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 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**39-1715850**
(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 262,208,428 Class A common units outstanding as of October 30, 2015.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our," "EEP" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our "General Partner." References to "Enbridge" refer collectively to Enbridge Inc., and its subsidiaries other than us. References to "Enbridge Management" refer to Enbridge Energy Management, L.L.C., the delegate of our General Partner that manages our business and affairs.

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 crude oil, liquid petroleum, natural gas and natural gas liquids, or NGLs, including the rate of development of the Alberta Oil Sands; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline systems; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to which we sell products; (5) hazards and operating risks that may not be covered fully by insurance, including those related to Line 6B and any additional fines and penalties assessed in connection with the crude oil release on that line; (6) changes in or challenges to our tariff rates, (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance; and (8) permitting at federal, state and local levels in regards to the construction of new assets.

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 SEC's, website (www.sec.gov) and at our website (www.enbridgepartners.com).

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE 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:				
Commodity sales (Note 12)	$ 597.7	$1,296.4	$2,101.3	$4,114.2
Commodity sales – affiliate (Notes 10 and 12)	12.2	50.6	62.4	174.7
Transportation and other services (Note 12)	621.4	577.6	1,744.6	1,549.4
Transportation and other services – affiliate (Note 10)	36.4	17.7	101.1	54.7
	1,267.7	1,942.3	4,009.4	5,893.0
Operating expenses:				
Commodity costs (Notes 5 and 12)	503.3	1,208.5	1,912.0	3,888.4
Commodity costs – affiliate (Note 10)	19.4	29.7	60.4	98.3
Environmental costs, net of recoveries (Note 11)	1.1	50.1	1.1	93.3
Operating and administrative (Notes 6 and 11)	163.3	119.4	353.0	323.3
Operating and administrative – affiliate (Note 10)	117.3	115.9	351.9	353.6
Power (Note 12)	71.6	59.5	192.4	164.1
Depreciation and amortization (Note 6)	136.9	118.8	394.8	336.0
Goodwill impairment (Note 7)	—	—	246.7	—
Asset impairment (Note 6)	—	—	12.3	—
	1,012.9	1,701.9	3,524.6	5,257.0
Operating income	254.8	240.4	484.8	636.0
Interest expense, net (Notes 8 and 12)	(88.2)	(137.1)	(214.5)	(294.2)
Allowance for equity used during construction (Note 16)	13.7	14.5	54.0	47.8
Other income (Note 10)	8.8	1.8	20.7	2.2
Income before income tax expense	189.1	119.6	345.0	391.8
Income tax expense (Note 13)	(4.6)	(2.1)	(3.2)	(6.1)
Net income	184.5	117.5	341.8	385.7
Less: Net income attributable to:				
Noncontrolling interest (Note 10)	77.8	70.7	139.1	149.4
Series 1 preferred unit distributions	22.5	22.5	67.5	67.5
Accretion of discount on Series 1 preferred units	2.1	3.8	10.1	11.1
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 82.1	$ 20.5	$ 125.1	$ 157.7
Net income (loss) allocable to common units and i-units	$ 26.1	$ (14.5)	$ (37.4)	$ 49.5
Net income (loss) per common unit and i-unit (basic and diluted) (Note 2)	$ 0.07	$ (0.04)	$ (0.11)	$ 0.15
Weighted average common units and i-units outstanding (basic and diluted)	341.1	328.8	337.9	327.6

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

ENBRIDGE 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	$ 184.5	$117.5	$ 341.8	$385.7
Other comprehensive income (loss), net of tax expense (Note 12)	(131.0)	55.5	(181.2)	(80.6)
Comprehensive income	53.5	173.0	160.6	305.1
Less:				
Net income attributable to noncontrolling interest (Note 10)	77.8	70.7	139.1	149.4
Net income attributable to Series 1 preferred unit distributions	22.5	22.5	67.5	67.5
Net income attributable to accretion of discount on Series 1 preferred units	2.1	3.8	10.1	11.1
Other comprehensive income (loss) allocated to noncontrolling interest	(1.3)	2.1	(3.9)	1.8
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (47.6)	$ 73.9	$ (52.2)	$ 75.3

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the nine months ended September 30,	
	2015	2014
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 341.8	$ 385.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	394.8	336.0
Derivative fair value net losses (Note 12)	40.0	62.7
Inventory market price adjustments (Note 5)	5.4	4.8
Goodwill impairment (Note 7)	246.7	—
Environmental costs, net of recoveries (Note 11)	0.7	81.5
Distributions from investments in joint ventures (Note 10)	20.5	6.1
Equity earnings from investments in joint ventures (Note 10)	(20.5)	(7.1)
Income taxes (Note 13)	2.1	4.7
Loss on sales of assets	3.2	—
Allowance for equity used during construction (Note 16)	(54.0)	(47.8)
Asset impairment (Note 6)	12.3	—
Other	7.7	13.0
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	36.2	0.9
Due from General Partner and affiliates	(28.1)	15.3
Accrued receivables	216.2	27.7
Inventory (Note 5)	0.5	(131.0)
Current and long-term other assets (Note 12)	(33.6)	(28.7)
Due to General Partner and affiliates	80.5	(23.4)
Accounts payable and other (Notes 4 and 12)	(11.5)	(93.1)
Environmental liabilities (Note 11)	(34.5)	(116.7)
Accrued purchases	(175.1)	(28.6)
Interest payable	0.3	5.9
Property and other taxes payable	2.7	23.8
Net cash provided by operating activities	1,054.3	491.7
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 6 and 15)	(1,556.2)	(2,055.8)
Acquisitions (Note 3)	(85.0)	—
Changes in restricted cash (Note 10)	65.8	31.2
Proceeds from sales of assets	5.3	—
Investments in joint ventures (Note 10)	(3.0)	(35.4)
Distributions from investments in joint ventures in excess of cumulative earnings	9.5	27.0
Other	(2.9)	(0.7)
Net cash used in investing activities	(1,566.5)	(2,033.7)
Cash provided by financing activities:		
Net proceeds from unit issuances (Note 9)	294.8	—
Distributions to partners (Note 9)	(619.9)	(544.2)
Repayments to General Partner (Note 10)	(306.0)	(12.0)
Proceeds from issuance of long-term debt, net of discounts (Note 8)	—	398.1
Net borrowings (repayments) under credit facilities (Note 8)	785.0	30.0
Net commercial paper borrowings (repayments) (Note 8)	(291.0)	799.8
Contributions from noncontrolling interest (Notes 9 and 10)	740.6	1,083.0
Distributions to noncontrolling interest (Notes 9 and 10)	(178.7)	(80.9)
Net cash provided by financing activities	424.8	1,673.8
Net increase (decrease) in cash and cash equivalents	(87.4)	131.8
Cash and cash equivalents at beginning of year	197.9	164.8
Cash and cash equivalents at end of period	$ 110.5	$ 296.6

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

ENBRIDGE 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 4)	$ 110.5	$ 197.9
Restricted cash (Notes 3, 10 and 12)	46.2	97.0
Receivables, trade and other, net of allowance for doubtful accounts of $1.6 million and $1.8 million at September 30, 2015 and December 31, 2014, respectively	9.8	46.2
Due from General Partner and affiliates	69.9	41.4
Accrued receivables	44.1	260.3
Inventory (Note 5)	88.3	94.2
Other current assets (Note 12)	193.8	218.4
	562.6	955.4
Property, plant and equipment, net (Notes 6 and 16)	17,006.4	15,692.7
Goodwill (Note 7)	—	246.7
Intangible assets, net	284.3	254.8
Other assets, net (Note 12)	553.6	597.3
	$18,406.9	$17,746.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 10)	$ 225.4	$ 143.7
Accounts payable and other (Notes 4, 12 and 16)	903.5	777.7
Environmental liabilities (Note 11)	101.6	141.7
Accrued purchases	200.6	375.7
Interest payable	74.7	74.6
Property and other taxes payable (Note 13)	99.2	96.5
Note payable to General Partner (Note 10)	—	306.0
	1,605.0	1,915.9
Long-term debt (Note 8)	7,169.8	6,675.2
Due to General Partner and affiliates (Note 10)	215.8	148.3
Other long-term liabilities (Notes 6, 11, 12 and 13)	357.0	278.1
	9,347.6	9,017.5
Commitments and contingencies (Note 11)		
Partners' capital: (Notes 9 and 10)		
Series 1 preferred units (48,000,000 authorized and issued at September 30, 2015 and December 31, 2014)	1,185.7	1,175.6
Class D units (66,100,000 authorized and issued at September 30, 2015 and December 31, 2014)	2,517.6	2,516.8
Class E units (18,114,975 authorized and issued at September 30, 2015)	778.3	—
Class A common units (262,208,428 and 254,208,428 authorized and issued at September 30, 2015 and December 31, 2014, respectively)	—	235.5
Class B common units (7,825,500 authorized and issued at September 30, 2015 and December 31, 2014)	—	—
i-units (71,742,557 and 68,305,187 authorized and issued at September 30, 2015 and December 31, 2014, respectively)	399.6	712.6
Incentive distribution units (1,000 authorized and issued at September 30, 2015 and December 31, 2014)	494.9	493.0
General Partner	169.5	198.3
Accumulated other comprehensive loss (Note 12)	(388.7)	(211.4)
Total Enbridge Energy Partners, L.P. partners' capital	5,156.9	5,120.4
Noncontrolling interest (Note 10)	3,902.4	3,609.0
Total partners' capital	9,059.3	8,729.4
	$18,406.9	$17,746.9

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

1. 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 crude oil, seasonality of portions of our natural gas business, 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 and the effect of environmental costs and related insurance recoveries on our Lakehead system. 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 UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, our General Partner interest and our limited partner units using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income attributable to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We allocate our net income to our limited partners owning Class D units and Class E units equal to the distributions that they receive. We also allocate any earnings in excess of distributions to our General Partner and limited partners owning Class A and Class B common units and i-units utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners owning Class A and B common units and i-units based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement. We calculate distributions to the General Partner and limited partners based upon the distribution rates and percentages set forth in the following table:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner and IDUs[(1)]	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to \$0.5435	2%	98%
First Target Distribution	> \$0.5435	25%	75%

(1) For distributions in excess of the Minimum Quarterly Distribution, this percentage includes both the General Partner's distributions of 2% and the distribution to the Incentive Distribution Unit holder, a wholly-owned subsidiary of our General Partner.

Equity Restructuring Transaction

On July 1, 2014, we entered into an equity restructuring transaction, or Equity Restructuring, with the General Partner in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction and loss in excess of 2% in respect of its general partner interest in the incentive distribution rights, or Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (1) 66.1 million units of a new class of limited partner interests designated as Class D units, and (2) 1,000 units of a new class of limited partner interests designated as Incentive Distribution Units, or IDUs. Prior to this transaction we allocated distributions to the General Partner and limited partners as follows:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to \$0.295	2%	98%
First Target Distribution	> \$0.295 to \$0.35	15%	85%
Second Target Distribution	> \$0.35 to \$0.495	25%	75%
Over Second Target Distribution	In excess of \$0.495	50%	50%

2. NET INCOME PER LIMITED PARTNER UNIT – (continued)

Alberta Clipper Drop Down

On January 2, 2015, we completed a transaction to acquire from our General Partner the remaining 66.7% interest in the U.S. portion of the Alberta Clipper Pipeline. The consideration consisted of issuance to the General Partner of 18,114,975 units of a new class of limited partner interests designated as Class E units. For more information, refer to Note 9. *Partners' Capital*.

We determined basic and diluted net income 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	$ 184.5	$ 117.5	$ 341.8	$ 385.7
Less Net loss attributable to:				
Noncontrolling interest	(77.8)	(70.7)	(139.1)	(149.4)
Series 1 preferred unit distributions	(22.5)	(22.5)	(67.5)	(67.5)
Accretion of discount on Series 1 preferred units	(2.1)	(3.8)	(10.1)	(11.1)
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	82.1	20.5	125.1	157.7
Less distributions:				
Incentive distributions	(5.3)	(1.4)	(13.8)	(35.9)
Distributed earnings attributed to our General Partner	(5.1)	(4.5)	(15.3)	(12.6)
Distributed earnings attributed to Class D and Class E units	(49.1)	(33.1)	(146.2)	(69.8)
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(59.5)	(39.0)	(175.3)	(118.3)
Total distributed earnings attributed to our common units and i-units	(199.2)	(182.8)	(591.2)	(542.7)
Total distributed earnings	(258.7)	(221.8)	(766.5)	(661.0)
Overdistributed earnings	$(176.6)	$(201.3)	$(641.4)	$(503.3)
Weighted average common units and i-units outstanding	341.1	328.8	337.9	327.6
Basic and diluted earnings per unit:				
Distributed earnings per common unit and i-unit[(1)]	$ 0.58	$ 0.56	$ 1.75	$ 1.66
Overdistributed earnings per common unit and i-unit[(2)]	(0.51)	(0.60)	(1.86)	(1.51)
Net income (loss) per common unit and i-unit (basic and diluted)[(3)]	$ 0.07	$ (0.04)	$ (0.11)	$ 0.15

(1) Represents the total distributed earnings to common units and i-units divided by the weighted average number of common units and i-units outstanding for the period.

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

(3) For the three and nine months ended September 30, 2015, 43,201,310 anti-dilutive Preferred units, 66,100,000 anti-dilutive Class D units and 18,114,975 anti-dilutive Class E units were excluded from the if-converted method of calculating diluted earnings per unit. For the three months ended September 30, 2014, 43,201,310 anti-dilutive Preferred units and 66,100,000 anti-dilutive Class D units were excluded from the if-converted method of calculating diluted earnings per unit. For the nine months ended September 30, 2014, 43,201,310 anti-dilutive Preferred units and 22,275,458 anti-dilutive Class D units were excluded from the if-converted method of calculating diluted earnings per unit.

3. 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, Midcoast Energy Partners, L.P., or MEP, 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 MEP's position into the Eaglebine play, and will continue to allow them to offer gathering and processing services while leveraging assets on their existing footprint.

MEP acquired NGR's midstream business for $85.0 million in cash and a contingent future payment of up to $17.0 million. Of the $85.0 million purchase price, $20.0 million was placed into escrow, pending the resolution of a legal matter and NGR's completion of additional wells connecting to our system. Since the acquisition date, MEP has 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, MEP will be obligated to make future tiered payments up to $17.0 million. This could result in a maximum total purchase 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 statements of financial position.

Funding was provided by us and MEP, based on our proportionate ownership percentages in Midcoast Operating, L.P., or Midcoast Operating, at the time of acquisition, which was 48.4% and 51.6%, respectively. This business is part of our Natural Gas segment.

4. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $16.9 million at September 30, 2015, and $17.9 million at December 31, 2014, are included in ''Accounts payable and other'' on our consolidated statements of financial position. At December 31, 2014, we reclassified book overdrafts of $40.0 million to ''Accounts payable and other'' on our consolidated statement of financial position. We did not have any book overdrafts at September 30, 2015.

5. INVENTORY

Our inventory is comprised of the following:

	September 30, 2015	December 31, 2014
	(in millions)	
Materials and supplies	$ 2.2	$ 2.2
Crude oil inventory	0.8	13.2
Natural gas and NGL inventory	85.3	78.8
	$88.3	$94.2

''Commodity costs'' on our consolidated statements of income include 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.

6. PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2015	December 31, 2014
	(in millions)	
Land	$ 60.4	$ 44.2
Rights-of-way	869.7	851.8
Pipelines	9,788.9	9,585.4
Pumping equipment, buildings and tanks[(1)]	4,092.5	3,261.8
Compressors, meters and other operating equipment	2,145.6	2,072.7
Vehicles, office furniture and equipment[(1)]	280.7	278.9
Processing and treating plants	632.8	516.0
Construction in progress	2,250.4	1,857.1
Total property, plant and equipment	20,121.0	18,467.9
Accumulated depreciation	(3,114.6)	(2,775.2)
Property, plant and equipment, net	$17,006.4	$15,692.7

(1) During the second quarter 2015, management reclassified $135.0 million related to rail facilities from "Vehicles, office furniture and equipment" to "Pumping equipment, buildings, and tanks" to better reflect the way in which these assets are analyzed. This change has been retrospectively adjusted for all periods presented.

