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 June 30, 2017

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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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 326,517,110 Class A common units outstanding as of July 28, 2017.

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," "consider," "continue," "could," "estimate," "evaluate," "expect," "explore," "forecast," "intend," "may," "opportunity," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) the effectiveness of the various actions we have taken resulting from our strategic review process; (2) changes in the demand for the supply of, forecast data for, and price trends related to crude oil and liquid petroleum, including the rate of development of the Alberta Oil Sands; (3) our ability to successfully complete and finance expansion projects; (4) the effects of competition, in particular, by other pipeline systems; (5) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to whom we sell products; (6) hazards and operating risks that may not be covered fully by insurance, including those related to Line 6B; (7) changes in or challenges to our tariff rates; (8) 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 (9) permitting at federal, state and local level or renewals of rights of way. Any statements regarding sponsor expectations or intentions are based on information communicated to us by Enbridge, but there can be no assurance that these expectations or intentions will not change in the future.

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, 2016, and in any Quarterly Report on Form 10-Q filed thereafter, which are available to the public over the Internet at the U.S. 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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Transportation and other services	$ 569.7	$591.5	$1,149.7	$1,198.6
Transportation and other services – affiliate	26.8	29.8	51.5	52.4
	596.5	621.3	1,201.2	1,251.0
Operating expenses:				
Environmental costs, net of recoveries	3.5	0.1	13.8	17.0
Operating and administrative	84.3	62.6	161.7	124.5
Operating and administrative – affiliate	74.0	71.5	149.7	151.9
Power	66.4	59.7	140.9	132.5
Depreciation and amortization	108.3	104.9	217.1	206.3
Gain on sale of assets (Note 6)	(51.5)	—	(62.1)	—
	285.0	298.8	621.1	632.2
Operating income	311.5	322.5	580.1	618.8
Interest expense, net	(102.8)	(93.3)	(201.7)	(197.8)
Allowance for equity used during construction	10.7	13.3	21.0	25.6
Other income	11.4	0.2	11.4	0.4
Income from continuing operations before income tax	230.8	242.7	410.8	447.0
Income tax benefit (expense)	1.6	(2.0)	0.5	(3.6)
Income from continuing operations	232.4	240.7	411.3	443.4
Loss from discontinued operations, net of tax (Note 6)	(35.4)	(63.0)	(56.8)	(93.3)
Net income	197.0	177.7	354.5	350.1
Less: Net income attributable to:				
Noncontrolling interests	90.6	70.3	158.9	139.1
Series 1 preferred unit distributions	6.5	22.5	29.0	45.0
Accretion of discount on Series 1 preferred units	7.3	1.2	8.5	2.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 92.6	$ 83.7	$ 158.1	$ 163.7
Net income (loss) allocable to common units and i-units:				
Income from continuing operations	$ 104.9	$ 73.7	$ 172.1	$ 118.8
Loss from discontinued operations	(24.2)	(46.0)	(38.0)	(67.0)
Net income allocable to common units and i-units	$ 80.7	$ 27.7	$ 134.1	$ 51.8
Net income (loss) per common unit and i-unit (basic and diluted):				
Income from continuing operations	$ 0.27	$ 0.21	$ 0.46	$ 0.33
Loss from discontinued operations	(0.06)	(0.13)	(0.10)	(0.18)
Net income per common unit and i-unit	$ 0.21	$ 0.08	$ 0.36	$ 0.15
Weighted average common units and i-units outstanding (basic and diluted)	400.1	347.1	376.7	345.9
Distributions paid per limited partner unit	$ 0.350	$0.583	$ 0.933	$ 1.166

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(unaudited; in millions)			
Net income	$197.0	$177.7	$354.5	$ 350.1
Other comprehensive income (loss), net of tax				
Change in unrealized loss on cash flow hedges	(19.4)	(51.5)	(20.3)	(139.1)
Reclassification to earnings of loss on cash flow hedges	10.4	9.8	20.7	19.8
Other comprehensive income (loss), net of tax	(9.0)	(41.7)	0.4	(119.3)
Comprehensive income	188.0	136.0	354.9	230.8
Less:				
Comprehensive income attributable to noncontrolling interests	90.6	70.3	158.9	139.1
Net income attributable to Series 1 preferred unit distributions	6.5	22.5	29.0	45.0
Net income attributable to accretion of discount on Series 1 preferred units	7.3	1.2	8.5	2.3
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 83.6	$ 42.0	$158.5	$ 44.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

	Six months ended June 30,	
	2017	2016
	(unaudited; in millions)	
Series 1 Preferred units:		
Beginning balance	$ 1,191.5	$1,186.8
Redemption of preferred units (Note 11)	(1,200.0)	—
Net income	29.0	45.0
Distribution payable	(29.0)	(45.0)
Accretion of discount on preferred units	8.5	2.3
Ending balance	$ —	$1,189.1
Class D units:		
Beginning balance	$ 2,517.6	$2,517.6
Waiver of Class D units (Note 11)	(2,479.1)	—
Net income	—	77.1
Distributions	(38.5)	(77.1)
Ending balance	$ —	$2,517.6
Class E units:		
Beginning balance	$ 778.2	$ 778.2
Net income	12.7	21.1
Distributions	(16.9)	(21.1)
Ending balance	$ 774.0	$ 778.2
Class A common units:		
Net income	$ 149.7	$ 305.7
Issuance of Class A units (Note 11)	1,200.0	—
Distributions	(267.1)	(305.7)
Sale of noncontrolling interest in subsidiary	28.5	—
Other	0.7	—
Ending balance	$ 1,111.8	$ —
Class B common units:		
Net income	$ 6.4	$ 9.1
Sale of noncontrolling interest in subsidiary	0.9	—
Distributions	(7.3)	(9.1)
Ending balance	$ —	$ —
i-units:		
Beginning balance	$ —	$ 212.6
Net income	(8.9)	(212.6)
Sale of noncontrolling interest in subsidiary	8.9	—
Ending balance	$ —	$ —
Class F units:		
Issuance of Class F units (Note 11)	$ 263.0	$ —
Net income	7.4	—
Distributions	(3.7)	—
Ending balance	$ 266.7	$ —

