee, agent or fiduciary with respect to an employee benefit plan, its participants or its beneficiaries; and if Indemnitee acted in good faith and in a manner Indemnitee reasonably believed to be in the interest of the participants and beneficiaries of an employee benefit plan, Indemnitee shall be deemed to have acted in a manner not opposed to the best interests of the Company.

(c) For purposes of this Agreement, a "Reviewing Party" shall mean any appropriate person or body consisting of a member or members of the Company's Board of Directors or any other person or body appointed by the Board of Directors who is not a party to the particular Claim for which Indemnitee is seeking indemnification.

11. Counterparts. This Agreement may be executed in one or more counterparts, each of which shall constitute an original.

12. Binding Effect; Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of and be enforceable by the parties hereto and their respective successors, assigns, including any direct or indirect successor by purchase, merger, consolidation or otherwise to all or substantially all of the business and/or assets of the Company, spouses, heirs, and personal and legal representatives. The Company shall require and cause any successor (whether direct or indirect by purchase, merger, consolidation or otherwise) to all, substantially all, or a substantial part, of the business and/or assets of the Company, by written agreement in form and substance satisfactory to Indemnitee, expressly to assume and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place. This Agreement shall continue in effect with respect to Claims relating to Indemnifiable Events regardless of whether Indemnitee continues to serve as a director, manager, partner, officer, employee, agent or fiduciary of the Company, any of its subsidiaries or of any other enterprise at the Company's request.

13. Attorneys' Fees. In the event that any action is instituted by Indemnitee under this Agreement or under any liability insurance policies maintained by the Company to enforce or interpret any of the terms hereof or thereof, Indemnitee shall be entitled to be paid all Expenses incurred by Indemnitee with respect to such action, regardless of whether Indemnitee is ultimately successful in such action, and shall be entitled to the advancement of Expenses with respect to such action, unless, as a part of such action, a court of competent jurisdiction over such action determines that each of the material assertions made by Indemnitee as a basis for such action was not made in good faith or was frivolous. In the event of an action instituted by or in the name of the Company under this Agreement to enforce or interpret any of the terms of this Agreement, Indemnitee shall be entitled to be paid all Expenses incurred by Indemnitee in defense of such action (including costs and expenses incurred with respect to Indemnitee counterclaims and cross-claims made in such action), and shall be entitled to the advancement of Expenses with respect to such action, unless, as a part of such action, a court having jurisdiction over such action determines that each of Indemnitee's material defenses to such action was made in bad faith or was frivolous.

14. Notice. All notices and other communications required or permitted hereunder shall be in writing, shall be effective when given, and shall in any event be deemed to be given (a) five days after deposit with the U.S. Postal Service or other applicable postal service, if delivered by first class mail, postage prepaid, (b) upon delivery, if delivered by hand, (c) one business day after the business day of deposit with Federal Express or similar overnight courier, freight prepaid, or (d) upon sending, with delivery receipt requested, if delivered by email, with a hard copy by first class mail, postage prepaid, Federal Express or similar overnight courier, and shall be addressed if to Indemnitee, at the Indemnitee address as set forth beneath Indemnitee's signature to this Agreement and if to the Company at the address of its principal corporate offices (attention: General Counsel) or at such other address as such party may designate by ten days' advance written notice to the other party hereto.

15. Consent to Jurisdiction. The Company and Indemnitee each hereby irrevocably consent to the jurisdiction of the courts of the State of Delaware for all purposes in connection with any action or proceeding which arises out of or relates to this Agreement and agree that any action instituted under this Agreement shall be commenced, prosecuted and continued only in the Court of Chancery of the State of Delaware in and for New Castle County, which shall be the exclusive and only proper forum for adjudicating such a claim.

16. Severability. The provisions of this Agreement shall be severable in the event that any of the provisions hereof (including any provision within a single section, paragraph or sentence) are held by a court of competent jurisdiction to be invalid, void or otherwise unenforceable, and the remaining provisions shall remain enforceable to the fullest extent permitted by law. Furthermore, to the fullest extent possible, the provisions of this Agreement (including, without limitations, each portion of this Agreement containing any provision held to be invalid, void or otherwise unenforceable, that is not itself invalid, void or unenforceable) shall be construed so as to give effect to the intent manifested by the provision held invalid, illegal or unenforceable.