On July 31, 2015, MEP sold its non-core Tinsley crude oil pipeline, storage facilities, and docks and its non-core Louisiana propylene pipeline for $1.3 million. These assets are part of our Natural Gas segment and had a combined carrying value 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 administrative" 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.

7. 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 that are fully associated with our natural gas business. The carrying amount of goodwill as of December 31, 2014, was $246.7 million.

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 the natural gas reporting unit 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 natural gas reporting unit exceeded its fair value. We completed the second step of the goodwill impairment analysis comparing the implied fair value of the reporting unit to the carrying amount of that goodwill, using amounts as of June 30, 2015, and determined that goodwill was completely impaired in the amount of $246.7 million. The impairment charge 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 natural gas reporting unit.

8. DEBT

The following table presents the primary components of our outstanding indebtedness with third parties and the weighted average interest rates associated with each component as of September 30, 2015, before the effect of our interest rate hedging activities. Our indebtedness with related parties is discussed in Note 10. *Related Party Transactions.*

	Interest Rate	September 30, 2015	December 31, 2014
		(in millions)	
EEP debt obligations:			
Commercial Paper[1]	1.000%	$ 321.1	$ 612.3
Credit Facilities due 2016 – 2019	1.30% – 3.75%	1,885.0	1,160.0
Senior Notes due December 2016	5.875%	300.0	300.0
Senior Notes due October 2018	7.000%	100.0	100.0
Senior Notes due April 2018	6.500%	400.0	400.0
Senior Notes due March 2019	9.875%	500.0	500.0
Senior Notes due March 2020	5.200%	500.0	500.0
Senior Notes due September 2021	4.200%	600.0	600.0
Senior Notes due October 2028	7.125%	100.0	100.0
Senior Notes due June 2033	5.950%	200.0	200.0
Senior Notes due December 2034	6.300%	100.0	100.0
Senior Notes due April 2038	7.500%	400.0	400.0
Senior Notes due September 2040	5.500%	550.0	550.0
Junior subordinated notes due 2067	8.050%	400.0	400.0
MEP debt obligations:			
MEP Credit Agreement due 2016 – 2018	2.672%	420.0	360.0
MEP Series A Senior Notes due September 2019	3.560%	75.0	75.0
MEP Series B Senior Notes due September 2021	4.040%	175.0	175.0
MEP Series C Senior Notes due September 2024	4.420%	150.0	150.0
Total Principal of Debt Obligations		7,176.1	6,682.3
Other:			
Unamortized Discount		(6.3)	(7.1)
Total Long Term Debt		$7,169.8	$6,675.2

(1) Individual issuances of commercial paper generally mature in 90 days or less, but are supported by our Credit Facilities and are therefore considered long-term debt.

Interest Cost

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, 2015	For the three months ended September 30, 2014	For the nine months ended September 30, 2015	For the nine months ended September 30, 2014
	(in millions)			
Interest cost incurred	$98.8	$148.7	$243.4	$329.9
Less: Interest capitalized	10.6	11.6	28.9	35.7
Interest expense	$88.2	$137.1	$214.5	$294.2

8. DEBT – (continued)

Credit Facilities and Commercial Paper

We have a committed multi-year senior unsecured revolving credit facility, which we refer to as the Credit Facility, and a 364-day credit agreement, which we refer to as the 364-Day Credit Facility. We refer to our Credit Facility and our 364-Day Credit Facility as the Credit Facilities. The Credit Facility permits aggregate borrowings of up to, at any one time outstanding, $1.975 billion. The maturity date on the Credit Facility is September 26, 2019; except for, $175.0 million of commitments will expire on the original maturity date of September 26, 2018. At September 30, 2015, we had $1,885.0 million outstanding under our Credit Facilities at a weighted average interest rate of 2.13%. During the nine months ended September 30, 2015, we had net borrowings of $725.0 million, which includes gross borrowings of $12,285.0 million and gross repayments of $11,560.0 million.

On July 2, 2015, we amended our 364-Day Credit Facility to extend the revolving credit termination date from July 3, 2015 to July 1, 2016. We further amended the 364-Day Credit Facility to decrease the aggregate commitments from $650.0 million to $525.0 million: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion, and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods. On August 7, 2015, we exercised our right to increase the total amount of commitments under the 364-Day Credit Facility by $100.0 million to $625.0 million.

At September 30, 2015, the Credit Facilities provide an aggregate amount of approximately $2.6 billion of bank credit, which we use to fund our general activities and working capital needs.

In addition, we have a credit agreement with Enbridge (U.S.) Inc., or EUS, an affiliate of Enbridge and the owner of our General Partner, or the EUS 364-day Credit Facility, that permits aggregate borrowing of up to, at any one time outstanding, $750.0 million, which is discussed in Note 10. *Related Party Transactions*.

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At September 30, 2015, we had approximately $321.1 million in principal amount of commercial paper outstanding at a weighted average interest rate of 1.00%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately $291.0 million during the nine months ended September 30, 2015, which includes gross borrowings of $8,436.1 million and gross repayments of $8,727.1 million. At December 31, 2014, we had approximately $612.3 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.50%, excluding the effect of our interest rate hedging activities. Our policy is to limit the amount of commercial paper we can issue by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion.

We have an uncommitted letter of credit arrangement, pursuant to which the lender may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request. The aggregate amount of this uncommitted letter of credit is not to exceed $220.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the lender's sole discretion, we view this arrangement as a liquidity enhancement as it allows us to potentially reduce our reliance on utilizing our committed Credit Facilities for issuance of letters of credit to support our hedging activities.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. Our policy is to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at any time.

8. DEBT – (continued)

At September 30, 2015, we had approximately $724.6 million available under the terms of our Credit Facilities and the EUS 364-day Credit Facility, determined as follows:

	(in millions)
Total credit available under our Credit Facilities	$2,600.0
Total credit available under the EUS 364-day Credit Facility	750.0
Less: Amounts outstanding under our Credit Facilities	1,885.0
Principal amount of commercial paper outstanding	321.1
EUS 364-day Credit Facility[1]	—
Letters of credit outstanding	419.3
Total amount available at September 30, 2015[2]	$ 724.6

(1) Refer to Note 10. *Related Party Transactions* for further details regarding the EUS 364-day Credit Facility.

(2) On October 6, 2015, we closed a public offering of senior unsecured notes, for net aggregate proceeds of approximately $1.26 billion, after deducting underwriting discounts and commissions and estimated offering expenses and settlement of pre-issuance hedges. We used a portion of the net proceeds from this offering to repay a portion of our outstanding commercial paper and to repay any credit facility borrowings that were outstanding. After the offering on a pro-forma basis the total amount available under the Credit Facilities and the EUS-364 day Credit Facility, less amounts outstanding, is approximately $2.0 billion.

As of September 30, 2015, we were in compliance with the terms of all of our financial covenants under our Credit Facilities and the EUS 364-day Credit Facility.

MEP Credit Agreement

MEP, Midcoast Operating, and their material domestic subsidiaries are party to a senior revolving credit facility, which we refer to as the MEP Credit Agreement, which previously permitted aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the MEP 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, MEP amended the MEP Credit Agreement and decreased the aggregate commitments to $810.0 million and to extend the maturity date from September 30, 2017 to September 30, 2018; except for, $140.0 million of commitments will expire on the initial maturity date of November 13, 2016 and $25 million of commitments that will expire on September 30, 2017.

At September 30, 2015, MEP had $420.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 2.7%. Under the MEP Credit Agreement, MEP 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. As of September 30, 2015, MEP was in compliance with the terms of its financial covenants.

MEP Senior Notes

MEP's 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, MEP was in compliance with the terms of its financial covenants under the note purchase agreement.

Fair Value of Debt Obligations

The carrying amounts of our outstanding commercial paper, borrowings under our Credit Facilities, and the MEP Credit Agreement approximate their fair values 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 fair value of our outstanding commercial paper and borrowings under our Credit Facilities and the MEP 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.

8. DEBT – (continued)

The approximate fair value of our fixed-rate debt obligations was $4.7 billion and $5.1 billion at September 30, 2015, and December 31, 2014, respectively. 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.

9. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management, or Enbridge Management, during the nine months ended September 30, 2015.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(1)]	Retained from General Partner[(2)]	Distribution of Cash
				(in millions, except per unit amounts)			
July 30, 2015	August 7, 2015	August 14, 2015	$0.5830	$257.9	$41.0	$0.8	$216.1
April 30, 2015	May 8, 2015	May 15, 2015	$0.5700	$249.9	$39.5	$0.8	$209.6
January 29, 2015	February 6, 2015	February 13, 2015	$0.5700	$233.9	$38.9	$0.8	$194.2

(1) We issued 3,437,370 i-units to Enbridge Management, the sole owner of our i-units, during 2015 in lieu of cash distributions.

(2) We retained an amount equal to 2% of the i-unit distribution from our General Partner to maintain its 2% general partner interest in us.

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 interests in our consolidated subsidiaries, Enbridge Energy, Limited Partnership, or OLP, the North Dakota Pipeline Company LLC, or NDPC, and MEP, for the nine months ended September 30, 2015 and 2014. The noncontrolling interest in the OLP arises from the joint funding arrangements with our General Partner and its affiliate to finance: (1) expansion of our Lakehead system to transport crude oil to destinations in the Midwest United States, which we refer to as the Eastern Access Projects; and (2) further expansion of our Lakehead system to transport crude oil between Neche, North Dakota and Superior, Wisconsin, which we refer to as the Mainline Expansion Projects. Noncontrolling interest in NDPC arises from our agreement with Williston Basin Pipeline LLC, or Williston, an affiliate of Marathon Petroleum Corporation, to, among other things, become a member of NDPC. Williston funds 37.5% of the Sandpiper Project that will expand the North Dakota feeder system to Superior, Wisconsin mainline system terminal. Noncontrolling interest in MEP arises from its public unitholders' ownership interests in MEP.

9. PARTNERS' CAPITAL – (continued)

	For the nine months ended September 30,	
	2015	2014
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,175.6	$1,160.7
Net income	67.5	67.5
Accretion of discount on preferred units	10.1	11.1
Distribution payable	(67.5)	(67.5)
Ending balance	$1,185.7	$1,171.8
General and limited partner interests		
Beginning balance	$4,156.2	$4,637.7
Proceeds from issuance of partnership interests, net of costs	294.8	—
Net income	125.1	157.7
Distributions	(619.9)	(544.2)
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	—	(125.4)
Acquisition of noncontrolling interest in subsidiary	403.7	
Ending balance	$4,359.9	$4,125.8
Accumulated other comprehensive loss		
Beginning balance	$ (211.4)	$ (76.6)
Changes in fair value of derivative financial instruments reclassified to earnings	(6.4)	22.2
Changes in fair value of derivative financial instruments recognized in other comprehensive loss	(170.9)	(104.6)
Ending balance	$ (388.7)	$ (159.0)
Noncontrolling interest		
Beginning balance	$3,609.0	$1,975.6
Capital contributions	740.6	1,083.0
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	—	125.4
Acquisition of noncontrolling interest in subsidiary	(403.7)	—
Other comprehensive income (loss) allocated to noncontrolling interest	(3.9)	1.8
Net income	139.1	149.4
Distributions to noncontrolling interest	(178.7)	(80.9)
Ending balance	$3,902.4	$3,254.3
Total partners' capital at end of period	$9,059.3	$8,392.9

Series 1 Preferred Unit Amendment

On July 30, 2015, we amended our limited partnership agreement to extend the deferral of distribution payments through June 30, 2018 and to allow repayment of the accumulated deferral amount in equal amounts over a twelve-quarter period beginning in the first quarter of 2019. In addition, the amendment extended the rate reset pricing date to June 30, 2020, and each subsequent five-year anniversary thereafter. The amendment also defers the conversion option date, whereby the holder of the preferred units may convert their Series 1 preferred units into Class A common units, to on or after June 30, 2018.

The amendment to the Series 1 Preferred Unit was accounted for as a modification, as the difference in the fair value of the preferred units before and after the modification was insignificant. As a result, there were no changes in the partnership capital accounts as a result of the amendment. The remaining unamortized beneficial conversion feature after the amendment will be amortized over an extended period through June 30, 2018.

9. PARTNERS' CAPITAL – (continued)

Alberta Clipper Drop Down

On January 2, 2015, we completed a transaction, or the Drop Down, pursuant to which we acquired the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline from our General Partner. The consideration consisted of approximately 18,114,975 units of a new class of limited partner interests designated as Class E units issued to the General Partner. The Class E units were issued at a notional value of $38.31 per unit. The notional value was determined based on the trailing five-day volume-weighted average price of our Class A common units as of December 23, 2014, which was the date on which we and the General Partner entered into a contribution agreement setting forth the terms of the Drop Down. In addition, we repaid the borrowings outstanding of $306.0 million on the A1 Term Note owed to the General Partner.

The Class E units are entitled to the same distributions as Class A common units held by the public and are convertible into Class A common units on a one-for-one basis at the General Partner's option. The Class E units were not entitled to distributions with respect to the quarter ended December 31, 2014. The Class E units are redeemable at our option after 30 years, if not earlier converted by the General Partner.

The Class E units have a liquidation preference equal to their notional value of $38.31 per unit. If the aggregate Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, attributable to the Series AC interest in the OLP for calendar years 2015 and 2016 is less than $265.9 million, then 1,305,142 of the Class E units will be cancelled by us effective as of June 15, 2017, for no consideration and will no longer be deemed outstanding for any purposes under our partnership agreement.

In addition, during each taxable year during the period from January 1, 2015 through December 31, 2037 in which a majority of the Class E units issued on the closing date of the Drop Down remain outstanding, holders of Class A common units, Class B common units and Class D units (including those held by the General Partner) will be specially allocated items of gross income that would otherwise be allocated to holders of Class E units, to the extent that such an amount of gross income exists, in an annual amount equal to $40.0 million. The annual amount of such allocation will be reduced to $20.0 million for each taxable year beginning after December 31, 2037.

We recorded the Drop Down as an equity transaction. No loss on the acquisition of the remaining ownership interests in Alberta Clipper was recognized in our consolidated statement of income or comprehensive income. We reduced the carrying value of the related "Noncontrolling interest" in Alberta Clipper of $403.7 million to zero. In addition, we recorded the Class E units at their fair value of $767.7 million. We determined the fair value of the Class E units using a market approach based upon the closing price of the Class A common units as of January 2, 2015, adjusted for differences in specific rights such as the liquidation preference granted to the Class E units and other economic factors that would affect the fair value of the Class E units.

The difference of $364.0 million between the fair value of the Class E units and the carrying value of the noncontrolling interest in Alberta Clipper was recorded as a reduction to the carrying amounts of the capital accounts of the Class A and Class B common units, the i-units and the General Partner interest on a pro rata basis. The recording of this transaction reduced the carrying values of the Class A and Class B common units below zero. Our partnership agreement requires that such capital account deficits are brought back to zero, or "cured," by additional allocations from the capital accounts of the i-units and General Partner interest on a pro-rata basis. As a result the i-units' and General Partner interest's capital balances were reduced by $46.7 million and $1.0 million, respectively, to cure the deficit balances in the Class A and Class B common units. This initial curing did not impact earnings allocated to either the i-units or the General Partner interest.

Additional Curing

During 2015, in addition to the curing of the Class A and Class B common units resulting from the Drop Down, the carrying amounts for the capital accounts of the Class A and Class B common units were reduced below zero due to distributions to partners in excess of earnings attributable to partners. As a result, the capital balances of the i-units and General Partner interests were reduced by $185.4 million and $13.5 million, respectively, to cure the deficit balances in the Class A and Class B common units.

9. PARTNERS' CAPITAL – (continued)

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 February 2015, we filed with the SEC a new automatically effective shelf registration statement, or the 2015 Shelf, on Form S-3 that replaced our prior shelf registration statement which expired in December 2014. The 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

Issuance of Class A Common Units

In March 2015, we sold 8 million Class A common units in an underwritten public offering pursuant to the 2015 Shelf for net proceeds of \$288.8 million. The proceeds from the March 2015 offering were used to fund a portion of our capital expansion projects and for general partnership purposes.

The following table presents the net proceeds for our Class A common unit issuances for the current year.

2015 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[1]	General Partner Contribution[2]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amount)			
March	8,000,000	\$36.70	\$288.8	\$6.0	\$294.8

[1] Net of underwriters' fees and discounts, commissions and issuance expenses.