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL – (continued)

	Six months ended June 30,	
	2017	2016
	(unaudited; in millions)	
Incentive distribution units:		
Beginning balance	$ 495.2	$ 495.0
Waiver of incentive distribution units (Note 11)	(489.9)	—
Net income	—	10.5
Distributions	(5.3)	(10.4)
Ending balance	$ —	$ 495.1
General Partner:		
Beginning balance	$ (666.8)	$ 147.4
Net loss	(9.2)	(47.2)
Waiver of Class D units and incentive distribution units	2,969.0	—
Issuance of Class F units (Note 11)	(263.0)	—
Contributions	24.5	—
Sale of Midcoast assets	(2,126.5)	—
Distributions	(6.9)	(8.6)
Sale of noncontrolling interest in subsidiary	0.8	—
Ending balance	$ (78.1)	$ 91.6
Accumulated other comprehensive loss:		
Beginning balance	$ (339.3)	$ (370.0)
Changes in fair value of derivative financial instruments reclassified to earnings	20.7	19.8
Changes in fair value of derivative financial instruments recognized in other comprehensive loss	(20.3)	(139.1)
Ending balance	$ (338.9)	$ (489.3)
Noncontrolling interests:		
Beginning balance	$ 3,846.1	$3,944.5
Capital contributions	1,305.0	63.4
Sale of noncontrolling interest in subsidiary	411.0	—
Acquisition of noncontrolling interest in subsidiary	(360.3)	—
Sale of Midcoast assets	(296.6)	—
Net income	158.9	139.1
Distributions to noncontrolling interests	(219.0)	(15.2)
Ending balance	$ 4,845.1	$4,131.8
Total partners' capital at end of period	$ 6,580.6	$8,714.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30,	
	2017	2016
	(unaudited; in millions)	
Operating activities:		
Net income from continuing operations	$ 411.3	$ 443.4
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	217.1	206.3
Derivative fair value net (gains) losses	(0.8)	10.2
Environmental costs, net of recoveries	14.2	15.7
Equity earnings from investments in joint ventures	(6.4)	—
Gain on sale of assets	(62.1)	—
Allowance for equity used during construction	(21.0)	(25.6)
Amortization of debt issuance and hedging costs	18.6	20.0
Asset impairment	—	0.4
Other	(2.4)	5.4
Changes in operating assets and liabilities	(353.7)	(232.1)
Net cash provided by operating activities	214.8	443.7
Net cash (used in) provided by discontinued operations	(171.1)	102.8
Investing activities:		
Capital expenditures	(228.9)	(637.9)
Changes in restricted cash	13.6	11.1
Proceeds from the sale of net assets	314.0	—
Proceeds from the sale of Midcoast assets	1,310.0	—
Investments in joint ventures	(1,556.7)	—
Other	(2.5)	(2.3)
Net cash used in investing activities	(150.5)	(629.1)
Net cash used in discontinued operations	(14.0)	(31.0)
Financing activities:		
Redemption of Series 1 preferred units	(1,200.0)	—
Payment of Series 1 preferred unit dividends	(357.3)	—
Net proceeds from Class A unit issuances	1,224.5	—
Distributions to partners	(345.7)	(399.0)
Repayments to General Partner and affiliates	(1,829.4)	—
Borrowings from General Partner and affiliates	1,500.0	—
Net (repayments) borrowings under credit facilities	(865.0)	630.0
Net commercial paper borrowings (repayments)	675.7	(131.8)
Acquisition of noncontrolling interest in subsidiary	(360.3)	—
Sale of noncontrolling interest in subsidiary	450.1	—
Contributions from noncontrolling interests	1,285.0	81.9
Distributions to noncontrolling interests	(219.0)	—
Other	(0.5)	(0.8)
Net cash (used in) provided by financing activities	(41.9)	180.3
Net cash (used in) provided by discontinued operations	229.0	(81.7)
Net increase (decrease) in cash and cash equivalents	66.3	(15.0)
Cash disposed as part of the Midcoast sale	(51.3)	—
Cash and cash equivalents at beginning of year – continuing operations	101.3	130.1
Cash and cash equivalents at beginning of year – discontinued operations	7.4	18.0
Cash and cash equivalents at end of period	123.7	133.1
Cash and cash equivalents at end of period – continuing operations	123.7	125.0
Cash and cash equivalents at end of period – discontinued operations	—	8.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2017	December 31, 2016
	(unaudited; in millions, except per unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 123.7	$ 101.3
Restricted cash	—	13.6
Receivables, trade and other	63.6	6.0
Due from General Partner and affiliates	98.6	88.4
Accrued receivables	94.0	18.8
Other current assets	41.3	34.3
Current assets related to discontinued operations	—	138.6
	421.2	401.0
Property, plant and equipment, net	12,631.9	12,608.2
Equity investments in joint ventures	1,563.1	—
Other assets, net	51.2	118.8
Assets held for sale	—	206.8
Non-current assets related to discontinued operations	—	4,775.3
Total Assets	$14,667.4	$18,110.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and other	$ 353.1	$ 347.7
Due to General Partner and affiliates	38.7	175.2
Interest payable	88.7	90.1
Environmental liabilities	23.6	99.8
Property and other taxes payable	77.4	89.6
Current portion of long-term debt	400.0	—
Current liabilities related to discontinued operations	—	299.8
	981.5	1,102.2
Long-term debt	6,479.3	7,065.9
Loans from General Partner and affiliate	420.6	750.0
Due to General Partner and affiliates	—	328.3
Other long-term liabilities	205.4	196.9
Non-current liabilities related to discontinued operations	—	844.3
	8,086.8	10,287.6
Commitments and contingencies		
Partners' capital:		
Series 1 preferred units (48,000,000 authorized and issued at December 31, 2016)	—	1,191.5
Class D units (66,100,000 authorized and issued at December 31, 2016)	—	2,517.6
Class E units (18,114,975 authorized and issued at June 30, 2017 and December 31, 2016)	774.0	778.2
Class A common units (326,517,110 and 262,208,428 outstanding at June 30, 2017 and December 31, 2016, respectively)	1,111.8	—
Class B common units (7,825,500 authorized and issued at June 30, 2017 and December 31, 2016)	—	—
i-units (85,620,914 and 81,857,168 authorized and issued at June 30, 2017 and December 31, 2016, respectively)	—	—
Class F units (1,000 authorized and issued at June 30, 2017)	266.7	—
Incentive distribution units (1,000 authorized and issued at December 31, 2016)	—	495.2
General Partner	(78.1)	(666.8)
Accumulated other comprehensive loss	(338.9)	(339.3)
Total Enbridge Energy Partners, L.P. partners' capital	1,735.5	3,976.4
Noncontrolling interests	4,845.1	3,543.2
Noncontrolling interests – discontinued operations	—	302.9
Total partners' capital	6,580.6	7,822.5
Total Liabilities and Partners' capital	$14,667.4	$18,110.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. GENERAL