17. Choice of Law. This Agreement shall be governed by and its provisions construed and enforced in accordance with the laws of the State of Delaware, as applied to contracts between Delaware residents, entered into and to be performed entirely within the State of Delaware, without regard to the conflict of laws principles thereof.

18. Subrogation. In the event of payment under this Agreement, the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee who shall execute all documents required and shall do all acts that may be necessary to secure such rights and to enable the Company effectively to bring suit to enforce such rights.

19. Amendment and Termination. No amendment, modification, termination or cancellation of this Agreement shall be effective unless it is in writing signed by both the parties hereto. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provisions hereof (whether or not similar) nor shall such waiver constitute a continuing waiver.

20. Integration and Entire Agreement. This Agreement sets forth the entire understanding between the parties hereto and supersedes and merges all previous written and oral negotiations, commitments, understandings and agreements relating to the subject matter hereof between the parties hereto.

21. No Construction as Employment Agreement. Nothing contained in this Agreement shall be construed as giving Indemnitee any right to be retained in the employ of the Company or any of its subsidiaries.

[signature page follows immediately hereafter]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first above written.

Midcoast Holdings, L.L.C.

____

By: C. Gregory Harper
Title: President
Address: 1100 Louisiana St., Suite 3300
Houston, TX 77002

AGREED TO AND ACCEPTED BY:

Signature: ______________________________
Name:

SCHEDULE OF OMITTED AGREEMENTS

The following Indemnification Agreements have not been filed as exhibits pursuant to Instruction 2 of Item 601 of Regulation S-K. These documents are substantially identical in all material respects to Exhibit 10.6 to this Form 10-Q.

1. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Janet L. Coy.
2. Indemnification Agreement, dated effective as of February 10, 2014, by and between Midcoast Holdings, L.L.C. and John A. Crum.
3. Indemnification Agreement, dated effective as of October 10, 2013, by and between Midcoast Holdings, L.L.C. and J. Herbert England.
4. Indemnification Agreement, dated effective as of January 30, 2014, by and between Midcoast Holdings L.L.C. and C. Gregory Harper.
5. Indemnification Agreement, dated effective as of February 10, 2014, by and between Midcoast Holdings, L.L.C. and James G. Ivey.
6. Indemnification Agreement, dated effective as of July 29, 2013, by and between Midcoast Holdings, L.L.C. and Noor S. Kaissi.
7. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and E. Chris Kaitson.
8. Indemnification Agreement, dated effective as of October 14, 2013, by and between Midcoast Holdings, L.L.C. and Kenneth C. Lanik.
9. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and John A. Loiacono.
10. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Mark A. Maki.
11. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Byron C. Neiles.
12. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Stephen J. Neyland.
13. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Kerry C. Puckett.
14. Indemnification Agreement, dated effective as of March 14, 2014, by and between Midcoast Holdings, L.L.C. and Jonathan N. Rose.
15. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Allan M. Schneider.
16. Indemnification Agreement, dated effective as of February 10, 2014, by and between Midcoast Holdings, L.L.C. and Edmund P. Segner, III.
17. Indemnification Agreement, dated effective as of May 31, 2013, by and between Midcoast Holdings, L.L.C. and Bruce A. Stevenson.
18. Indemnification Agreement, dated effective as of December 20, 2013, by and between Midcoast Holdings, L.L.C. and Valorie J. Wanner.
19. Indemnification Agreement, dated effective as of July 30, 2014, by and between Midcoast Holdings, L.L.C. and David A. Weathers.
20. Indemnification Agreement, dated effective as of October 10, 2013, by and between Midcoast Holdings, L.L.C. and Dan A. Westbrook.
21. Indemnification Agreement, dated effective as of May 29, 2014, by and between Midcoast Holdings, L.L.C. and Thomas J. Zimmerman.
22. Indemnification Agreement, dated effective as of September 28, 2015, by and between Midcoast Holdings, L.L.C. and R. Poe Reed.

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 30, 2015

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 30, 2015

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, 2015 (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 30, 2015

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, 2015 (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 30, 2015

By: /s/ Stephen J. Neyland

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