[2] Contributions made by the General Partner to maintain its 2% general partner interest.

10. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. Enbridge and its affiliates provide management and we obtain managerial, administrative, operational and workforce related services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among our General Partner, Enbridge Management, affiliates of Enbridge, and us. Pursuant to these service agreements, we have agreed to reimburse our General Partner, Enbridge Management and affiliates of Enbridge, for the cost of managerial, administrative, operational and director services they provide to us. Where directly attributable, the cost of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

The affiliate amounts incurred by us for services received pursuant to the services agreements are reflected in ''Operating and administrative — affiliate'' on our consolidated statements of income.

Financing Transactions with Affiliates

EUS 364-day Credit Facility

On March 9, 2015, we entered into an unsecured revolving 364-day credit agreement with EUS, which we refer to as the EUS 364-day Credit Facility. The EUS 364-day Credit Facility is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, \$750 million, (1) on a revolving basis for a 364-day period and (2) for a 364-day term on a non-revolving basis following the expiration of the revolving period. Loans under the EUS 364-day Credit Facility accrue interest based, at our election, on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. The EUS 364-day Credit Facility terminates on March 7, 2016, and including the option to term the revolving loan for a period of 364-days following the termination date, matures on March 6, 2017. There is no outstanding balance as of September 30, 2015 under the EUS 364-day Credit Facility.

10. RELATED PARTY TRANSACTIONS – (continued)

The commitment under the EUS 364-day Credit Facility may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to us from the sale by us of (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP.

Distribution from MEP

The following table presents distributions paid by MEP during the nine months ended September 30, 2015, to its public Class A common unitholders, representing the noncontrolling interest in MEP, and to us for our ownership of Class A common units.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total MEP Distribution
			(in millions)	
July 29, 2015	August 14, 2015	$ 8.8	$ 7.5	$16.3
April 29, 2015	May 15, 2015	8.6	7.4	16.0
January 28, 2015	February 13, 2015	8.5	7.3	15.8
		$25.9	$22.2	$48.1

Distribution to Series AC Interests

On January 2, 2015, we completed a transaction, or the Drop Down, pursuant to which we acquired the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline from our General Partner.

The following table presents the final ownership distribution for the fourth quarter of 2014 paid by the OLP to our General Partner and its affiliate on February 13, 2015, representing the noncontrolling interest in the Series AC, and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests. Pursuant to the OLP's partnership agreement, the final ownership distribution for the Series AC interests was distributed to Series AC partners of record as of the last day of the fourth quarter.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
January 29, 2015	February 13, 2015	$13.7	$27.5	$41.2

Amendment of OLP Limited Partnership Agreement

On July 30, 2015, the partners amended and restated the limited partnership agreement of the OLP, pursuant to which our General Partner will temporarily forego Series EA and ME, collectively, the Series, distributions commencing in the quarter ended June 30, 2015 through the quarter ending March 31, 2016. The General Partner's capital funding contribution requirements for each of those two Series, commencing in August 2015, will be reduced by the amount of its foregone cash distributions from the respective Series, until the earlier of December 31, 2016 and the date aggregate reductions in capital contributions for such Series are equal to the foregone cash distributions for such Series. To the extent that the General Partner's portion of capital contributions prior to December 31, 2016 are insufficient to cover the General Partner's foregone cash distributions for a Series, beginning with the distribution related to the first quarter of 2017 for that Series, we will receive reduced cash distributions by up to 50%, and the General Partner will receive a comparable increase in cash distributions each quarter until the General Partner has received an aggregate amount of contribution reductions and distribution increases equal to the amount of foregone cash distributions.

Joint Funding Arrangement for Eastern Access Projects

The OLP has a series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the U.S. Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. Our General Partner owns 75% of the EA interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the projects are jointly funded by our General Partner at 75% and us at 25%.

10. RELATED PARTY TRANSACTIONS – (continued)

Our General Partner made equity contributions totaling $119.3 million and $550.5 million to the OLP during the nine months ended September 30, 2015 and 2014, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Distribution to Series EA Interests

The following table presents distributions paid by the OLP during the nine months ended September 30, 2015, to our General Partner and its affiliate, representing the noncontrolling interest in the Series EA, and to us, as the holders of the Series EA general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series EA interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series EA Distribution
			(in millions)	
July 30, 2015	August 14, 2015	$56.5	$ —	$ 56.5
April 30, 2015	May 15, 2015	17.5	52.3	69.8
January 29, 2015	February 13, 2015	22.3	67.0	89.3
		$96.3	$119.3	$215.6

Joint Funding Arrangement for U.S. Mainline Expansion Projects

The OLP also has a series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. Our General Partner owns 75% of the ME interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the projects are jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion Joint Funding Agreement, which is similar to the Eastern Access Joint Funding Agreement.

Our General Partner has made equity contributions totaling $552.9 million and $384.0 million to the OLP for the nine months ended September 30, 2015, and 2014, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Distribution to Series ME Interests

The following table presents distributions paid by the OLP during the nine months ended September 30, 2015, to our General Partner and its affiliate, representing the noncontrolling interest in the Series ME, and to us, as the holders of the Series ME general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series ME interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series ME Distribution
			(in millions)	
July 30, 2015	August 14, 2015	$14.8	$ —	$14.8
April 30, 2015	May 15, 2015	1.5	4.5	6.0
January 29, 2015	February 13, 2015	1.8	5.2	7.0
		$18.1	$9.7	$27.8

10. RELATED PARTY TRANSACTIONS – (continued)

Noncontrolling Interests

The following table presents the components of net income (loss) attributable to noncontrolling interests as presented on our consolidated statements of income:

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)		(in millions)	
Alberta Clipper Interests	$ —	$16.3	$ (0.8)	$ 38.0
Eastern Access Interests	50.3	41.7	140.2	90.5
U.S. Mainline Expansion Interests	29.1	9.8	73.5	20.0
Midcoast Energy Partners, L.P.	(1.6)	2.9	(73.8)	0.9
Total	$77.8	$70.7	$139.1	$149.4

Sale of Accounts Receivable

We sold and derecognized receivables to a wholly-owned subsidiary of Enbridge for $911.8 million and $1,260.1 million for the three months ended September 30, 2015 and 2014, respectively, and $2,925.5 million and $3,792.8 million for the nine months ended September 30, 2015 and 2014, respectively. We received cash proceeds of $911.5 million and $1,259.8 million for the three months ended September 30, 2015 and 2014, respectively and $2,924.7 million and $3,791.8 million for the nine months ended September 30, 2015 and 2014, respectively. As of September 30, 2015, $341.3 million 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 ‘‘Operating and administrative — affiliate’’ expense in our consolidated statements of income. For the three and nine months ended September 30, 2015 and 2014, the cost stemming from the discount on the receivables sold was not material.

As of September 30, 2015 and December 31, 2014, we had $15.0 million and $71.9 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.

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale and are presented in ‘‘Commodity sales — affiliate’’ on our consolidated statements of income. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates, which are presented in ‘‘Transportation and other services — affiliate’’ on our consolidated statements of income.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Purchases of natural gas, NGLs, and crude oil from Enbridge and its affiliates are presented in ‘‘Commodity costs — affiliate’’ on our consolidated statements of income.

Related Party Transactions with Joint Ventures

We have a 35% aggregate indirect interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together include a 593-mile NGL intrastate transportation pipeline and a related NGL gathering system. Our equity investment in the Texas Express NGL system at September 30, 2015 and December 31, 2014, was $373.7 million and $380.6 million, respectively, which is included on our consolidated statements of financial position in ‘‘Other assets, net.’’ We recognized equity income of $8.9 million and $6.1 million for the three months ended September 30, 2015 and 2014, respectively, and $20.5 million and $7.1 million for the nine months ended September 30, 2015 and 2014, respectively, in ‘‘Other income’’ on our consolidated statements of income related to our investment in the system.

10. RELATED PARTY TRANSACTIONS – (continued)

We incurred $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 for our Natural Gas business. These expenses are included in "Commodity costs — affiliate" on our consolidated statements of income.

Our Natural Gas 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.

Lease and Storage Services Agreement

We have an agreement with Illinois Extension Pipeline Company, L.L.C., or IEPC, an equity method investment of our General Partner, pursuant to which IEPC built two storage tanks at our storage facility in Flanagan, Illinois. We lease the tanks from IEPC and operate them. IEPC will pay us operating fees for the operation of the tanks beginning in the fourth quarter of 2015.

11. 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 liquid hydrocarbon and natural gas pipeline operations, 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 other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our Liquids and Natural Gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate 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 and December 31, 2014, we had $101.6 million and $141.7 million, respectively, included in "Environmental liabilities," and $62.6 million and $60.1 million, respectively, included in "Other long-term liabilities," on our consolidated statements of financial position that we have accrued for costs we have recognized primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Lines 6A & 6B Crude Oil Releases

Line 6A Crude Oil Release

On September 9, 2010, a crude oil release occurred on Line 6A in Romeoville, Illinois, caused by a third party water pipeline failure which damaged our pipelines. One claim was filed against us and our affiliates by the State of Illinois in Illinois state court in connection with this crude oil release. On February 20, 2015, we agreed to a consent order releasing us from any claims, liability, or penalties.

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of our Lakehead system was reported near Marshall, Michigan. We estimate that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Kalamazoo River via Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 38 miles of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

We continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives we are undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

11. COMMITMENTS AND CONTINGENCIES – (continued)

On March 14, 2013, we received an order from the EPA, which we refer to as the Order, that required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015, the EPA acknowledged our completion of the Order.

In November 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality, or MDEQ. The MDEQ has oversight over submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

In May 2015, Enbridge reached a settlement with the MDEQ and the Michigan Attorney General's offices regarding the Line 6B crude oil release. As stipulated in the settlement, Enbridge agrees to: (1) provide at least 300 acres of wetland through restoration, creation, or banked wetland credits, to remain as wetland in perpetuity, (2) pay $5.0 million as mitigation for impacts to the banks, bottomlands, and flow of Talmadge Creek and the Kalamazoo River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the River, (3) continue to reimburse the State of Michigan for costs arising from oversight of Enbridge activities since the release, and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of Michigan.

As of September 30, 2015, our cumulative cost estimate for the Line 6B crude oil release remains at $1.2 billion.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at September 30, 2015. Our estimates exclude: (1) amounts we have capitalized, (2) any claims associated with the release that may later become evident, (3) amounts recoverable under insurance, and (4) fines and penalties from other governmental agencies except as described in the *Line 6B Fines and Penalties* section below. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

The material components underlying our cumulative estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response personnel and equipment	$ 548.5
Environmental consultants	227.0
Professional, regulatory and other	432.5
Total	$1,208.0

For the nine months ended September 30, 2015 and 2014, we made payments of $32.0 million and $117.4 million, respectively, for costs associated with the Line 6B crude oil release. As of September 30, 2015 and December 31, 2014, we had a remaining estimated liability of $157.9 million and $195.2 million, respectively.

11. COMMITMENTS AND CONTINGENCIES – (continued)

Fines and Penalties

At September 30, 2015, our remaining estimated costs related to the Line 6B crude oil release included \$47.5 million in fines and penalties. Of this amount, \$40.0 million relates to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, we believe that, based on the best information available at this time, the \$40.0 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which we expect will continue, and the limited information available to assess the matter, we are unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection, and emergency response to environmental events, and the cost of compliance with such measures, when combined with any fine or penalty, could be material. We have entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties, and injunctive relief are ongoing.

In June 2015, Enbridge reached a separate agreement with the United States of America (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the Potawatomi Indians, and the Nottawaseppi Huron Band of the Potawatomi Indians to pay approximately \$3.9 million that we had accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

Insurance

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates that renew throughout the year. On May 1 of each year, our insurance program is renewed and includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

A majority of the costs incurred for the crude oil release for Line 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of \$650.0 million for pollution liability for Enbridge and its affiliates. Including our remediation spending through September 30, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. As of September 30, 2015, we have recorded total insurance recoveries of \$547.0 million for the Line 6B crude oil release, out of the \$650.0 million aggregate limit. We will record receivables for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

In March 2013, we and Enbridge filed a lawsuit against the insurers of \$145.0 million of coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of \$42.0 million from the other remaining insurers and amended our lawsuit such that it included only one insurer.

Of the remaining \$103.0 million coverage limit, \$85.0 million is the subject matter of a lawsuit Enbridge filed against one particular insurer described above. In March 2015, Enbridge reached agreement with that insurer to submit the \$85.0 million claim to binding arbitration. The recovery of the remaining \$18.0 million is awaiting resolution of that arbitration, which is not scheduled to occur until fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance that we will prevail in the arbitration.

We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

Enbridge renewed its comprehensive property and liability insurance programs, under which we, together with Enbridge and its other affiliates are insured through April 30, 2016, with a liability program aggregate limit of

11. COMMITMENTS AND CONTINGENCIES – (continued)

$860.0 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement we have entered into with Enbridge, MEP, and other Enbridge subsidiaries.

Griffith Terminal Crude Oil Release

On February 25, 2014, a release of approximately 975 barrels of crude oil occurred within the Griffith Terminal in Griffith, Indiana. A repair plan has been reviewed with PHMSA and repair work has been completed. The released oil was fully contained within our facility and substantially all of the free product was recovered. The released oil did not affect the local community, wildlife or water supply. As of September 30, 2015, we had no remaining estimated liability.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects.

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately five actions or claims are pending against us and our affiliates in state and federal courts in connection with the Line 6B crude oil release. Based on the current status of these cases, we do not expect the outcome of these actions to be material to our results of operations or financial condition.

We have accrued a provision for future legal costs and probable losses associated with the Line 6A and Line 6B crude oil releases as described above in this footnote.

12. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. 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 interest rates and commodity prices, as well as to reduce volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments, including those that do not qualify for hedge accounting treatment, are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with the risks discussed above 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.

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

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	$ 137.8	$ 185.5
Other assets, net	55.6	93.3
Accounts payable and other[1]	(377.6)	(315.4)
Other long-term liabilities	(189.8)	(124.6)
Due from general partner and affiliates	—	0.3
	$(374.0)	$(160.9)

(1) Includes $16.2 million and $28.4 million held 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 the following contracts: (1) natural gas, (2) NGL, (3) crude oil and (4) interest rates.

During the first quarter of 2014, we determined that a portion of forecasted short term debt transactions were not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer met the cash flow hedging requirements. These terminations resulted in realized losses of $0.8 million for the nine months ended September 30, 2014. We had no similar terminations of our cash flow hedges for the nine months ended September 30, 2015.

Our earnings and cash flows are exposed to the variability in longer term interest rates ahead of the anticipated fixed rate debt issuances. Forward starting interest rate swaps are used as cash flow hedges against the effect of future interest rate movements on earnings and cash flow. In order to mitigate the negative effect that increasing interest rates have on our cash flows, in the three months ended September 30, 2014, we purchased 10-year interest rate swaps with a total notional value of $2.35 billion.

In September 2014, we amended the maturity date on certain interest rate hedges of future debt issuances that were originally set to mature in 2014 and 2016 to better reflect the expected timing of future debt issuances. The ineffective portion of the hedges' fair value in relation to the hedged future debt issuances is recognized in income at the amendment date and each quarter end. For the three and nine months ended September 30, 2015, we recognized in interest expense unrealized losses for hedge ineffectiveness of approximately $7.9 million and unrealized gains for hedge ineffectiveness of approximately $22.0 million, respectively, associated with interest rate hedges that were originally set to mature in 2014 and 2016. For the three and nine months ended September 30, 2014, we recognized in interest expense unrealized losses for hedge ineffectiveness of approximately $62.2 million, also associated with interest rate hedges that were originally set to mature in 2014 and 2016.

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

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]	(106.2)	(49.8)
A	(128.3)	(129.1)
Lower than A	(139.7)	17.9
	$(374.0)	$(160.9)

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

(2) Includes $16.2 million and $28.4 million held 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 and interest rates, 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 or posted in the balances listed above. At September 30, 2015 and December 31, 2014, we held $16.2 million and $28.4 million of cash collateral on our asset exposures, respectively. 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.

We have provided letters of credit totaling $417.7 million and $329.6 million relating to our liability exposures pursuant to the margin thresholds in effect at September 30, 2015 and December 31, 2014, respectively, under our ISDA® agreements. 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 interest rate and 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 at 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 $83.5 million.