The terms ''we'', ''our'', ''us'' and ''Enbridge Energy Partners'' as used in this report refer collectively to Enbridge Energy Partners, L.P. and its subsidiaries unless the context suggests otherwise. Those terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge Energy Partners.

Nature of Operations

We, together with our consolidated subsidiaries, provide crude oil and liquid petroleum gathering, transportation, and storage services. On June 28, 2017, we sold all of our ownership interest in our Midcoast gas gathering and processing business to our General Partner (the Midcoast sale). The sale of this ownership interest represents a strategic shift in our business and meets the criteria for classification as discontinued operations and as a result, the results of operations, cash flows and financial position of our natural gas business for the current and prior periods are reflected as discontinued operations. For further information refer to Note 6 *Dispositions and Discontinued Operations.*

Basis of Presentation

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. They do not include all the information and notes required by U.S. GAAP for annual consolidated financial statements and should therefore be read in conjunction with our annual consolidated financial statements and notes presented in our Annual Report on Form 10-K for the year ended December 31, 2016. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, necessary to present fairly our financial position, results of operations and cash flows for the interim periods reported. These interim consolidated financial statements follow the same significant accounting policies as those included in our annual consolidated financial statements for the year ended December 31, 2016, except for the adoption of new standards.

Our operations and earnings for interim periods can be affected by seasonal fluctuations in the supply of and demand for crude oil, as well as other factors such as the timing and completion of our construction projects, the effect of environmental costs and related insurance recoveries on our Lakehead system, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value and may not be indicative of annual results.

2. FUTURE ACCOUNTING POLICY CHANGES

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board (FASB) believes will result in more timely recognition of such losses. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019 and is to be applied using a modified retrospective approach.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the consolidated statements of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as

2. FUTURE ACCOUNTING POLICY CHANGES – (continued)

well as the right to direct the use of the asset. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

Revenues from Contracts with Customers

ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. We have tentatively decided to adopt the new revenue standard using the modified retrospective method.

We have reviewed a sample of our revenue contracts in order to evaluate the effect of the new standard on our revenue recognition practices. Based on the our initial assessment, estimates of variable consideration which will be required under the new standard for certain contracts may result in changes to the pattern or timing of revenue recognition for those contracts. While we have not yet completed the assessment, we do not expect these changes to have a material impact on revenues or earnings (loss). We are currently developing processes to generate the disclosures required under the new standard.

3. NET INCOME PER LIMITED PARTNER UNIT

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions, except per unit amounts)			
Continuing operations:				
Net income	$ 232.4	$ 240.7	$ 411.3	$ 443.4
Less: Net income attributable to:				
Noncontrolling interest	101.8	87.3	177.7	165.4
Series 1 preferred unit distributions	6.5	22.5	29.0	45.0
Accretion of discount on Series 1 preferred units	7.3	1.2	8.5	2.3
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P. – continuing operations	116.8	129.7	196.1	230.7
Distributions:				
Incentive distributions[(1)]	(3.7)	(5.2)	(7.4)	(10.4)
Distributed earnings attributed to our General Partner	(3.2)	(5.3)	(6.4)	(10.5)
Distributed earnings attributed to Class D and Class E units	(6.4)	(49.1)	(12.7)	(98.2)
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(13.3)	(59.6)	(26.5)	(119.1)
Total distributed earnings attributed to our common units and i-units	(146.9)	(202.9)	(293.3)	(404.6)
Total distributed earnings	(160.2)	(262.5)	(319.8)	(523.7)
Overdistributed earnings	$ (43.4)	$(132.8)	$(123.7)	$(293.0)
Discontinued operations:				
Net loss	$ (35.4)	$ (63.0)	$ (56.8)	$ (93.3)
Less: Net loss attributable to:				
Noncontrolling interest	(11.2)	(17.0)	(18.8)	(26.3)
Net loss attributable to general and limited partner interests in Enbridge Energy Partners, L.P. – discontinued operations	(24.2)	(46.0)	(38.0)	(67.0)
Weighted average common units and i-units outstanding	400.1	347.1	376.7	345.9

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions, except per unit amounts)			
Basic and diluted earnings per unit:				
Distributed earnings per common unit and i-unit – continuing operations[2]	$ 0.37	$ 0.58	$ 0.78	$ 1.17
Overdistributed earnings per common unit and i-unit[3]	(0.10)	(0.37)	(0.32)	(0.84)
Net income per common unit and i-unit (basic and diluted) – continuing operations[4]	$ 0.27	$ 0.21	$ 0.46	$ 0.33
Net loss per common unit and i-unit (basic and diluted) – discontinued operations[4]	$(0.06)	$(0.13)	$(0.10)	$(0.18)
Net income per common unit and i-unit (basic and diluted)	$ 0.21	$ 0.08	$ 0.36	$ 0.15

(1) For the three and six months ended June 30, 2017, Class D units and IDUs were not entitled to distributions as the wholly-owned subsidiary of our General Partner irrevocably waived its rights associated with the Class D and IDUs; for the three and six months ended June 30, 2017, incentive distributions were made to Class F units. For the three and six months ended June 30, 2016, incentive distributions were made to IDUs and Class D units.

(2) 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.

(3) 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.