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

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]	$(251.1)	$(147.1)
Non-United States financial institutions	(149.9)	(54.2)
Other	27.0	40.4
	$(374.0)	$(160.9)

(1) Includes $16.2 million and $28.4 million held 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.

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 hedging instruments:[1]					
Interest rate contracts	Accounts payable and other	$ —	$ —	$(319.4)	$(241.0)
Interest rate contracts	Other long-term liabilities	—	—	(168.0)	(102.0)
Commodity contracts	Other current assets	7.4	26.1	—	—
Commodity contracts	Other assets	—	2.1	—	—
		7.4	28.2	(487.4)	(343.0)
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	130.4	159.4	—	—
Commodity contracts	Other assets	55.6	91.2	—	—
Commodity contracts	Accounts payable and other[2]	—	—	(42.0)	(46.0)
Commodity contracts	Other long-term liabilities	—	—	(21.8)	(22.6)
Commodity contracts	Due from general partner and affiliates	—	0.3	—	—
		186.0	250.9	(63.8)	(68.6)
Total derivative instruments		$193.4	$279.1	$(551.2)	$(411.6)

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

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

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

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. Also included in AOCI, as of September 30, 2015 and December 31, 2014, are unrecognized losses of approximately $23.9 million and $28.4 million, respectively, associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated, settled, or terminated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the nine months ended September 30, 2015 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 $316.5 million, representing unrealized net losses 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.

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					
Interest rate contracts	$(127.0)	Interest expense	$ (3.7)	Interest expense	$ (7.8)
Commodity contracts	(5.5)	Commodity Costs	8.6	Commodity Costs	(0.1)
Total	$(132.5)		$ 4.9		$ (7.9)
For the three months ended September 30, 2014					
Interest rate contracts	$ 44.1	Interest expense	$ (4.0)	Interest expense	$(62.2)
Commodity contracts	11.2	Commodity Costs	(2.1)	Commodity Costs	0.9
Total	$ 55.3		$ (6.1)		$(61.3)
For the nine months ended September 30, 2015					
Interest rate contracts	$(169.0)	Interest expense	$(12.0)	Interest expense	$ 24.6
Commodity contracts	(16.8)	Commodity Costs	24.1	Commodity Costs	(4.1)
Total	$(185.8)		$ 12.1		$ 20.5
For the nine months ended September 30, 2014					
Interest rate contracts	$ (93.0)	Interest expense	$(12.1)	Interest expense	$(73.2)
Commodity contracts	7.9	Commodity Costs	(12.4)	Commodity Costs	1.5
Total	$ (85.1)		$(24.5)		$(71.7)

(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.

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges	
	2015	2014
	(in millions)	
Balance at January 1	$(211.4)	$ (76.6)
Other comprehensive loss before reclassifications[1]	(170.9)	(104.6)
Amounts reclassified from AOCI[2][3]	(6.4)	22.2
Net other comprehensive loss	$(177.3)	$ (82.4)
Balance at September 30	$(388.7)	$(159.0)

(1) Excludes NCI gain of $1.8 million and NCI loss of $0.5 million reclassified from AOCI at September 30, 2015 and 2014, respectively.

(2) Excludes NCI loss of $5.7 million and NCI gain of $2.3 million reclassified from AOCI at September 30, 2015 and 2014, respectively.

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

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:				
Interest Rate Contracts[1][2]	$ 3.6	$4.0	$ 11.9	$12.1
Commodity Contracts[3][4][5]	(6.5)	1.6	(18.3)	10.1
Total Reclassifications from AOCI	$(2.9)	$5.6	$ (6.4)	$22.2

(1) Loss reported within "Interest expense, net" in the consolidated statements of income.

(2) Excludes NCI gain of $0.1 million reclassified from AOCI for the three and nine months ending September 30, 2015.

(3) Loss (gain) reported within "Commodity costs" in the consolidated statements of income.

(4) Excludes NCI gain of $2.1 million and $0.5 million reclassified from AOCI for the three months ending September 30, 2015 and 2014, respectively.

(5) Excludes NCI loss of $5.8 million and gain of $2.3 million reclassified from AOCI for the nine months ending 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	Transportation and other services[3]	$ 8.1	$ 7.0	$ 8.1	$ (0.6)
Commodity contracts	Commodity sales	(7.2)	7.6	(22.4)	10.7
Commodity contracts	Commodity sales – affiliate	—	—	(0.3)	0.5
Commodity contracts	Commodity costs[4]	40.8	9.5	44.3	(9.9)
Commodity contracts	Power	—	—	—	0.5
Total		$41.7	$24.1	$ 29.7	$ 1.2

(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 settlement gains of $7.0 million and $0.6 million for the three months ended September 30, 2015 and 2014, respectively, and settlement gains of $19.2 million and $0.9 million for the nine months ended September 30, 2015 and 2014, respectively.

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

(4) Includes settlement gains of $27.3 million and $0.2 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.

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	$193.4	$—	$193.4	$(59.9)	$133.5

	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	$279.1	$—	$279.1	$(91.8)	$187.3

(1) Includes $16.2 million and $28.4 million of cash collateral held 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	$(567.4)	$—	$(567.4)	$59.9	$(507.5)

	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	$(440.0)	$—	$(440.0)	$91.8	$(348.2)

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

12. 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 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)							
Interest rate contracts	$—	$(487.4)	$ —	$(487.4)	$—	$(343.0)	$ —	$(343.0)
Commodity contracts:								
Financial	—	17.6	14.3	31.9	—	41.6	42.7	84.3
Physical	—	—	4.6	4.6	—	—	19.5	19.5
Commodity options	—	—	93.1	93.1	—	—	106.7	106.7
	—	(469.8)	112.0	(357.8)	—	(301.4)	168.9	(132.5)
Cash collateral				(16.2)				(28.4)
Total				$(374.0)				$(160.9)

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, crude oil and power) 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.

12. 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 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 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.

12. 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 in (out) of Level 3[1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Commodity sales	—	(3.2)	—	(3.2)
Reported in Commodity costs	(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 September 30, 2015	$ 14.3	$ 4.6	$ 93.1	$ 112.0
Amounts reported in Commodity sales	$ —	$(22.7)	$ —	$ (22.7)
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets and liabilities still held at the reporting date:				
Reported in Commodity sales	$ —	$ (1.4)	$ —	$ (1.4)
Reported in Commodity costs	$ (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.

12. 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	528,532	$86.11	$45.66	$21.3	$ —	$65.0	$ —
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	779,270	$74.00	$49.08	$19.3	$ —	$ 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 ($0.5) million at September 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

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

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 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 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.

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

Fair Value Measurements of Interest Rate Derivatives

We enter into interest rate swaps, caps and derivative financial instruments with similar characteristics to manage the cash flow associated with future interest rate movements on our indebtedness. The following table provides information about our current interest rate derivatives for the specified periods.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value[2] at September 30, 2015	Fair Value[2] at December 31, 2014
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 510	1.53%	$ —	$ (0.2)
Contracts maturing in 2016					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 90	0.55%	$ (0.1)	$ (0.1)
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 500	2.21%	$ (10.5)	$ (12.9)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (9.0)	$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (7.9)	$ (3.3)
Contracts settling prior to maturity					
2015 – Pre-issuance Hedges	Cash Flow Hedge	$1,000	5.48%	$(313.0)	$(258.3)
2016 – Pre-issuance Hedges	Cash Flow Hedge	$ 500	4.21%	$ (85.3)	$ (63.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.69%	$ (52.7)	$ (36.0)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (13.4)	$ (4.9)

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from 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 of approximately $4.5 million and $37.4 million at September 30, 2015 and December 31, 2014, respectively.

13. 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% for the nine months ended September 30, 2015 and 2014. Our income tax expense was $4.6 million and $3.2 million for the three and nine months ended September 30, 2015, respectively. Our income tax expense was $2.1 million and $6.1 million for the three and nine months ended September 30, 2014, respectively.

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 $21.5 million and $21.7 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.

13. INCOME TAXES – (continued)

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 $5.4 million at September 30, 2015.

14. 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, because each business segment requires different operating strategies. We have segregated our business activities into two distinct operating segments:

- Liquids; and
- Natural Gas.

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

	For the three months ended September 30, 2015			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:				
Commodity sales	$ —	$609.9	$ —	$ 609.9
Transportation and other services	606.7	51.1	—	657.8
	606.7	661.0[2]	—	1,267.7
Operating expenses:				
Commodity costs	—	522.7	—	522.7
Environmental costs, net of recoveries	1.1	—	—	1.1
Operating and administrative	183.2	94.1	3.3	280.6
Power	71.6	—	—	71.6
Depreciation and amortization	97.7	39.2	—	136.9
	353.6	656.0	3.3	1,012.9
Operating income (loss)	253.1	5.0	(3.3)	254.8
Interest expense, net	—	—	(88.2)	(88.2)
Allowance for equity used during construction	—	—	13.7	13.7
Other income	—	8.9[3]	(0.1)	8.8
Income (loss) before income tax expense	253.1	13.9	(77.9)	189.1
Income tax expense	—	—	(4.6)	(4.6)
Net income (loss)	253.1	13.9	(82.5)	184.5
Less: Net income attributable to:				
Noncontrolling interest	—	—	77.8	77.8
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	2.1	2.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$253.1	$ 13.9	$(184.9)	$ 82.1

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

(2) There were no intersegment revenues for the three months ended September 30, 2015.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

14. SEGMENT INFORMATION – (continued)

	For the three months ended September 30, 2014			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:				
Commodity sales	$ —	$1,347.0	$ —	$1,347.0
Transportation and other services	542.9	52.4	—	595.3
	542.9	1,399.4	—	1,942.3
Operating expenses:				
Commodity costs	—	1,238.2	—	1,238.2
Environmental costs, net of recoveries	50.1	—	—	50.1
Operating and administrative	126.5	105.0	3.8	235.3
Power	59.5	—	—	59.5
Depreciation and amortization	79.3	39.5	—	118.8
	315.4	1,382.7	3.8	1,701.9
Operating income (loss)	227.5	16.7	(3.8)	240.4
Interest expense, net	—	—	(137.1)	(137.1)
Allowance for equity used during construction	—	—	14.5	14.5
Other income (expense)[2]	—	6.1	(4.3)	1.8
Income (loss) before income tax expense	227.5	22.8	(130.7)	119.6
Income tax expense	—	—	(2.1)	(2.1)
Net income (loss)	227.5	22.8	(132.8)	117.5
Less: Net income attributable to:				
Noncontrolling interest	—	—	70.7	70.7
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.8	3.8
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$227.5	$ 22.8	$(229.8)	$ 20.5

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

(2) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

14. SEGMENT INFORMATION – (continued)

	As of and for the nine months ended September 30, 2015			
	Liquids	Natural Gas	Corporate[(1)]	Total
	(in millions)			
Operating revenues:[(2)]				
Commodity sales	$ —	$2,163.7	$ —	$ 2,163.7
Transportation and other services	1,694.8	150.9	—	1,845.7
	1,694.8	2,314.6	—	4,009.4
Operating expenses:				
Commodity costs	—	1,972.4	—	1,972.4
Environmental costs, net of recoveries	1.1	—	—	1.1
Operating and administrative	429.9	264.1	10.9	704.9
Power	192.4	—	—	192.4
Goodwill impairment	—	246.7	—	246.7
Asset impairment	—	12.3	—	12.3
Depreciation and amortization	276.5	118.3	—	394.8
	899.9	2,613.8	10.9	3,524.6
Operating income (loss)	794.9	(299.2)	(10.9)	484.8
Interest expense, net	—	—	(214.5)	(214.5)
Allowance for equity used during construction	—	—	54.0	54.0
Other income	—	20.5[(3)]	0.2	20.7
Income (loss) before income tax expense	794.9	(278.7)	(171.2)	345.0
Income tax expense	—	—	(3.2)	(3.2)
Net income (loss)	794.9	(278.7)	(174.4)	341.8
Less: Net income attributable to:				
Noncontrolling interest	—	—	139.1	139.1
Series 1 preferred unit distributions	—	—	67.5	67.5
Accretion of discount on Series 1 preferred units	—	—	10.1	10.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 794.9	$ (278.7)	$(391.1)	$ 125.1
Total assets	$13,059.7	$5,177.5[(4)]	$ 169.7	$18,406.9
Capital expenditures (excluding acquisitions)	$ 1,485.4	$ 143.8	$ 3.5	$ 1,632.7

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

(2) There were no intersegment revenues for the nine months ended September 30, 2015.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(4) Total assets for our Natural Gas segment include $373.7 million for our equity investment in the Texas Express NGL system.

14. SEGMENT INFORMATION – (continued)

	As of and for the nine months ended September 30, 2014			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:				
Commodity sales	$ —	$4,288.9	$ —	$ 4,288.9
Transportation and other services	1,449.9	154.2	—	1,604.1
	1,449.9	4,443.1	—	5,893.0
Operating expenses:				
Commodity costs	—	3,986.7	—	3,986.7
Environmental costs, net of recoveries	93.3	—	—	93.3
Operating and administrative	352.5	317.5	6.9	676.9
Power	164.1	—	—	164.1
Depreciation and amortization	222.7	113.3	—	336.0
	832.6	4,417.5	6.9	5,257.0
Operating income (loss)	617.3	25.6	(6.9)	636.0
Interest expense, net	—	—	(294.2)	(294.2)
Allowance for equity used during construction	—	—	47.8	47.8
Other income (expense)	—	7.1[2]	(4.9)	2.2
Income (loss) before income tax expense	617.3	32.7	(258.2)	391.8
Income tax expense	—	—	(6.1)	(6.1)
Net income (loss)	617.3	32.7	(264.3)	385.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	149.4	149.4
Series 1 preferred unit distributions	—	—	67.5	67.5
Accretion of discount on Series 1 preferred units	—	—	11.1	11.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 617.3	$ 32.7	$(492.3)	$ 157.7
Total assets	$11,252.8	$5,461.9[3]	$ 232.4	$16,947.1
Capital expenditures (excluding acquisitions)	$ 1,861.3	$ 158.4	$ 3.2	$ 2,022.9

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

(2) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(3) Total assets for our Natural Gas segment includes $380.2 million for our equity investment in the Texas Express NGL system.

15. SUPPLEMENTAL CASH FLOWS 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 ‘‘Investment in joint venture’’):

	For the nine months ended September 30,	
	2015	2014
	(in millions)	
Additions to property, plant and equipment	$1,556.2	$2,055.8
Increase (decrease) in construction payables	76.5	(32.9)
Total capital expenditures (excluding ‘‘Investment in joint venture’’)	$1,632.7	$2,022.9

16. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative regulatory accounting provisions to a number of our pipeline projects that meet the criteria outlined for regulated operations. The rates for Southern Access, Alberta Clipper, the Mainline Expansion Project, Eastern Access, the Line 6B 75-mile Replacement Project, Line 6B Integrity Project, and the Line 14 Project, which are currently the primary applicable projects, are based on a cost-of-service recovery model that follows the Federal Energy Regulatory Commission, or FERC, authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls annually based on forecast volumes and costs. A difference between forecast and actual results causes an over or under recovery in any given year. These over or under recoveries are deferred through a revenue adjustment and are returned to or recovered from shippers through future rate adjustments in the following year. Under the authoritative accounting provisions applicable to our regulated operations, over or under recoveries are recognized in the financial statements in the current period. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with the FERC and through toll rate adjustments with our customers.

Due to over or under recovery revenue adjustments made in accordance with the FERC's authoritative guidance and our cost-of-service tariff methodology, we recognize assets and liabilities for regulatory purposes. The assets and liabilities that we recognize for regulatory purposes are recorded on a net basis in ''Other current assets'' or ''Accounts payable and other,'' respectively, on our consolidated statements of financial position. The net regulatory asset or liability balance is comprised of the cumulative over and under recovery revenue adjustments made during the prior year, less any amortizations, and the cumulative over and under recovery revenue adjustments made during the current year to date. We track regulatory assets and liabilities by vintage, and our regulatory assets and liabilities are amortized on a straight-line basis over a one-year recovery period. Accordingly, amortization for a net regulatory asset or liability arising from over and under recovery adjustments related to any given calendar year does not begin until January of the following year. The changes in our net regulatory asset balance for the three and nine months ended September 30, 2015 and 2014 are as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Net regulatory asset balance at beginning of period	$ 2.0	$(1.2)	$ 6.0	$ 7.7
Current period (over)/under recovery revenue adjustments	24.0	(4.4)	24.5	(5.6)
Amortization of prior year regulatory asset	(0.8)	—	(5.3)	(7.7)
Net regulatory asset (liability) balance at end of period	$25.2	$(5.6)	$25.2	$(5.6)

Other Contractual Obligations

Southern Access Pipeline

We have entered into certain contractual obligations with our customers on the Southern Access Pipeline in which a portion of the revenue earned on volumes above certain predetermined shipment levels, or qualifying volumes, are returned to the shippers through future rate adjustments. At September 30, 2015 and December 31, 2014 we had no qualifying volume liabilities related to the Southern Access Pipeline on our consolidated statements of financial position.

During 2013, we incurred liabilities related to contractual obligations with our customers on the Southern Access Pipeline related to qualifying volumes. We did not incur any similar liabilities during 2014. As a result, in 2013, we recorded a liability for the contractual amounts due back to our shippers with the corresponding amount as a reduction to revenue. We amortized the liability on a straight-line basis as an adjustment to revenue in the following year, reflecting the related rate adjustment. For the three and nine months ended September 30, 2014, we amortized through revenue $1.7 million and $6.1 million, respectively, of qualifying volume liabilities on our consolidated statements of income, with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

16. REGULATORY MATTERS – (continued)

Alberta Clipper Pipeline

A portion of the rates we charge our customers includes an estimate for annual property taxes. If the estimated property tax we collect from our customers is significantly higher than the actual property tax imposed, we are contractually obligated to refund 50% of the property tax over recovery to our customers. At September 30, 2015 and December 31, 2014, we had $1.6 million and $5.9 million, respectively, in property tax over recovery liabilities related to our Alberta Clipper Pipeline on our consolidated statements of financial position.

During 2014 and 2013, we incurred liabilities related to contractual obligations with our customers on the Alberta Clipper Pipeline related to property taxes. As a result, in 2014 and 2013, we recorded a liability for the contractual amounts due back to our shippers with the corresponding amount as a reduction to revenue. We amortized the liability on a straight-line basis as an adjustment to revenue in the following year, reflecting the related rate adjustment. For the three and nine months ended September 30, 2015, we amortized through revenue $1.1 million and $4.0 million of property tax over recovery liabilities, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position. For the three and nine months ended September 30, 2014, we amortized through revenue $1.7 million and $5.2 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Line 3 Replacement, Line 6B 75-mile Replacement and Mainline Expansion Projects, we recorded $13.7 million and $54.0 million of ‘‘Allowance for equity used during construction’’ in our consolidated statement of income for the three and nine months ended September 30, 2015, respectively, with a corresponding amount of $54.0 million in ‘‘Property, plant and equipment’’ on our consolidated statement of financial position at September 30, 2015. We recorded $14.5 million and $47.8 million of ‘‘Allowance for equity used during construction’’ in our consolidated statements of income for the three and nine months ended September 30, 2014, respectively, with a corresponding amount of $47.8 million in ‘‘Property, plant and equipment’’ on our consolidated statement of financial position at September 30, 2014.

17. 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.

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED – (continued)

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, though 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.

18. SUBSEQUENT EVENTS

Credit Facility Extension

On October 23, 2015, we amended our Credit Facility to extend the maturity date from September 26, 2019 to September 26, 2020 except for $175.0 million of commitments that will expire on September 26, 2018.

Senior Notes Offering

On October 6, 2015, we closed a public offering of $1.6 billion of senior unsecured notes, comprising $500 million aggregate principal amount of notes due October 15, 2020, $500 million aggregate principal amount of notes due October 15, 2025 and $600 million aggregate principal amount of notes due October 15, 2045 for net proceeds of approximately $1.575 billion after deducting underwriting discounts and commissions and estimated offering expenses. In connection with the offering, we paid $314.7 million to settle certain pre-issuance hedges. Of that amount, a loss of $78.6 million is expected to be recognized in interest expense in the fourth quarter of 2015 from ineffectiveness. The remaining loss of $236.1 million is expected to be amortized as interest expense over a term of eight to ten years.

18. SUBSEQUENT EVENTS – (continued)

Distribution to Partners

On October 30, 2015, the board of directors of Enbridge Management declared a distribution payable to our partners on November 13, 2015. The distribution will be paid to unitholders of record as of November 6, 2015 of our available cash of $258.7 million at September 30, 2015, or $0.5830 per limited partner unit. Of this distribution, $216.0 million will be paid in cash, $41.8 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.9 million will be retained from our General Partner from amounts otherwise distributable to it in respect of its general partner interest and limited partner interest to maintain its 2% general partner interest.

Distribution to Series EA Interests

On October 30, 2015, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay the entire distribution of $76.1 million to us.

Distribution to Series ME Interests

On October 30, 2015, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series ME interests, declared a distribution payable to the holders of the Series ME general and limited partner interests. The OLP will pay the entire distribution of $32.5 million to us.

Distribution from MEP

On October 29, 2015, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to their partners on November 13, 2015. The distribution will be paid to unitholders of record as of November 6, 2015, of MEP's available cash of $16.5 million at September 30, 2015, or $0.3575 per limited partner unit. MEP will pay $7.6 million to their public Class A common unitholders, while $8.9 million in the aggregate will be paid to us with respect to our Class A common units, our subordinated units, and to 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 acting in its capacity as general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of November 6, 2015. Midcoast Operating will pay $25.7 million to us and $27.4 million to MEP.

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* of this report and in conjunction with the audited consolidated financial statements and accompanying footnotes in our Annual Report on Form 10-K for the year ended December 31, 2014, as filed with the Securities and Exchange Commission, or the SEC, on February 18, 2015.

RESULTS OF OPERATIONS — OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum; and
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities, along with supply, transportation and sales services, including providing marketing services for natural gas and NGLs.

We conduct our business through two business segments: Liquids and Natural Gas. Our Liquids segment includes the operations of our Lakehead, Mid-Continent, and North Dakota systems. These systems largely consist of Federal Energy Regulatory Commission, or FERC, regulated interstate crude oil and liquid petroleum pipelines, gathering systems and storage facilities. The Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. Our Liquids systems generate revenues primarily from charging shippers a rate per barrel to gather, transport and store crude oil and liquid petroleum.

Our Natural Gas segment includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, and NGL fractionation facilities. Moreover, our Natural Gas segment also provides supply, transmission, storage and sales services to producers and wholesale customers on our natural gas gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Revenues for our Natural Gas segment 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. Additionally, we provide other services that are valued by our customers. Segment gross margin is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing services in addition to the proceeds we receive for sales of natural gas, NGLs and condensate to affiliates and third-parties.

The following table reflects our operating income by business segment and corporate charges for each of 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				
Liquids	$253.1	$ 227.5	$ 794.9	$ 617.3
Natural Gas	5.0	16.7	(299.2)	25.6
Corporate, operating and administrative	(3.3)	(3.8)	(10.9)	(6.9)
Total operating income	254.8	240.4	484.8	636.0
Interest expense	(88.2)	(137.1)	(214.5)	(294.2)
Allowance for equity used during construction	13.7	14.5	54.0	47.8
Other income	8.8	1.8	20.7	2.2
Income before income tax expense	189.1	119.6	345.0	391.8
Income tax expense	(4.6)	(2.1)	(3.2)	(6.1)
Net income	184.5	117.5	341.8	385.7
Less: Net income attributable to:				
Noncontrolling interest	77.8	70.7	139.1	149.4
Series 1 preferred unit distributions	22.5	22.5	67.5	67.5
Accretion of discount on Series 1 preferred units	2.1	3.8	10.1	11.1
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 82.1	$ 20.5	$ 125.1	$ 157.7

Highlights

Liquids

Our Liquids segment operating income increased $25.6 million and $177.6 million for the three and nine months ended September 30, 2015, respectively, as compared to the same periods in 2014. Liquids segment operating income increased primarily due to additional assets placed in service and an increase in volumes on our systems. In 2014 and 2015, $2.7 billion and $0.7 billion of additional assets, respectively, were placed into service on our Lakehead system, including portions of the Eastern Access, Mainline Expansion projects, and other projects. Average daily volumes delivered on our liquids systems increased 177,000 Bpd, or 6.5%, and 266,000 Bpd, or 10.3%, for the three and nine months ended September 30, 2015, respectively, when compared to the same periods in 2014 due to increased capacity. Lastly, Liquids segment operating income increased as a result of reduced environmental costs, net of recoveries, primarily due to lower environmental accruals, net of recoveries, related to the Line 6B crude oil release.

Natural Gas

Our Natural Gas segment operating income decreased $11.7 million and $324.8 million for the three and nine months ended September 30, 2015, respectively, primarily as a result of a non-cash impairment charge $246.7 million in goodwill impairment that was recorded during the second quarter of 2015. In addition, segment gross margin decreased due to decreased non-cash, mark-to-market net gains of $11.5 million and losses of $65.0 million for the three and nine months ended September 30, 2015, respectively, when compared to the same periods in 2014. Furthermore, there were declines in natural gas pricing differentials and production volumes for the three and nine months ended September 30, 2015, when compared to the same periods in 2014, primarily due to the current low commodity pricing environment. We expect that the current pricing environment trends will continue throughout 2015 and into 2016. These decreases in segment gross margin were slightly offset by higher storage margins as a result of sale of liquids product inventory at prevailing market prices relative to the cost of product inventory volumes for the three and nine months ended September 30, 2015.

Derivative Transactions and Hedging Activities

Contractual arrangements in our Liquids, Natural Gas, and Corporate segments expose us to market risks associated with changes in (1) commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs and (2) interest rates on our variable rate debt. 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 and interest rates, 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 or interest rates. 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 follows:

- Liquids segment commodity-based derivatives — "Transportation and other services" and "Power"
- Natural Gas segment commodity-based derivatives — "Commodity sales" and "Commodity costs"
- Corporate interest rate derivatives — "Interest expense"

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)			
Liquids segment:				
Non-qualified hedges	$ 1.1	$ 6.5	$(11.1)	$ (1.0)
Natural Gas segment:				
Hedge ineffectiveness	(0.1)	0.9	(4.1)	1.5
Non-qualified hedges	6.3	16.8	(49.4)	10.0
Commodity derivative fair value net gains (losses)	7.3	24.2	(64.6)	10.5
Corporate:				
Interest rate hedge ineffectiveness	(7.8)	(62.2)	24.6	(73.2)
Derivative fair value net losses	$(0.5)	$(38.0)	$(40.0)	$(62.7)

RESULTS OF OPERATIONS — BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets 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 Results:				
Operating revenue	$606.7	$542.9	$1,694.8	$1,449.9
Operating expenses:				
Environmental costs, net of recoveries	1.1	50.1	1.1	93.3
Operating and administrative	183.2	126.5	429.9	352.5
Power	71.6	59.5	192.4	164.1
Depreciation and amortization	97.7	79.3	276.5	222.7
Total operating expenses	353.6	315.4	899.9	832.6
Operating income	$253.1	$227.5	$ 794.9	$ 617.3
Operating Statistics				
Lakehead system:				
United States[(1)]	1,905	1,711	1,869	1,635
Province of Ontario[(1)]	433	461	423	453
Total Lakehead system delivery volumes[(1)]	2,338	2,172	2,292	2,088
Barrel miles (billions)	164	152	471	430
Average haul (miles)	764	758	753	755
Mid-Continent system delivery volumes[(1)]	216	191	212	193
North Dakota system:				
Trunkline[(1)]	331	345	344	300
Gathering[(1)]	2	2	2	3
Total North Dakota system delivery volumes[(1)]	333	347	346	303
Total Liquids segment delivery volumes[(1)]	2,887	2,710	2,850	2,584

(1) Average barrels per day in thousands.

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

Operating income of our Liquids segment for the three months ended September 30, 2015, increased $25.6 million, as compared with the same period in 2014, primarily due to the reasons discussed below.

Our operating revenue increased $63.8 million for the three months ended September 30, 2015, when compared with the same period in 2014 due to the following reasons. Operating revenue increased $5.6 million, primarily due to higher average rates. Operating revenue also increased $73.1 million from increased surcharge revenue for projects on our Lakehead system subject to regulatory accounting, primarily as a result of placing $2.7 billion and $0.7 billion of additional assets into service on the Lakehead system in 2014 and through the first nine months of 2015, respectively. These additional assets placed into service included components of the Eastern Access, Mainline Expansion series, and other expansion projects. These amounts were partially offset by a $32.5 million decrease in rates due to greater qualifying volume credits related to Lakehead toll revenues. Qualifying volume credits represent a contractual obligation, which were introduced with the original Southern Access and Alberta Clipper expansions, to return a portion of the revenue to our shippers when volumes shipped exceed certain predetermined levels. Once these predetermined levels are exceeded, the expansion projects are earning their full cost-of-service. Hence, to limit project earnings to agreed levels, the credits are returned to the shippers through the tolls.

Additionally, operating revenue increased $13.9 million due to increased average daily delivery volumes. Volumes delivered increased by 177,000 Bpd, of which 166,000 Bpd and $15.3 million in revenues were attributable to higher volumes on the Lakehead system as a result of additional system capacity from the aforementioned assets that were placed into service. Finally, our operating revenue also increased by $8.5 million due to a surcharge that went into effect on April 1, 2015, which is designed to recover half of the costs of a hydrostatic test on Line 2B.

Environmental costs, net of recoveries, decreased $49.0 million for the three months ended September 30, 2015, when compared with the same period in 2014. This decrease is primarily related to cost accruals for the Line 6B crude oil release. There were no cost accruals or insurance recoveries related to Line 6B for the three months ended September 30, 2015. For the same three months ended 2014, there were $50.9 million of cost accruals and no insurance recoveries.

The operating and administrative expenses of our Liquids segment increased $56.7 million for the three months ended September 30, 2015, when compared with the same period in 2014, primarily due to cost increases of $8.7 million of property taxes and $47.9 million of pipeline integrity costs. The increase in property taxes is primarily resulted from the additional assets placed into service during 2014 and 2015. The increase in pipeline integrity costs relates to $51.4 million for the three months ended September 30, 2015, for the hydrostatic test on Line 2B. The costs related to the Line 2B hydrostatic test were partially offset by the $8.5 million of surcharge revenues discussed above.

Power costs increased $12.1 million for the three months ended September 30, 2015, when compared to the same period in 2014, primarily as a result of an increase in volumes on our systems.

The increase in depreciation expense of $18.4 million for the three months ended September 30, 2015, when compared to the same period in 2014 is directly attributable to additional assets placed into service, primarily on the projects discussed above.

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

Operating income of our Liquids segment for the nine months ended September 30, 2015, increased $177.6 million, as compared with the same period in 2014, primarily due to the reasons discussed below.

Operating revenue increased $244.9 million for the nine months ended September 30, 2015, when compared with the same period in 2014 due to the following reasons. Operating revenue increased $25.0 million due to higher average rates. Operating revenue also increased $207.2 million from increased surcharge revenue for projects on our Lakehead system subject to regulatory accounting, primarily as a result of placing $2.7 billion and $0.7 billion of additional assets into service on the Lakehead system in 2014 and through the first nine months of 2015, respectively. These additional assets placed into service included components of the Eastern Access, Mainline Expansion series, and other expansion projects. These amounts were partially offset by a $70.2 million decrease in rates due to greater qualifying volume credits related to Lakehead toll revenues.

Additionally, operating revenue increased $69.5 million due to increased average daily delivery volumes. Volumes delivered increased by 266,000 Bpd, of which 204,000 Bpd and $53.5 million in revenues were attributable to higher volumes on the Lakehead system as a result of additional system capacity from the aforementioned assets that were placed into service. The North Dakota system experienced an increase of 43,000 Bpd and $12.6 million in revenues as shippers shifted volumes onto this system and away from higher cost alternatives such as transportation by rail. Finally, our operating revenue also increased by $16.2 million due to a surcharge that went into effect on April 1, 2015, which is designed to recover half of the costs of a hydrostatic test on Line 2B.

Environmental costs, net of recoveries, decreased $92.2 million for the nine months ended September 30, 2015, when compared with the same period in 2014. This decrease is primarily related to cost accruals for the Line 6B crude oil release. There were no cost accruals or insurance recoveries related to Line 6B for the nine months ended September 30, 2015. For the same period ended 2014, there were $85.9 million of cost accruals and no insurance recoveries.