(4) For the three months ended June 30, 2017, there were no units excluded from the if-converted method of calculating diluted earnings per share. For the six months ended June 30, 2017 and the three and six months ended June 30, 2016, 43,201,310 anti-dilutive Preferred 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 six months ended June 30, 2017, 66,100,000 of Class D units were excluded from the if-converted method of calculating diluted earnings per unit as the General Partner irrevocably waived all of its rights associated with the Class D units effective April 27, 2017. For the three and six months ended June 30, 2016, 66,100,000 anti-dilutive Class D units were excluded from the if-converted method of calculating diluted earnings per unit.

Simplification of Incentive Distributions

On April 27, 2017, a wholly-owned subsidiary of our General Partner irrevocably waived all of its rights associated with its 66.1 million Class D units and its 1,000 incentive distribution units (IDUs) in exchange for the issuance of 1,000 Class F units. The irrevocable waiver (the Waiver) is effective with respect to distributions declared with a record date after April 27, 2017. The Class F units are entitled to receive an incentive distribution for amounts distributed in excess of the Minimum Quarterly Distribution as described in the following table:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner and Class F Units [1]	Percentage Distributed to Limited Partners
Minimum Quarterly Distribution	Up to $0.295	2%	98%
First Target Distribution	> $0.295 to $0.35	15%	85%
Over First Target Distribution	> $0.35	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 Class F Units.

4. SEGMENT INFORMATION

	Three months ended June 30, 2017			
	Liquids	Natural Gas[1]	Other	Consolidated[2]
	(in millions)			
Operating revenues:[3]				
Transportation and other services	$596.5	$ —	$ —	$ 596.5
	596.5	—	—	596.5
Operating expenses:				
Environmental costs, net of recoveries	3.5	—	—	3.5
Operating and administrative	153.5	—	4.8	158.3
Power	66.4	—	—	66.4
Depreciation and amortization	108.3	—	—	108.3
Gain on sale of assets	(51.5)	—	—	(51.5)
	280.2	—	4.8	285.0
Operating income (loss)	$316.3	$ —	$(4.8)	$ 311.5
Interest expense, net				(102.8)
Allowance for equity used during construction				10.7
Other income[4]				11.4
Income from continuing operations before income tax benefit				230.8
Income tax benefit				1.6
Income from continuing operations				232.4
Income (loss) from discontinued operations	—	(41.4)	6.0	(35.4)
Net income				$ 197.0

(1) The operating results of our Natural Gas segment are included in discontinued operations as a result of the Midcoast sale to our General Partner. For further information refer to Note 6 *Dispositions and Discontinued Operations.*

(2) Certain costs that are not allocated to individual segments, including Other, interest expense, allowance for equity used during construction, and income taxes are included in the consolidated total.

(3) There were no intersegment revenues for the three months ended June 30, 2017.

(4) Other income includes our equity income for our Liquids segment from our investment in the Bakken Pipeline System.

	Three months ended June 30, 2016			
	Liquids	Natural Gas[1]	Other	Consolidated[2]
	(in millions)			
Operating revenues:[3]				
Transportation and other services	$621.3	$ —	$ —	621.3
	621.3	—	—	621.3
Operating expenses:				
Environmental costs, net of recoveries	0.1	—	—	0.1
Operating and administrative	132.1	—	2.0	134.1
Power	59.7	—	—	59.7
Depreciation and amortization	104.9	—	—	104.9
	296.8	—	2.0	298.8
Operating income (loss)	$324.5	$ —	$(2.0)	$322.5
Interest expense, net				(93.3)
Allowance for equity used during construction				13.3
Other income				0.2
Income from continuing operations before income tax expense				242.7
Income tax expense				(2.0)
Income from continuing operations				240.7
Loss from discontinued operations	—	(53.5)	(9.5)	(63.0)
Net income				$177.7

(1) The operating results of our Natural Gas segment are included in discontinued operations as a result of the Midcoast sale to our General Partner. For further information refer to Note 6 *Dispositions and Discontinued Operations.*

(2) Certain costs that are not allocated to individual segments, including Other, interest expense, allowance for equity used during construction, and income taxes are included in the consolidated total.

(3) There were no intersegment revenues for the three months ended June 30, 2016.

4. SEGMENT INFORMATION – (continued)

	Six months ended June 30, 2017			
	Liquids	Natural Gas[1]	Other	Consolidated[2]
	(in millions)			
Operating revenues:[3]				
Transportation and other services	$1,201.2	$ —	$ —	$1,201.2
	1,201.2	—	—	1,201.2
Operating expenses:				
Environmental costs, net of recoveries	13.8	—	—	13.8
Operating and administrative	304.0	—	7.4	311.4
Power	140.9	—	—	140.9
Depreciation and amortization	217.1	—	—	217.1
Gain on sale of asset	(62.1)	—	—	(62.1)
	613.7	—	7.4	621.1
Operating income (loss)	$ 587.5	$ —	$(7.4)	$ 580.1
Interest expense, net				(201.7)
Allowance for equity used during construction				21.0
Other income[4]				11.4
Income from continuing operations before income tax benefit				410.8
Income tax benefit				0.5
Income from continuing operations				411.3
Loss from discontinued operations	$ —	$(51.1)	$(5.7)	$ (56.8)
Net income				$ 354.5

(1) The operating results of our Natural Gas segment are included in discontinued operations as a result of the Midcoast sale to our General Partner. For further information refer to Note 6 *Dispositions and Discontinued Operations*.

(2) Certain costs that are not allocated to individual segments, including Other, interest expense, allowance for equity used during construction, and income taxes are included in the consolidated total.

(3) There were no intersegment revenues for the six months ended June 30, 2017.

(4) Other income includes our equity income for our Liquids segment from our investment in the Bakken Pipeline System.

	Six months ended June 30, 2016			
	Liquids	Natural Gas[1]	Other	Consolidated[2]
	(in millions)			
Operating revenues:[3]				
Transportation and other services	$1,251.0	$ —	$ —	$1,251.0
	1,251.0	—	—	1,251.0
Operating expenses:				
Environmental costs, net of recoveries	17.0	—	—	17.0
Operating and administrative	269.3	—	7.1	276.4
Power	132.5	—	—	132.5
Depreciation and amortization	206.3	—	—	206.3
	625.1	—	7.1	632.2
Operating income (loss)	$ 625.9	$ —	$ (7.1)	$ 618.8
Interest expense, net				(197.8)
Allowance for equity used during construction				25.6
Other income				0.4
Income from continuing operations before income tax expense				447.0
Income tax expense				(3.6)
Income from continuing operations				443.4
Loss from discontinued operations	—	(76.3)	(17.0)	(93.3)
Net income				$ 350.1

(1) The operating results of our Natural Gas segment are included in discontinued operations as a result of the Midcoast sale to our General Partner. For further information refer to Note 6 *Dispositions and Discontinued Operations.*

(2) Certain costs that are not allocated to individual segments, including Other, interest expense, allowance for equity used during construction, and income taxes are included in the consolidated total.

(3) There were no intersegment revenues for the six months ended June 30, 2016.

4. SEGMENT INFORMATION – (continued)

Total Assets	June 30, 2017	December 31, 2016[(1)]
Liquids	$14,661.5	$13,030.5
Natural Gas	—	—
Other	5.9	165.6
Total	$14,667.4	$13,196.1

(1) Comparative information excludes assets from discontinued operations. See Note 6 *Dispositions and Discontinued Operations.*

5. REGULATORY MATTERS

Regulatory Accounting

Due to over or under recovery adjustments made in accordance with the Federal Energy Regulatory Commission (FERC), authoritative guidance and our cost-of-service recovery model, 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. These regulatory assets and liabilities are amortized on a straight-line basis over a one-year recovery period. Our over and under recovery revenue adjustments and net regulatory asset amortization for the three and six months ended June 30, 2017 and 2016 are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Net regulatory asset (liability) balance at beginning of period	$(34.1)	$31.2	$ 11.9	$ 29.9
Current period (over) under recovery revenue adjustments	12.0	5.9	(27.0)	13.6
Amortization of prior year regulatory asset	(1.6)	(7.8)	(8.6)	(14.2)
Net regulatory asset (liability) balance at end of period	$(23.7)	$29.3	$(23.7)	$ 29.3

6. DISPOSITIONS AND DISCONTINUED OPERATIONS

Dispositions

During the second quarter of 2017, we sold unnecessary pipe related to the Sandpiper project for cash proceeds of approximately $97.6 million. A gain on disposal of $51.5 million before tax was included in ‘‘Gain on sale of assets’’ on our consolidated statements of income. These assets were part of our Liquids segment.

On March 1, 2017, we completed the sale of the Ozark Pipeline System to a subsidiary of MPLX LP for cash proceeds of approximately $219.6 million, including reimbursement costs. A gain on disposal of $10.6 million before tax was included in ‘‘Gain on sale of assets’’ on our consolidated statements of income. These assets were part of our Liquids segment.

Discontinued Operations

Sale of Natural Gas Business

On June 28, 2017, we completed the sale of all of our ownership interest in our Midcoast gas gathering and processing business to our General Partner for $2.26 billion, which included cash consideration of $1.31 billion and outstanding indebtedness at Midcoast Energy Partners, L.P. (MEP) of $953 million. This sale included our 48.4% limited partnership interest in Midcoast Operating, L.P., our 51.9% limited partnership interest in MEP, and our 100% interest in Midcoast Holdings, L.L.C., MEP’s general partner. We recorded no gain or loss on the sale as this transaction was between entities under common control of Enbridge. The carrying value of the net assets sold was $4.29 billion. As a result of the transaction, partners’ capital decreased by $2.13 billion, all of which was allocated to the General Partner’s capital account. Noncontrolling interest in MEP of $296.6 million was eliminated.

6. DISPOSITIONS AND DISCONTINUED OPERATIONS – (continued)

The following table presents the operating results from discontinued operations of our Midcoast gas gathering and processing business, which have been segregated from our continuing operations in our consolidated statements of income:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Operating revenues:				
Commodity sales	$559.3	$379.4	$1,085.0	$757.2
Commodity sales – affiliate	3.3	1.4	9.4	6.6
Transportation and other services	24.5	46.8	66.7	95.7
	587.1	427.6	1,161.1	859.5
Operating expenses:				
Commodity costs	496.8	350.5	968.2	685.9
Commodity costs – affiliate	25.7	8.5	42.1	21.2
Operating and administrative	28.3	40.0	64.7	74.8
Operating and administrative – affiliate	35.0	38.9	68.7	76.8
Depreciation and amortization	37.1	40.0	74.5	79.5
Asset impairment	—	10.6	—	10.6
	622.9	488.5	1,218.2	948.8
Operating loss	(35.8)	(60.9)	(57.1)	(89.3)
Interest expense, net	(9.5)	(8.1)	(17.4)	(16.5)
Other income	10.4	6.5	18.6	13.9
Loss before income tax expense	(34.9)	(62.5)	(55.9)	(91.9)
Income tax expense	(0.5)	(0.5)	(0.9)	(1.4)
Net loss from discontinued operations	$ (35.4)	$ (63.0)	$ (56.8)	$ (93.3)

The following table presents the major classes of assets and liabilities for discontinued operations of our Midcoast gas gathering and processing business as presented in the consolidated statements of financial position:

	December 31, 2016
Current assets related to discontinued operations:	
Cash and cash equivalents	$ 7.4
Restricted cash	11.0
Receivables, trade and other, net of allowance for doubtful accounts	8.5
Due from General Partner and affiliates	2.1
Accrued receivables	20.8
Inventory	28.1
Other current assets	60.7
	$ 138.6
Non-current assets related to discontinued operations:	
Property, plant and equipment, net	$4,114.5
Equity investments in joint ventures	360.7
Intangible assets, net	251.8
Other assets, net	48.3
	$4,775.3

6. DISPOSITIONS AND DISCONTINUED OPERATIONS – (continued)

	December 31, 2016
Current liabilities related to discontinued operations:	
Accounts payable and other	$ 66.9
Due to General Partner and affiliates	38.8
Environmental liabilities	0.1
Accrued purchases	171.8
Property and other taxes payable	17.2
Interest payable	5.0
	$299.8
Non-current liabilities related to discontinued operations:	
Long-term debt	$818.5
Other long-term liabilities	25.8
	$844.3

7. VARIABLE INTEREST ENTITIES

Enbridge Holdings (DakTex) L.L.C.