The operating and administrative expenses of our Liquids segment increased $77.4 million for the nine months ended September 30, 2015 when compared with the same period in 2014, primarily due to $48.0 million of pipeline integrity costs. The increase in pipeline integrity costs relates to $53.3 million for the three months ended September 30, 2015, for the hydrostatic test on Line 2B. The costs related to the Line 2B hydrostatic test were partially offset by the $16.2 million of surcharge revenues discussed above.

Additionally, the increase in operating and administrative expenses was also due to cost increases of $11.1 million of property taxes, $8.1 million of workforce related costs and $11.9 million of other operating and administrative expenses, mainly consisting of contract labor, insurance, rents and lease payments, and professional and regulatory services. These cost increases primarily resulted from the additional assets placed into service during 2014 and 2015.

Power costs increased $28.3 million for the nine months ended September 30, 2015, when compared to the same period in 2014, primarily as a result of an increase in volumes on our systems.

The increase in depreciation expense of $53.8 million for the nine months ended September 30, 2015, when compared to the same period in 2014, is directly attributable to additional assets placed into service, primarily on the projects discussed above.

Future Prospects Update for Liquids

A review of a potential transfer of Enbridge's United States liquids pipelines assets to us determined that market conditions do not support a large scale drop down at this time. We currently have over $6 billion of secured growth projects coming into service through 2019 and options to increase our economic interest in projects that are jointly funded by us and Enbridge. Enbridge has a large inventory of United States liquids pipelines assets and continues to evaluate selective drop down opportunities of approximately $500 million annually, subject to market conditions and our financing capacity.

Impact of Commodity Price Declines

Volatility in commodity prices can impact production volumes in the oil sands region of Western Canada and the Bakken region of North Dakota, our two primary crude oil supply basins.

The relatively high costs and large up-front capital investments required by oil sands projects involve significant assumptions around short-term and long-term crude oil fundamentals, including world supply and demand, North American supply and demand, and price outlook, among many other factors. As oil sands production is long-term in nature, the long-term outlook is significant to a producer's investment decision. In the near-term, the current pricing environment is not expected to impact projected growth from the oil sands region.

We expect that the current crude oil price downturn may result in deferral of some oil sands projects, particularly if the current pricing environment continues throughout 2015 and into 2016. However, we expect that projects already under construction will be finished and enter production. In addition, current production volumes from the oil sands are unlikely to decrease absent an operational upset at one of the oil sands operations. Accordingly, we do not anticipate significant changes in our short-term crude oil volume outlook. Our long-term growth in volumes and additional infrastructure expansion will depend on long-term fundamentals. During this period of uncertainty, we believe our pipeline systems are positioned to capture incremental pipeline capacity needs with lower cost, smaller scale expansions of our large Lakehead, North Dakota and Mid-Continent pipeline systems.

Tight sands oil production in any basin in North America will be comparatively more sensitive to the short-term changes in commodity prices due to the production profile associated with tight sands oil wells. Accordingly, we expect a reduction in the growth rate for North American tight sands and shale oil. We believe that rail will be the source of transportation most directly impacted by any declines in production due to its comparatively higher cost relative to pipeline transportation.

Financial impacts to our pipeline systems, in the event the rate of growth were to slow or volumes were to decline, is muted by our cost-of-service agreements, toll structures and demand to transport crude oil from existing production. We do not believe that the decline in crude oil prices will impact our liquids segment meaningfully in the short-term. However, a long-term decline in crude oil prices could have a more significant impact on future production and our rate of growth.

Expansion Projects

The table and discussion below summarize our commercially secured projects for the Liquids segment, which have been recently placed into service or will be placed into service in future periods:

Projects	Total Estimated Capital Costs	In-Service Date	Funding
	(in millions)		
Line 3 Replacement Program	$2,600	Late 2017	EEP[1]
Sandpiper Project	2,600	Late 2017	Joint[2]
Eastern Access Projects:			
Eastern Access Upsize – Line 6B Expansion	310	Mid-2016	Joint[3]
U.S. Mainline Expansions:			
Chicago Area Connectivity (Line 78)	495	Fourth quarter 2015	Joint[4]
Line 61 (800,000 Bpd capacity)	395	Second quarter 2015	Joint[4]
Line 61 (Additional tankage)	360	Third quarter 2015 – Third quarter 2016	Joint[4]
Line 61 (1,200,000 Bpd capacity)	400	Late 2017	Joint[4]
Line 67	240	Third quarter 2015	Joint[4]

(1) A special committee of independent directors of the Board of Enbridge Management has been established to consider a joint funding agreement with Enbridge.

(2) Jointly funded 62.5% by us and 37.5% by Williston Basin Pipeline LLC, an affiliate of Marathon Petroleum Corp., under the North Dakota Pipeline Company Amended and Restated Limited Liability Company Agreement. Estimated capital costs are presented at 100% before Williston's contributions.

(3) Jointly funded 25% by us and 75% by our General Partner under Eastern Access Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

(4) Jointly funded 25% by us and 75% by our General Partner under Mainline Expansion Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

Line 3 Replacement Program

On March 3, 2014, we and Enbridge announced that shipper support was received to replace portions of the existing 1,031-mile Line 3 pipeline on the Canadian Mainline/Lakehead system between Hardisty, Alberta, Canada and Superior, Wisconsin. Our portion of the Line 3 Replacement Program, referred to as the US L3R Program, includes replacing 358 miles from the U.S./Canadian border at Neche, North Dakota to Superior, Wisconsin. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it supports the safety and operational reliability of the system, enhances flexibility and will allow us and Enbridge to optimize throughput from Western Canada into Superior, Wisconsin.

We are in the process of obtaining the appropriate construction permits within the state of Minnesota for the US L3R Program. The permits require both a Certificate of Need, or Certificate, and an approval of the pipeline's route, or Route Permit, from the Minnesota Public Utilities Commission, or MNPUC. The MNPUC found both the Certificate and Route Permit applications to be complete. The MNPUC has sent the Certificate application to the Administrative Law Judge, or ALJ, for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce held public scoping meetings in August 2015. As a result of the Minnesota Court of Appeals decision for the Sandpiper Project, the ALJ has requested direction on how to proceed with the Certificate process for the US L3R Program. We filed a motion to join the Certificate and Route Permit proceedings, which would enable the MNPUC to rely on the Comparative Environmental Analysis, or CEA, in reaching its decision on both the Certificate and Route Permit applications.

Subject to regulatory and other approvals, the US L3R Program is targeted to be completed in late 2017 at an estimated cost of $2.6 billion. We will recover our costs based on our existing Facilities Surcharge Mechanism, or FSM, with the initial term being 15 years. For purposes of the toll surcharge, the agreement specifies a 30 year recovery of the capital based on a cost-of-service methodology. A special committee of independent directors of the board of Enbridge Management has been established to consider a proposal from our General Partner, on behalf of Enbridge, that would establish joint funding arrangements for the US L3R Program by creating an additional jointly owned series of partnership interests in Enbridge Energy, Limited Partnership, or OLP, similar to the series established for Eastern Access and Mainline Expansion.

Light Oil Market Access Program

We and Enbridge have invested in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant recent developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Projects, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries.

<u>Sandpiper Project</u>

Included in the Light Oil Market Access Program is the Sandpiper Project, which will expand and extend the North Dakota feeder system by 225,000 Bpd to a total of 580,000 Bpd. The proposed expansion will involve construction of an approximate 600-mile pipeline from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 250,000 Bpd of capacity on the twin line between Tioga and Berthold, North Dakota and 225,000 Bpd of capacity on the twin line between Berthold and Clearbrook both with a new 24-inch diameter pipeline, in addition to adding 375,000 Bpd between Clearbrook and Superior with a 30-inch diameter pipeline. The Sandpiper project is expected to cost approximately $2.6 billion.

We are in the process of obtaining both a Certificate and Route Permit from the MNPUC for the Sandpiper Project. On August 3, 2015, the MNPUC issued an order granting a Certificate and a separate order restarting the Route Permit proceedings. On September 14, 2015, the Minnesota Court of Appeals reversed the MNPUC's Certificate order stating that an Environmental Impact Statement must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. As of October 7, 2015, the MNPUC has stayed its August 3, 2015 Certificate order and reopened Certificate proceedings. We and the MNPUC have appealed the Minnesota Court of Appeals decision to the State Supreme Court, and activity continues in the Route Permit proceedings according to MNPUC expectations. Subject to regulatory and other approvals, we estimate that the in-service date for the Sandpiper pipeline project will occur during late 2017.

Marathon Petroleum Corporation, or MPC, has been secured as an anchor shipper for the Sandpiper project. As part of the arrangement, we, through our subsidiary, North Dakota Pipeline Company LLC, or NDPC and Williston Basin Pipeline LLC, or Williston, an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of the Sandpiper Project construction and have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed $1.2 billion in aggregate. In return for funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper.

<u>Eastern Access Projects</u>

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the U.S. Upper Midwest and the Canadian provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. As part of the Light Oil Market Access Program announced in 2012, we announced an expansion project for Line 6B to increase capacity from 500,000 Bpd to 570,000 Bpd and to include: pump station modifications at Griffith, Niles and Mendon; additional modifications at the Griffith and Stockbridge terminals; and breakout tankage at Stockbridge. The expected cost of this expansion is approximately $310 million and will be placed into service in mid-2016. This project is being funded 75% by our General Partner and 25% by us under the Eastern Access Joint Funding Agreement. Within one year of the in-service date, we will have the option to increase our economic interest by up to 15% at cost. The Eastern Access Projects, which includes the Line 6B Expansion project along with the previously completed Line 5 Expansion, Line 62 Expansion and the Line 6B Replacement projects, will cost approximately $2.7 billion.

U.S. Mainline Expansions

In 2012 and 2013, we announced further expansion projects for our mainline pipeline system including: (1) expanding our existing 36-inch diameter Alberta Clipper pipeline, or Line 67; (2) expanding our existing 42-inch diameter Southern Access pipeline, or Line 61; and (3) expanding by constructing Line 78, a twin of the Spearhead North pipeline, or Line 62.

The current scope of the Line 67 pipeline expansion between Neche, North Dakota and the Superior, Wisconsin Terminal consists of two phases. The initial phase increased capacity from 450,000 Bpd to 570,000 Bpd at an estimated capital cost of $220 million. The second phase of the expansion increased capacity from 570,000 Bpd to 800,000 Bpd at an estimated capital cost of approximately $240 million. The initial phase was completed in the third quarter of 2014 and the second phase was completed in July 2015. Both phases of the Line 67 pipeline expansion required only the addition of pumping horsepower, with no pipeline construction, and are subject to regulatory approvals, including an amendment to the current Presidential border crossing permit to allow for the operation of the Line 67 pipeline at its currently-planned operating capacity of 800,000 Bpd. We continue to work with regulatory authorities; however, the timing of the receipt of the amendment to the Presidential border crossing permit to allow for increased flow on the Line 67 pipeline across the border cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment.

In November 2014, several environmental and Native American groups filed a complaint in the United States District Court in Minnesota against the United States Department of State, or DOS. The complaint alleges, among other things, that the DOS is in violation of the National Environmental Policy Act by acquiescing in Enbridge's use of permitted cross border capacity on other lines to achieve the transportation of amounts in excess of the current permitted capacity of Alberta Clipper pending review and approval of Enbridge's application to the DOS to increase the permitted cross border capacity of Alberta Clipper. Enbridge has intervened in the case. A decision at the trial level is not expected before the fourth quarter of 2015.

The scope of the Southern Access expansion, or Line 61 expansion, between Superior, Wisconsin and Flanagan, Illinois also consists of phases. The initial phase to increase the capacity from 400,000 Bpd to 560,000 Bpd was completed in August 2014 at an estimated cost of approximately $160 million. We further expanded the pipeline capacity to 800,000 Bpd in May 2015 at an estimated cost of approximately $395 million. Additional tankage is expected to cost approximately $360 million and will be completed on various dates beginning in the third quarter of 2015 through the third quarter of 2016. In the first quarter of 2015, we, in conjunction with shippers, decided to delay the in-service date of a further expansion tranche to increase the pipeline capacity to 1,200,000 Bpd at an estimated capital cost of approximately $400 million, to align more closely with the currently anticipated in-service date for the Sandpiper project. In October 2015, a portion of this tranche was put into service early to address capacity constraints, increasing pipeline capacity to 950,000 Bpd. The remaining capacity is expected to be in service in late 2017.

Furthermore, as part of the Light Oil Market Access Program announced in 2012, the capacity on our Lakehead System between Flanagan, Illinois, and Griffith, Indiana will be expanded by constructing Line 78, a 79-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62, with an initial capacity of 570,000 Bpd, at an estimated cost of $495 million. The expansion is expected to begin service in the fourth quarter of 2015.

These projects, collectively referred to as the U.S. Mainline Expansion projects, will be undertaken on a cost-of-service basis and will cost approximately $2.3 billion. Furthermore, these projects are jointly funded 75% by our General Partner and at 25% by us, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. Within one year of the in-service date, scheduled for late 2017, we will have the option to increase our economic interest held at that time by up to 15% at cost.

Canadian Eastern Access and Mainline Expansion Projects

The Eastern Access Projects and U.S. Mainline Expansions projects complement Enbridge's strategic initiative of expanding access to new markets in North America for growing production from western Canada and the Bakken Formation. Since October 2011, Enbridge also announced several complementary Eastern Access and Mainline Expansion Projects, which have various targeted in-service dates throughout 2015. Two of these projects include reversal of Enbridge's Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec and an expansion of Enbridge's Line 9 to provide additional delivery capacity within Ontario and Quebec.

The Line 9B reversal and Line 9 capacity expansion projects were approved by the Canadian National Energy Board, or NEB, in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B reversal and Line 9 expansion project. On October 23, 2014, Enbridge responded to the NEB describing Enbridge's rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved Conditions 16 and 18, the two conditions in the NEB's order requiring approval, and Enbridge filed for the Leave to Open, or LTO, which is a prerequisite to allowing the operation of the project. In its February 2015 approval, the NEB also imposed additional obligations on Enbridge that direct it to take a "life-cycle" approach to water crossings and valves, requiring Enbridge to perform ongoing analysis to ensure optimal protection of the area's water resources. On June 18, 2015, the NEB approved the LTO application and issued a separate order imposing further conditions requiring Enbridge to perform hydrostatic tests of selected segments of the pipeline. Enbridge filed its hydrostatic test plan with the NEB on July 23, 2015, which was approved on July 27, 2015. Hydrostatic testing was completed and Enbridge submitted the test results to the NEB in September 2015. On September 30, 2015, the NEB confirmed that the hydrostatic tests successfully met their criteria. Line fill commenced in October 2015, and the pipeline is expected to be placed into service in late November 2015.

Enbridge Market Extensions

One of our key strengths is our relationship with Enbridge. In 2014, Enbridge announced the completion of two major U.S. Gulf Coast market access pipeline projects, the Flanagan South Pipeline and Seaway Crude Pipeline, which are expected to pull more volume through our pipelines and may lead to further expansions of our Lakehead pipeline system. In 2012 Enbridge announced the Southern Access Extension, which, along with the reversal of Line 9A and 9B, will support the increasing supply of light oil from Canada and the Bakken into Patoka, Illinois.

Southern Access Extension

The Southern Access Extension project involves the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, with an initial capacity of 300,000 Bpd, as well as additional tankage and two new pump stations. The additional tankage and pump stations have been placed into service, and the remainder of the project is expected to be placed into service in late 2015. Lincoln Pipeline LLC, or Lincoln, an affiliate of MPC, has a 35% equity interest in the project and will make cash contributions in accordance with the Southern Access Extension's spend profile in proportion to its 35% interest.