On April 27, 2017, we finalized a joint funding arrangement with our General Partner with respect to our equity investment in the Bakken Pipeline System, held through our investment subsidiary, Enbridge Holdings (DakTex) L.L.C. (DakTex). DakTex is now owned 75% by our General Partner and 25% by us. DakTex owns a 75% equity interest in MarEn Bakken Company LLC (MarEn). For more information regarding our equity investment, refer to Note 8. *Equity Investments in Joint Ventures*.

DakTex is considered a variable interest entity (VIE) consolidated by us. We have authority as managing member to exclusively manage the business and affairs of DakTex, subject to certain protective voting rights and are subject to removal as managing member only upon certain fundamental changes. We are the primary beneficiary of Daktex because (i) as the managing partner we have the power to direct the activities of DakTex that most significantly impact its economic performance; and (ii) we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to DakTex.

DakTex does not have any liabilities. Its sole asset is its investment in MarEn. At June 30, 2017, the carrying amount of DakTex's investment in MarEn was $1,544.3 million.

8. EQUITY INVESTMENTS IN JOINT VENTURES

The following table presents our equity investment in a joint venture and ownership interest in MarEn.

	Ownership Interest	June 30, 2017	December 31, 2016
		(in millions)	
MarEn Bakken Company LLC	75.0%	$1,563.1	$—

On February 15, 2017, our joint venture with Marathon Petroleum Corporation (MPC), MarEn, closed its acquisition of the Bakken Pipeline System with Bakken Holdings Company LLC (Bakken Holdings), an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners L.P., to acquire a 49% equity interest in Bakken Pipeline Investments LLC (BPI). BPI owns 75% of the Bakken Pipeline System. Under this arrangement, we and MPC indirectly hold 75% and 25%, respectively, of MarEn's 49% interest in BPI. The purchase price of our effective 27.6% interest in the Bakken Pipeline System was $1.5 billion.

8. EQUITY INVESTMENTS IN JOINT VENTURES – (continued)

The Bakken Pipeline System was placed into service on June 1, 2017, which consists of the Dakota Access Pipeline (DAPL) and the Energy Transfer Crude Oil Pipeline (ETCOP). It connects the prolific Bakken formation in North Dakota to markets in eastern Petroleum Administration for Defense Districts (PADD II) and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost. For further details regarding our funding arrangement, refer to Note 14 *Related Party Transactions*.

We account for our investment in MarEn under the equity method of accounting. For the six months ended June 30, 2017, we recognized $6.4 million in "Other income" in our consolidated statements of income representing our equity earnings for this investment, net of amortization of the purchase price basis difference.

Our equity investment includes the unamortized excess of the purchase price over the underlying net book value (basis difference), of the investees' assets at the purchase date, which is comprised of $14.4 million in goodwill and $931.4 million in amortizable assets included within the Liquids segment. We amortized $2.9 million for the six months ended June 30, 2017, which was recorded as a reduction to equity earnings.

9. DEBT

Credit Facilities

	Maturity Dates	Total Facilities	Draws[1]	Available
		(in millions)		
Enbridge Energy Partners, L.P.	2019 – 2020	$2,625.0	$1,535.0	$1,090.0

(1) Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility and excludes the EUS 364-day Credit Facility

In addition to the committed credit facilities noted in the above table, we also have a $175.0 million (December 31, 2016 — $175.0 million) of uncommitted letter of credit, of which $87.6 million (December 31, 2016 — $70.9 million) were unutilized as at June 30, 2017.

Under our multi-year senior unsecured revolving credit facility and our 364-day revolving credit agreement, together referred to as the Credit Facilities, we had net repayments of approximately $865.0 million during the period ended June 30, 2017, which includes gross borrowings of $8.1 billion and gross repayments of $9.0 billion.

Under our commercial paper program, we had net borrowings of approximately $675.7 million during the period ended June 30, 2017, which includes gross borrowings of $4.6 billion and gross repayments of $3.9 billion.

Under our credit agreement with EUS, an affiliate of Enbridge and the owner of our General Partner, or the EUS 364-day Credit Facility, we had net repayments of approximately $329.4 million during the period ended June 30, 2017, which includes gross borrowings of $443.6 million and gross repayments of $773.0 million.

On April 27, 2017, our Board of Directors finalized the joint funding arrangement with our General Partner with respect to our investment in the Bakken Pipeline System, held through our subsidiary, DakTex. As part of the transaction, DakTex distributed approximately $1.14 billion to us. We used these distribution proceeds plus additional borrowings of $0.4 billion from our existing EUS 364-day Credit Facility to repay the $1.5 billion outstanding under our unsecured revolving 364-day credit agreement with EUS (the EUS Credit Agreement). We terminated the EUS Credit Agreement subsequent to the repayment. For further information on distribution from our General Partner, refer to Note 14 *Related Party Transactions*.

On June 30, 2017, we extended our 364-day revolving credit facility termination date. The termination date was extended to June 29, 2018, which has a term out option that could extend maturity of outstanding borrowings to June 28, 2019, and capacity remains at $625 million. The 364-day Credit Facility is through a syndicate of third party lenders.

As at June 30, 2017, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $1,468.7 million (December 31, 2016 — $1,657.6 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

9. DEBT – (continued)

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

At June 30, 2017, we had approximately $1,090.0 million of unutilized commitments under the terms of our Credit Facilities and the EUS 364-day Credit Facility.

Debt Covenants

We and our consolidated subsidiaries were in compliance with the terms of our financial covenants under our consolidated debt agreements as at June 30, 2017.

On June 5, 2017, we entered into amendments with the lenders of each of our Credit Facilities and the EUS 364-day Credit Facility. These agreements eliminated certain covenants related to MEP and its subsidiaries and were effective June 28, 2017.

Fair Value of Debt Obligations

The carrying amounts of our outstanding commercial paper, borrowings under our Credit Facilities, and the EUS 364-day Credit Facility approximate their fair values at June 30, 2017 and December 31, 2016, 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 EUS 364-day Credit Facility are included with our long-term debt obligations above since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair value of our fixed-rate debt obligations was $6.2 billion and $6.5 billion at June 30, 2017 and December 31, 2016, 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.