Natural Gas

The following tables set forth the operating results of our Natural Gas 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	$ 661.0	$ 1,399.4	$ 2,314.6	$ 4,443.1
Commodity costs	522.7	1,238.2	1,972.4	3,986.7
Segment gross margin	138.3	161.2	342.2	456.4
Operating and administrative	94.1	105.0	264.1	317.5
Goodwill impairment	—	—	246.7	—
Asset impairment	—	—	12.3	—
Depreciation and amortization	39.2	39.5	118.3	113.3
Operating expenses	133.3	144.5	641.4	430.8
Operating income (loss)	5.0	16.7	(299.2)	25.6
Other income	8.9	6.1	20.5	7.1
Net income (loss)	$ 13.9	$ 22.8	$ (278.7)	$ 32.7
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 Natural Gas segment for the three months ended September 30, 2015, decreased $11.7 million as compared with the same period in 2014. The area most affected was segment gross margin, which decreased $22.9 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 $9.9 million, exclusive of $1.6 million gains associated with the assignments of certain natural gas contracts, due to lower non-cash, mark-to-market gains for the three months ended September 30, 2015, as compared with the same period in 2014. These gains 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. On September 1, 2015, two wholly-owned subsidiaries of Midcoast Operating in the Natural Gas segment sold certain natural gas inventories and assigned certain storage agreements, transportation contracts and other arrangements to a third party. We recognized a loss of $9.3 million in connection with this transaction, primarily related to costs to transfer certain fixed-demand storage and transportation obligations to the buyer.

Segment gross margin decreased $8.1 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.

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 in 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 administrative costs decreased $10.9 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.

Other income increased $2.8 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 Natural Gas segment for the nine months ended September 30, 2015, decreased $324.8 million, as compared with the same period in 2014, primarily due to a $246.7 million goodwill impairment charge 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 both recorded during the second quarter. We performed a goodwill impairment analysis after we learned from customers during the second quarter of 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 $246.7 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. 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 decreased $114.2 million for the nine months ended September 30, 2015, as compared with the same period in 2014, primarily due to a net decrease of $63.4 million, exclusive of $1.6 million gains associated with the assignments of certain natural gas contracts, due to non-cash, mark-to-market losses of $53.5 million for the nine months ended September 30, 2015, as compared to gains of $11.5 million for the nine months ended September 30, 2014. These losses in 2015 are primarily related to the reclassification of previously recognized unrealized market-to-market gains as the underlying transactions were settled.

Our segment gross margin was also impacted by decreased margins within our gas marketing function due to price differentials between market centers of approximately $29.5 million for the nine months ended September 30, 2015, when compared to the same period in 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.

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 was primarily attributable to commodity price declines for natural gas and condensate during 2015, 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.

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 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 administrative costs decreased $53.4 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 $5.0 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 $13.4 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 Natural Gas

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 declining 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 price risk through our hedging program. We have hedged over 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 for the Natural Gas segment, which 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 MEP based on our proportionate ownership percentages in Midcoast Operating, which are 48.4% and 51.6%, respectively.

Eaglebine Developments

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 New Gulf Resources, LLC, or 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*.

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 MEP based on our proportionate ownership percentages in Midcoast Operating.

Corporate

Our corporate results consist of interest expense, interest income, allowance for equity during construction 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 Results:				
Operating and administrative expenses	$ 3.3	$ 3.8	$ 10.9	$ 6.9
Operating loss	(3.3)	(3.8)	(10.9)	(6.9)
Interest expense, net	(88.2)	(137.1)	(214.5)	(294.2)
Allowance for equity used during construction	13.7	14.5	54.0	47.8
Other income (expense)	(0.1)	(4.3)	0.2	(4.9)
Income (loss) before income tax expense	(77.9)	(130.7)	(171.2)	(258.2)
Income tax expense	(4.6)	(2.1)	(3.2)	(6.1)
Net loss	$(82.5)	$(132.8)	$(174.4)	$(264.3)

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

The $50.3 million decrease in our net loss for the three months ended September 30, 2015, as compared to the same period in 2014 was primarily attributable to a decrease in interest expense.

The $48.9 million reduction in interest expense was primarily due to the recognition of unrealized losses for hedge ineffectiveness associated with interest rate hedges that were originally set to mature in 2014 and 2016 that we recognized in September 2014. No similar recognition of ineffectiveness occurred in the same period of 2015. For the three and nine months ended September 30, 2014, interest expense increased due to recognition of unrealized losses for hedge ineffectiveness of approximately $62.2 million.

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

The results for corporate activities for the nine months ended September 30, 2015, compared to the same period in 2014, changed for the same reasons as noted in the three month analysis above.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $1.975 billion multi-year senior unsecured revolving credit facility, which we refer to as the Credit Facility, and our $625.0 million credit agreement, which we refer to as the 364-Day Credit Facility. We refer to the

364-Day Credit Facility and the Credit Facility as our Credit Facilities. In addition, we have a credit agreement with EUS, or the EUS 364-day Credit Facility, which provides an additional $750.0 million in liquidity. We access our $1.5 billion commercial paper program primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities. At September 30, 2015, we had approximately $724.6 million in available credit under the terms of our Credit Facilities. For a description of our commercial paper program and our Credit Facilities, refer to Item 1. *Financial Statements*, Note 8. *Debt*.

On July 2, 2015, we amended our 364-Day Credit Facility to extend the revolving credit termination date from July 3, 2015 to July 1, 2016. We further amended the 364-Day Credit Facility to decrease the aggregate commitments from $650.0 million to $525.0 million. On August 7, 2015, we exercised our right to increase the total amount of commitments under our 364-day Credit Facility to $625.0 million.

As set forth in the following table, we had approximately $1.2 billion of consolidated liquidity available to us at September 30, 2015, to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil release on Line 6B.

	EEP	MEP
	(in millions)	
Cash and cash equivalents	$ 94.9	$ 15.6
Total credit available under EEP's Credit Facilities	2,600.0	—
Total credit available under the EUS 364-day Credit Facility	750.0	—
Total credit available under MEP's Credit Agreement	—	810.0
Less: Amounts outstanding under the Credit Facilities[1]	1,885.0	—
Amounts outstanding under the EUS 364-day Credit Facility	—	—
Amounts outstanding under MEP's Credit Agreement	—	420.0
Principal amount of commercial paper outstanding[1]	321.1	—
Letters of credit outstanding	419.3	—
Total	$ 819.5	$405.6

[1] On October 6, 2015, we closed a public offering of senior unsecured notes, for net aggregate proceeds of approximately $1.26 billion, after deducting underwriting discounts and commissions and estimated offering expenses. We used a portion of the net proceeds from this offering to repay a portion of our outstanding commercial paper and to repay any credit facility borrowings that were outstanding. After the offering on a pro-forma basis the total consolidated liquidity is approximately $2.5 billion.

General

Our primary operating cash requirements consist of normal operating expenses, maintenance capital expenditures, distributions to our partners and payments associated with our risk management activities. We expect to fund our current and future short-term cash requirements for these items from our operating cash flows supplemented as necessary by issuances of commercial paper and borrowings on our Credit Facilities. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facilities.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through organic growth and targeted acquisitions. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all. In addition, we intend to sell additional interests in Midcoast Operating to MEP to raise capital over the course of the next several years. Although this is our intent, there is no assurance that any transactions will occur as they are subject to, among other things, obtaining agreement from MEP and its board of directors around the commercial terms of such a sale. When we have attractive growth opportunities in excess of our own capital raising capabilities, the General Partner has provided supplementary funding, or participated directly in projects, to enable us to undertake such opportunities. If in the future we have attractive growth opportunities that exceed capital raising capabilities, we could seek similar arrangements from the General Partner, but there can be no assurance that this funding can be obtained.

As of September 30, 2015, we had a working capital deficit of approximately $1.0 billion and approximately $1.2 billion of liquidity to meet our ongoing operational, investment and financing needs as shown above, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil releases on Line 6B.

Financing Transactions with Affiliates

EUS 364-day Credit Facility

On March 9, 2015, we entered into the EUS Credit Facility. The EUS 364-day Credit Facility is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $750 million, (1) on a revolving basis for a 364-day period and (2) for a 364-day term on a non-revolving basis following the expiration of the revolving period. Loans under the EUS 364-day Credit Facility accrue interest based, at our election, on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. The EUS 364-day Credit Facility terminates on March 7, 2016, and including the option to term the revolving loan for a period of 364-days following the termination date, the credit facility becomes non-revolving thus extending the term to March 6, 2017. There is no outstanding balance as of September 30, 2015 under the EUS 364-day Credit Facility.

The commitment under the EUS 364-day Credit Facility may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to us from the sale by us of (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these activities. We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions will require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. If market conditions change and capital markets become constrained, our ability and willingness to complete future debt and equity offerings may be limited. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. In February 2015, we filed with the SEC a new shelf registration statement, or the 2015 Shelf, on Form S-3 that replaced our prior shelf registration statement which expired in December 2014. The 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

Issuance of Class A Common Units

In March 2015, we sold 8 million Class A common units in an underwritten public offering pursuant to the 2015 Shelf for net proceeds of $288.8 million. The following table presents the net proceeds from our Class A common unit issuances for the current year. The proceeds from the March 2015 offering were used to fund a portion of our capital expansion projects and for general partnership purposes.

2015 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amount)			
March	8,000,000	$36.70	$288.8	$6.0	$294.8

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Series 1 Preferred Unit Amendment

On July 30, 2015, we amended our limited partnership agreement to extend the deferral of distribution payments through June 30, 2018 and to allow repayment of the accumulated deferral amount in equal amounts over a twelve-quarter period beginning in the first quarter of 2019. In addition, the amendment extended the rate reset pricing date to June 30, 2020, and each subsequent five-year anniversary thereafter. The amendment also defers the conversion option date, whereby the holder of the Preferred Units may convert their Series 1 Preferred Units into Class A common units, to on or after June 30, 2018.

The amendment to the Series 1 Preferred Unit has been accounted for as a modification, as the difference in the fair value of the preferred units before and after the modification was insignificant. The remaining unamortized beneficial conversion feature after the amendment will be amortized over an extended period through June 30, 2018.

Joint Funding Arrangements

In order to obtain the required capital to expand our various pipeline systems, we have determined that the required funding would challenge our ability to efficiently raise capital. Accordingly, we have explored numerous options and determined that several joint funding arrangements would provide the best source of available capital to fund the expansion projects.

Joint Funding Arrangement for Eastern Access Projects

The OLP has a series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. Except as described below in *Amendment of OLP Limited Partnership Agreement*, these projects are currently jointly funded by our General Partner at 75% and by us at 25%, respectively. Additionally, within one year of the in-service date, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points.

Our General Partner made equity contributions totaling $119.3 million and $550.5 million to the OLP during the nine months ended September 30, 2015 and 2014, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Joint Funding Arrangement for the U.S. Mainline Expansion

The OLP also has a series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. Except as described below in *Amendment of OLP Limited Partnership Agreement*, these projects are currently jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points.

Our General Partner has made equity contributions totaling $552.9 million and $384.0 million to the OLP for the nine months ended September 30, 2015 and 2014, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Amendment of OLP Limited Partnership Agreement

On July 30, 2015, the partners amended and restated the limited partnership agreement of the OLP, pursuant to which our General Partner will temporarily forego Series EA and ME, collectively, the Series, distributions commencing in the quarter ended June 30, 2015 through the quarter ending March 31, 2016. The General Partner's capital funding contribution requirements for each of those two Series, commencing in August 2015, will be reduced by the amount of its foregone cash distributions from the respective Series, until the earlier of December 31, 2016 and the date aggregate reductions in capital contributions for such Series are equal to the foregone cash distributions for such Series. To the extent that the General Partner's portion of capital contributions prior to December 31, 2016 are insufficient to cover the General Partner's foregone cash distributions for a Series, beginning with the distribution related to the first quarter of 2017 for that Series, we will receive reduced cash distributions by up to 50%, and the General Partner will receive a comparable increase in cash distributions each quarter until the General Partner has received an aggregate amount of contribution reductions and distribution increases equal to the amount of foregone cash distributions.

Cash Requirements

Capital Spending

We incurred capital expenditures of approximately $1.6 billion for the nine months ended September 30, 2015, including $65.8 million of maintenance capital activities and $740.6 million of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. In addition, we incurred $3 million of contributions to fund our joint ventures. At September 30, 2015, we had approximately $1.0 billion 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. We expect to make additional expenditures during the remainder of the year for the acquisition and construction of natural gas and crude oil transportation infrastructure.

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. 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 will increase due to the growth of our pipeline systems and the aging of portions of these systems. Maintenance capital expenditures are expected to be funded by operating cash flows.

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs. We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses.

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. We anticipate funding expansion capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate.

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 our Credit Facilities 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.

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 our estimated maintenance and expansion capital expenditures, net of joint funding, of $1.1 billion for the year ending December 31, 2015. We expect to receive funding of approximately $1 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects, Mainline Expansion Projects and Line 3 Replacement Project. Furthermore, we expect to receive funding of approximately $115 million from MPC based on our joint funding arrangement for the Sandpiper Project. Although we anticipate making these expenditures in 2015, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, regulatory permitting, 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)
Liquids Projects	
Eastern Access Projects	$ 290
U.S. Mainline Expansions	900
Sandpiper	310
Line 3 Replacement	130
Liquids Integrity Program	260
Expansion Capital	120
Maintenance Capital Expenditures	60
	2,070
Less joint funding from:	
General Partner	960
Third parties	115
Liquids Total	**$ 995**
Natural Gas Projects	
Beckville Cryogenic Processing Plant	$ 60
Eaglebine Developments	125
Expansion Capital	65
Maintenance Capital Expenditures	40
	290
Less joint funding from:	
MEP	150
Natural Gas Total	**$ 140**
TOTAL	**$1,135**

Environmental

Lakehead Line 6B Crude Oil Release

During the nine months ended September 30, 2015, our cash flows were affected by the approximate $32.0 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil releases that occurred in 2010 on Line 6B of our Lakehead system.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers during the third quarter 2013 and have since amended our lawsuit, such that it now includes only one carrier. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit. Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of a lawsuit Enbridge filed against one particular insurer and the remaining $18.0 million is awaiting resolution of arbitration, which is not scheduled to occur until the fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance we will prevail in the arbitration. For more information, refer to Item 1. *Financial Statements*, Note 11. *Commitments and Contingencies*.

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 and interest rates and 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 or interest rates.

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at September 30, 2015 for each of the indicated calendar years:

	Notional[(1)]	2015	2016	2017	2018	2019 & Thereafter	Total
				(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	3,168,752	11.8	5.4	—	—	—	17.2
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 purchased	1,969,000	—	—	—	—	—	—
Natural gas – calls written	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 purchased	91,500	—	—	—	—	—	—
NGL – calls written	4,486,600	—	(1.2)	(3.0)	—	—	(4.2)
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		$42.7	$78.5	$ 8.2	$0.1	$0.1	$129.6

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

The following table provides summarized information about the timing and estimated settlement amounts of our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at September 30, 2015 for each of the indicated calendar years:

	Notional	2015	2016	2017	2018	2019	Total[(1)]
				(in millions)			
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	$2,020	$ (0.4)	$ (8.4)	$ (9.6)	$ (7.3)	$(1.8)	$ (27.5)
Pre-issuance hedges	$2,350	(313.0)	(85.3)	(52.7)	(13.4)	—	(464.4)
		$(313.4)	$(93.7)	$(62.3)	$(20.7)	$(1.8)	$(491.9)

(1) Fair values exclude credit valuation adjustment gains of approximately $4.5 million 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	$ 1,054.3	$ 491.7	$ 562.6
Investing activities	(1,566.5)	(2,033.7)	467.2
Financing activities	424.8	1,673.8	(1,249.0)
Net increase (decrease) in cash and cash equivalents	(87.4)	131.8	(219.2)
Cash and cash equivalents at beginning of year	197.9	164.8	33.1
Cash and cash equivalents at end of period	$ 110.5	$ 296.6	$ (186.1)

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

	For the nine months ended September 30, 2015	For the nine months ended September 30, 2014	Variance 2015 vs. 2014
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 36.2	$ 0.9	$ 35.3
Due from General Partner and affiliates	(28.1)	15.3	(43.4)
Accrued receivables	216.2	27.7	188.5
Inventory	0.5	(131.0)	131.5
Current and long-term other assets	(33.6)	(28.7)	(4.9)
Due to General Partner and affiliates	80.5	(23.4)	103.9
Accounts payable and other	(11.5)	(93.1)	81.6
Environmental liabilities	(34.5)	(116.7)	82.2
Accrued purchases	(175.1)	(28.6)	(146.5)
Interest payable	0.3	5.9	(5.6)
Property and other taxes payable	2.7	23.8	(21.1)
Net change in working capital accounts	$ 53.6	$(347.9)	$ 401.5

Operating Activities

Net cash provided by our operating activities increased $562.6 million for the nine months ended September 30, 2015, compared to the same period in 2014, primarily due to:

- Increased cash from net income of $146.7 million, after adjusting for $190.6 million of non-cash items primarily consisting of $246.7 million of goodwill impairment;
- Increased cash from inventory of $131.5 million primarily resulting from lower commodity prices partially offset by seasonal volume increases;
- Increased cash from reduced payments for environmental liabilities of $82.2 million associated with the accrual for the Line 6B crude oil release;
- Increased cash provided by a greater use of accounts payable and other as working capital of $81.6 million resulting from increased operating accruals related to our liquids pipelines;

- Increased cash from net balances due to and due from the General Partner and its affiliates of $60.5 million resulting from delayed payment on amounts due to the General Partner and its affiliates; and
- Net increased cash from accrued receivables and accrued purchases of $42.0 million resulting from lower commodity prices and lower natural gas volumes, offset by decreased sales of our receivables per our Receivables Agreement;

Investing Activities

Net cash used in our investing activities during the nine months ended September 30, 2015 decreased by $467.2 million compared to the same period in 2014 primarily due to decreased cash used for additions to property, plant and equipment, net of construction payables, of $499.6 million related to reduced payments on our construction payables, offset in part by increased cash used for asset acquisitions of 85.0 million due to MEP's acquisition of NGR's midstream assets in February 2015. For further details regarding this acquisition, see Item 1. *Financial Statements*, Note 3. *Acquisitions.*

Financing Activities

Net cash provided by our financing activities decreased $1,249.0 million for the nine months ended September 30, 2015 compared to the same period in 2014 primarily due to the following:

- Decreased cash from net borrowings on the commercial paper program of $1,090.8 million;
- 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 our noncontrolling interest of $342.4 million for ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project;
- Decreased cash from increased repayments of $294.0 million to the General Partner for the A1 Loan. The remaining outstanding balance of $306.0 million was repaid on January 2, 2015; and
- Decreased cash from increased distributions to our limited partners of $75.7 million and to our noncontrolling interest of $97.8 million due to phases of the Eastern Access Project and Mainline Expansion Project being placed into service.