10. NONCONTROLLING INTERESTS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Eastern Access Interests	$ 36.8	$ 53.2	$ 76.3	$104.7
U.S. Mainline Expansion Interests	35.8	34.1	69.2	60.7
North Dakota Pipeline Company Interests	18.4	—	16.8	—
Line 3 Replacement Interests	6.0	—	10.6	—
Enbridge Holdings (DakTex) L.L.C. Interests	4.8	—	4.8	—
Midcoast Energy Partners, L.P. – Discontinued Operations	(11.2)	(17.0)	(18.8)	(26.3)
Total	$ 90.6	$ 70.3	$158.9	$139.1

On April 27, 2017, we finalized the previously announced joint funding arrangement with our General Partner for our investment in the Bakken Pipeline System. Our equity investment in MarEn is held by our consolidated subsidiary, DakTex. Under the terms of the agreement, our General Partner contributed approximately $1.14 billion in exchange for Class A units in DakTex to obtain its 75% ownership interest while we retain the remaining 25%. Noncontrolling interests represent our General Partner's 75% interest. For further details refer to Note 14 *Related Party Transactions*.

On June 28, 2017, we completed the Midcoast sale to our General Partner, reducing our noncontrolling interest in MEP to nil upon the closing of the sale.

On January 26, 2017, we entered into a joint funding arrangement with our General Partner for the U.S. Line 3 Replacement Program (U.S. L3R Program). Under the term of the arrangement, our General Partner will fund 99%

10. NONCONTROLLING INTERESTS – (continued)

and we will fund 1% of the capital costs of the U.S. L3R Program. The carrying amount of our 99% interest in the project at the transaction date was $411.0 million and was recorded as an increase to noncontrolling interest. The $39.1 million difference between the cash received and the carrying amount was recorded as an increase to the capital accounts of our common units, i-units, and General Partner interest on a pro-rata basis. For further details, refer to Note 14 *Related Party Transactions*.

On January 26, 2017, we exercised our option under the Eastern Access Project joint funding arrangement to acquire an additional 15% interest in the Eastern Access Project, at its book value of approximately $360 million, which is now in service. This transaction reduced noncontrolling interest by approximately $360 million. As of June 30, 2017, we and our General Partner owned 40% and 60% of the partnership interest in Series EA of Enbridge Energy, Limited Partnership (OLP), which we refer to as the EA interest, respectively. For further details, refer to Note 14 *Related Party Transactions*.

11. PARTNERS' CAPITAL

Redemption of Series 1 Preferred Units

On April 27, 2017, we redeemed all of our outstanding Series 1 Preferred Units held by our General Partner at face value of $1.2 billion in cash. The remaining unamortized beneficial conversion feature discount of $8.5 million was recorded against the capital balance of the General Partner. Additionally, we repaid $357.3 million in deferred distributions on the Series 1 Preferred Units owed to our General Partner upon the closing of the Midcoast sale.

Issuance of Class A Units

On April 27, 2017, we funded the redemption of the Series 1 Preferred Units through the issuance of 64,308,682 Class A common units to our General Partner at a price of $18.66 per Class A common unit. The Class A common units were recognized on April 27, 2017, at fair value. The fair value of the Class A common units was $18.57 per unit, the market closing price on April 27, 2017, resulting in a $1.2 billion increase to the Class A unit capital account.

Simplification of Incentive Distributions

On April 27, 2017, a wholly-owned subsidiary of our General Partner irrevocably waived all of its rights associated with its 66.1 million Class D units and 1,000 IDUs, in exchange for the issuance of 1,000 Class F units. The waiving of the Class D and IDUs by a wholly-owned subsidiary of our General Partner represents an extinguishment, resulting in a de-recognition of the Class D and IDU's at their carrying value. The Class F units were recorded at their fair value of $263.0 million and the difference between the fair value of the Class F units and the de-recognized Class D and IDU's were recorded as an increase of $2.7 billion to our General Partner's capital account. We determined the fair value of the Class F units using an income approach on the basis of discounted cash flows from expected quarterly distributions. The Class F units are entitled to (i) 13% of all distributions of available cash in excess of $0.295 per unit, but less than or equal to $0.35 per unit, and (ii) 23% of all distributions of available cash in excess of $0.35 per unit.

Curing

Our limited partnership agreement does not permit capital deficits to accumulate in the capital accounts of any limited partner and thus requires that such capital account deficits be ''cured'' by additional allocations from the positive capital accounts of the common units, i-units, and our General Partner, generally on a pro-rata basis. For the six months ended June 30, 2017, the carrying amounts for the capital accounts of the Class A and Class B common units were reduced below zero due to distributions to limited partners in excess of earnings attributable to such limited partners. As a result, the capital balances of the i-units and our General Partner interests were reduced by $39.9 million and $11.9 million, respectively, to cure the applicable deficit balances.

12. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

As a result of the Midcoast sale, our net income and cash flows are no longer subject to volatility stemming from fluctuation in the prices of natural gas, NGLs, condensates and fractionation margins.

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 crude oil. 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 our Liquids segment. 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 are not designated 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.

Derivative Positions

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

	June 30, 2017	December 31, 2016
	(in millions)	
Other current assets	$ 1.2	$ —
Accounts payable and other	(159.0)	(145.4)
Other long-term liabilities	(23.8)	(21.3)
	$(181.6)	$(166.7)

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 interest rate contracts and crude oil sales contracts.

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

	June 30, 2017	December 31, 2016
	(in millions)	
Counterparty Credit Quality[(1)]		
AA	$ (82.6)	$ (79.2)
A	(63.6)	(58.4)
Lower than A	(35.4)	(29.1)
	$(181.6)	$(166.7)

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

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 have increased. 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

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

received or posted in the balances listed above. At June 30, 2017 and December 31, 2016, we did not have any cash collateral on our asset exposures. Cash collateral is classified as ‘‘Restricted cash’’ in our consolidated statements of financial position.

We provided letters of credit totaling $152.5 million and $119.5 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 2017 and December 31, 2016, 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 below the lowest level of investment grade at June 30, 2017, we would have been required to provide additional letters of credit in the amount of $30.9 million related to our positions.