These decreases in net cash provided by our financing activities were partially offset by the following:

- Increased cash from increased net borrowings under our Credit Facility of $755.0 million; and
- Increased cash from our Class A unit issuance, including our General Partner's contributions, of $294.8 million in March 2015. We had no similar issuances in 2014.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

On February 27, 2015, we filed FERC tariff No. 43.16.0, our annual rate adjustment with the FERC for the Facilities Surcharge Mechanism, or FSM, component of the Lakehead system with rates effective April 1, 2015. The FSM allows Lakehead to recover costs associated with particular shipper-approved projects through an incremental cost-of-service based surcharge that is layered on top of the base index rates. The FSM surcharge reflects our projected costs for these shipper-approved projects for 2015 and an adjustment for the difference between estimated and actual costs and throughput for the prior year. The surcharge is applicable to all volumes entering our system from the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

This tariff filing decreased our transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.10 per barrel, to approximately $2.39 per barrel. The tariff filing also decreased our transportation rate for light crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.08 per barrel, to approximately $1.98 per barrel. These decreases were primarily the result of an increase in forecasted 2015 throughput and the use of a nine-month recovery period from April through December rather than a five-month recovery period from August to December that was used for 2014. The shorter recovery period in 2014 was due to a delayed toll filing as a result of negotiations with shippers concerning certain components of the tariff rate structure.

On May 29, 2015, we filed FERC tariff No. 43.17.0 with an effective date of July 1, 2015 for our Lakehead system. We increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

North Dakota System

Effective February 1, 2015, FERC tariff No. 3.6.0 established a new interconnection at Tioga, North Dakota.

Effective April 1, 2015, FERC tariff No. 3.7.0 updated the calculation of the Phase 5 Looping and Phase 6 Mainline surcharges. These surcharges are cost-of-service based surcharges that are adjusted each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing decreased our average transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.44 per barrel, to an average of approximately $1.77 per barrel. The Phase 5 Looping surcharge decreased primarily due to an increase in forecasted throughput, and the Phase 6 Mainline surcharge decreased due to an increase in forecasted throughput and in order to return prior period over-recoveries to shippers.

Effective April 22, 2015, FERC tariff No. 3.8.0 cancelled the transportation rate from Sherwood, North Dakota to Clearbrook, Minnesota as the pipeline no longer provides service from that receipt point.

Effective July 1, 2015, FERC tariff No. 3.10.0 increased base rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000. Additionally, as per the Transportation Services Agreement, or TSA, this tariff adjusted the operating cost charge component of the committed trunkline rates to Berthold, North Dakota to the actual operating costs and throughput volumes for 2014 and the forecasted operating costs and throughput for 2015.

Also effective July 1, 2015, FERC tariff No. 3.11.0 discounted the existing uncommitted rate from Berthold (pump-over), North Dakota to Berthold, North Dakota. The new tariff rate of $0.27 per barrel reflects a rate decrease of $0.556 per barrel.

Bakken System

Effective January 1, 2015, FERC tariff No. 3.2.0 was filed to reflect a change in the international joint rates. In accordance with FERC policy, each of the international joint rates was equal to or less than the sum of the local rates for the component movements from Berthold, North Dakota to Cromer, Manitoba.

Effective July 1, 2015, FERC tariff No. 2.2.0 increased the local rate in compliance with the indexed rate ceiling allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

Also effective July 1, 2015, FERC tariff No. 3.4.1 adjusted the international joint rates in accordance with the TSA that was included in the Petition for Declaratory Order filed on August 26, 2010 in Docket No. OR10-19-000. Additionally, as per the TSA, this tariff adjusted the operating cost charge component of the committed international joint rates to Cromer, Manitoba to the actual operating costs and throughput volumes for 2014 and the forecasted operating costs and throughput for 2015.

Ozark System

Effective July 1, 2015, FERC tariff No. 48.5.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

SUBSEQUENT EVENTS

Credit Facility Extension

On October 23, 2015, we amended our Credit Facility to extend the maturity date from September 26, 2019 to September 26, 2020 except for $175.0 million of commitments that will expire on September 26, 2018.

Senior Notes Offering

On October 6, 2015, we closed a public offering of $1.6 billion of senior unsecured notes, comprising $500 million aggregate principal amount of notes due October 15, 2020, $500 million aggregate principal amount of notes due October 15, 2025 and $600 million aggregate principal amount of notes due October 15, 2045 for net proceeds of approximately $1.575 billion after deducting underwriting discounts and commissions and estimated offering expenses. In connection with the offering, we paid $314.7 million to settle certain pre-issuance hedges. Of that amount, a loss of $78.6 million is expected to be recognized in interest expense in the fourth quarter of 2015 from ineffectiveness. The remaining loss of $236.1 million is expected to be amortized as interest expense over a term of eight to ten years.

Distribution to Partners

On October 30, 2015, the board of directors of Enbridge Management declared a distribution payable to our partners on November 13, 2015. The distribution will be paid to unitholders of record as of November 6, 2015 of our available cash of $258.7 million at September 30, 2015, or $0.5830 per limited partner unit. Of this distribution, $216.0 million will be paid in cash, $41.8 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.9 million will be retained from our General Partner from amounts otherwise distributable to it in respect of its general partner interest and limited partner interest to maintain its 2% general partner interest.

Distribution to Series EA Interests

On October 30, 2015, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay the entire distribution of $76.1 million to us.

Distribution to Series ME Interests

On October 30, 2015, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series ME interests, declared a distribution payable to the holders of the Series ME general and limited partner interests. The OLP will pay the entire distribution of $32.5 million to us.

Distribution from MEP

On October 29, 2015, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to their partners on November 13, 2015. The distribution will be paid to unitholders of record as of November 6, 2015, of MEP's available cash of $16.5 million at September 30, 2015, or $0.3575 per limited partner unit. MEP will pay $7.6 million to their public Class A common unitholders, while $8.9 million in the aggregate will be paid to us with respect to our Class A common units, our subordinated units, and to 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 acting in its capacity as general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of November 6, 2015. Midcoast Operating will pay $25.7 million to us and $27.4 million to MEP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2014, 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 changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each 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 interest rates and commodity prices, as well as to reduce volatility of 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 interest rates or commodity prices.

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted-average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted-average variable rates are based on implied forward rates in the yield curve at September 30, 2015.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value[2] at September 30, 2015	Fair Value[2] at December 31, 2014
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 510	1.53%	$ —	$ (0.2)
Contracts maturing in 2016					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 90	0.55%	$ (0.1)	$ (0.1)
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 500	2.21%	$ (10.5)	$ (12.9)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (9.0)	$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (7.9)	$ (3.3)
Contracts settling prior to maturity					
2015 – Pre-issuance Hedges	Cash Flow Hedge	$1,000	5.48%	$(313.0)	$(258.3)
2016 – Pre-issuance Hedges	Cash Flow Hedge	$ 500	4.21%	$ (85.3)	$ (63.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.69%	$ (52.7)	$ (36.0)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (13.4)	$ (4.9)

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from 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 of approximately $4.5 million and $37.4 million at September 30, 2015 and December 31, 2014, respectively.

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	528,532	$86.11	$45.66	$21.3	$ —	$65.0	$ —
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	779,270	$74.00	$49.08	$19.3	$ —	$ 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 ($0.5) 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 values 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 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 over-the-counter 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)]	(106.2)	(49.8)
A	(128.3)	(129.1)
Lower than A	(139.7)	17.9
	$(374.0)	$(160.9)

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

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

Item 4. Controls and Procedures

We 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 Securities and Exchange Commission, 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 11. *Commitments and Contingencies*, which is incorporated herein by reference.

Item 1A. Risk Factors

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

Enbridge Energy Partners, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: October 30, 2015

By: /s/ Mark A. Maki
Mark A. Maki
President and
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
4.1	Thirteenth Supplemental Indenture dated as of October 6, 2015 between Enbridge Energy Partners, L.P. and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K, filed on October 6, 2015).
4.2	Fourteenth Supplemental Indenture dated as of October 6, 2015 between Enbridge Energy Partners, L.P. and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K, filed on October 6, 2015).
4.3	Fifteenth Supplemental Indenture dated as of October 6, 2015 between Enbridge Energy Partners, L.P. and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K, filed on October 6, 2015).
10.1*	Form of Indemnification Agreement by Enbridge Energy Company, Inc. 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).
10.3	New Lender Supplement, dated as of August 7, 2015, by and among Enbridge Energy Partners, L.P., BNP Paribas and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on August 13, 2015).
10.4	Extension Agreement And Sixth Amendment To Credit Agreement dated as of October 23, 2015 by and among Enbridge Energy Partners, L.P., the lender parties 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 October 27, 2015).
10.5	Incremental Commitment Activation Notice, dated as of August 7, 2015, by and among Enbridge Energy Partners, L.P., BNP Paribas and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on August 13, 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

ENBRIDGE ENERGY COMPANY, INC.

FORM OF INDEMNIFICATION AGREEMENT

This Indemnification Agreement (''Agreement'') is entered into as of [ ] by and between Enbridge Energy Company, Inc. (the ''Company'') and [ ] (''Indemnitee'').

RECITALS

A. The Company is the general partner of Enbridge Energy Partners, L.P. (the ''Partnership'') and, under a delegation of control agreement, has delegated substantially all of its power and authority to manage the Partnership's business and affairs to Enbridge Energy Management, L.L.C. (''Enbridge Management'').

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 Enbridge Management, or director, manager, officer, employee, agent or fiduciary of any subsidiary of the Company or Enbridge Management, or is or was serving at the request of the Company or Enbridge Management 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 Incorporation, its Bylaws, Enbridge Management's Certificate of Formation, Enbridge Management's Amended and Restated Limited Liability Company Agreement, or the charter documents of any subsidiary of the Company or Enbridge Management, in each case as amended, any agreement, any vote of stockholders 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 and/or Enbridge Management maintain 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 and Enbridge Management's directors, if Indemnitee is a director; or of the Company's and Enbridge Management's officers, if Indemnitee is not a director of the Company or Enbridge Management but is an officer; or of the key employees, agents or fiduciaries of the Company or Enbridge Management, 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 Incorporation or Bylaws, or Enbridge Management's Certificate of Formation or Amended and Restated Limited Liability Company, 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 145 of the Delaware General Corporation Law, 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 Enbridge Management or any subsidiary of the Company or Enbridge Management 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.

[ ]

____

By:
Title:
Address:

AGREED TO AND ACCEPTED BY:

Signature: ______________________________
Name:
Address:

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 April 25, 2002, by and between Enbridge Energy Company, Inc. and J. Richard Bird.
2. Indemnification Agreement, dated effective as of January 23, 2003, by and between Enbridge Energy Company, Inc. and Jeffrey A. Connelly.
3. Indemnification Agreement, dated effective as of July 27, 2010, by and between Enbridge Energy Company, Inc. and J. Herbert England.
4. Indemnification Agreement, dated effective as of April 30, 2015, by and between Enbridge Energy Company, Inc. and Leo J. Golden.
5. Indemnification Agreement, dated effective as of January 1, 2015, by and between Enbridge Energy Company, Inc. and Cynthia L. Hansen.
6. Indemnification Agreement, dated effective as of January 30, 2014, by and between Enbridge Energy Company, Inc. and C. Gregory Harper.
7. Indemnification Agreement, dated effective as of March 1, 2014, by and between Enbridge Energy Company, Inc. and D. Guy Jarvis.
8. Indemnification Agreement, dated effective as of July 29, 2013, by and between Enbridge Energy Company, Inc. and Noor S. Kaissi.
9. Indemnification Agreement, dated effective as of April 25, 2002, by and between Enbridge Energy Company, Inc. and E. Chris Kaitson.
10. Indemnification Agreement, dated effective as of April 25, 2002, by and between Enbridge Energy Company, Inc. and Joel W. Kanvik.
11. Indemnification Agreement, dated effective as of April 28, 2008, by and between Enbridge Energy Company, Inc. and Kenneth C. Lanik.
12. Indemnification Agreement, dated effective as of April 25, 2002, by and between Enbridge Energy Company, Inc. and Mark A. Maki.
13. Indemnification Agreement, dated effective as of September 1, 2006, by and between Enbridge Energy Company, Inc. and Stephen J. Neyland.
14. Indemnification Agreement, dated effective as of July 28, 2005, by and between Enbridge Energy Company, Inc. and Jonathan N. Rose.
15. Indemnification Agreement, dated effective as of October 29, 2007, by and between Enbridge Energy Company, Inc. and Allan M. Schneider.
16. Indemnification Agreement, dated effective as of April 30, 2013, by and between Enbridge Energy Company, Inc. and Bradley F. Shamla.
17. Indemnification Agreement, dated effective as of July 22, 2004, by and between Enbridge Energy Company, Inc. and Bruce A. Stevenson.
18. Indemnification Agreement, dated effective as of October 30, 2013, by and between Enbridge Energy Company, Inc. and Valorie J. Wanner.
19. Indemnification Agreement, dated effective as of October 29, 2007, by and between Enbridge Energy Company, Inc. and Dan A. Westbrook.
20. Indemnification Agreement, dated effective as of October 31, 2014, by and between Enbridge Energy Company, Inc. and John K. Whelen.
21. Indemnification Agreement, dated effective as of July 22, 2004, by and between Enbridge Energy Company, Inc. and Leon A. Zupan.

Exhibit 31.1

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

I, Mark A. Maki, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Enbridge 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/ Mark A. Maki

Mark A. Maki
President and Principal Executive Officer
Enbridge Energy Management, L.L.C.
(as delegate of 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 Enbridge 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)
Enbridge Energy Management, L.L.C. (as delegate of 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 Enbridge Energy Partners, L.P. (the ''Partnership''), hereby certifies that the Partnership's 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 the Partnership.

Date: October 30, 2015

By: /s/ Mark A. Maki

Mark A. Maki
President and Principal Executive Officer
Enbridge Energy Management, L.L.C.
(as delegate of 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 Enbridge Energy Partners, L.P. (the ''Partnership''), hereby certifies that the Partnership's 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 the Partnership.

Date: October 30, 2015

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C.
(as delegate of the General Partner)