At June 30, 2017 and December 31, 2016, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2017	December 31, 2016
	(in millions)	
United States financial institutions and investment banking entities	$(131.3)	$(121.7)
Non-United States financial institutions	(50.3)	(45.0)
	$(181.6)	$(166.7)

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.

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

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
	Financial Position Location	June 30, 2017	December 31, 2016	June 30, 2017	December 31, 2016
		(in millions)			
Derivatives designated as hedging instruments:[1]					
Interest rate contracts	Accounts payable and other	$ —	$—	$(159.0)	$(144.0)
Interest rate contracts	Other long-term liabilities	—	—	(23.8)	(21.1)
		—	—	(182.8)	(165.1)
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	1.2	—	—	—
Commodity contracts	Accounts payable and other	—	—	—	(1.4)
Commodity contracts	Other long-term liabilities	—	—	—	(0.2)
		1.2	—	—	(1.6)
Total derivative instruments		$1.2	$—	$(182.8)	$(166.7)

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

Accumulated Other Comprehensive Income

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. As of June 30, 2017 and December 31, 2016, we included in AOCI unrecognized losses of approximately $207.9 million and $223.3 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.

No commodity hedges were de-designated during the six months ended June 30, 2017 and 2016. We estimate that approximately $45.0 million, representing net losses from our cash flow hedging activities based on pricing and positions at June 30, 2017, will be reclassified from AOCI to earnings during the next 12 months.

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

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

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]
		(in millions)			
Three months ended June 30, 2017					
Interest rate contracts	$ (17.6)	Interest expense	$(10.4)	Interest expense	$(1.6)
Total	$ (17.6)		$(10.4)		$(1.6)
Three months ended June 30, 2016					
Interest rate contracts	$ (49.6)	Interest expense	$ (9.8)	Interest expense	$(1.5)
Total	$ (49.6)		$ (9.8)		$(1.5)
Six months ended June 30, 2017					
Interest rate contracts	$ (15.8)	Interest expense	$(20.7)	Interest expense	$(1.9)
Total	$ (15.8)		$(20.7)		$(1.9)
Six months ended June 30, 2016					
Interest rate contracts	$(135.2)	Interest expense	$(19.9)	Interest expense	$(3.4)
Commodity contracts	—	Commodity Costs	0.1	Commodity Costs	—
Total	$(135.2)		$(19.8)		$(3.4)

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges	
	2017	2016
	(in millions)	
Balance at January 1	$(339.3)	$(370.0)
Other comprehensive loss before reclassifications	(20.3)	(139.1)
Amounts reclassified from AOCI[1]	20.7	19.8
Net other comprehensive income (loss)	$ 0.4	$(119.3)
Balance at June 30	$(338.9)	$(489.3)

(1) 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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Losses on cash flow hedges:				
Interest Rate Contracts[1]	$10.4	$9.8	$20.7	$19.9
Total Reclassifications from AOCI	$10.4	$9.8	$20.7	$19.9

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

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

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
		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)	$1.4	$(3.9)	$3.1	$(3.1)
Total		$1.4	$(3.9)	$3.1	$(3.1)

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

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

(3) Includes settlement gains of $0.4 million and $1.2 million for the three months ended June 30, 2017 and 2016, respectively, and settlement gains of $0.4 million and $3.7 million for the six months ended June 30, 2017 and 2016, 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

	June 30, 2017				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$1.2	$—	$1.2	$—	$1.2

	December 31, 2016				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$—	$—	$—	$—	$—

Offsetting of Financial Liabilities and Derivative Liabilities

	June 30, 2017				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$(182.8)	$—	$(182.8)	$—	$(182.8)

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

	December 31, 2016				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$(166.7)	$—	$(166.7)	$—	$(166.7)

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 June 30, 2017 and December 31, 2016. 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. For the periods ending June 30, 2017 and December 31, 2016, we did not have any Level 3 derivative instruments.

	June 30, 2017			December 31, 2016		
	Level 1	Level 2	Total	Level 1	Level 2	Total
			(in millions)			
Interest rate contracts	$—	$(182.8)	$(182.8)	$—	$(165.1)	$(165.1)
Commodity contracts:						
Financial	—	1.2	1.2	—	(1.6)	(1.6)
Total	$—	$(181.6)	$(181.6)	$—	$(166.7)	$(166.7)

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: (i) quoted prices for assets and liabilities; (ii) time value; and (iii) 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.

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 at June 30, 2017 and December 31, 2016.

	June 30, 2017						December 31, 2016	
			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 2017								
Swaps								
Receive fixed/pay variable	Crude Oil	220,432	$52.14	$46.74	$1.2	$—	$—	$(1.6)

(1) Volumes of crude oil are measured in Bbl.

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

(3) The fair value is determined based on quoted market prices at June 30, 2017 and December 31, 2016, 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 nil at June 30, 2017 and December 31, 2016, 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 June 30, 2017	Fair Value[2] at December 31, 2016
			(dollars in millions)		
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 500	2.21%	$ —	$ (0.3)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (4.0)	$ (9.4)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (8.0)	$ (7.3)
Contracts settling prior to maturity					
2017 – Pre-issuance Hedges	Cash Flow Hedge	$1,000	4.07%	$(153.1)	$(136.2)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (18.3)	$ (13.1)

(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 June 30, 2017 and December 31, 2016, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustment gains of approximately $0.6 million and $1.2 million at June 30, 2017 and December 31, 2016, respectively.

13. SUPPLEMENTAL CASH FLOWS INFORMATION

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

	Six months ended June 30, 2017	Six months ended June 30, 2016
	(in millions)	
Total capital expenditures (excluding ‘‘Investments in joint ventures’’)	$207.3	$499.6
Decrease in construction payables	21.6	178.5
Cash used for additions to property, plant and equipment	$228.9	$678.1

14. 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.

14. RELATED PARTY TRANSACTIONS – (continued)

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.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $4.8 million as of June 30, 2017 and $28.4 million as of December 31, 2016, respectively, that we recorded as additions to ''Property, plant and equipment, net'' on our consolidated statements of financial position.

Affiliate Revenues

We record operating revenues in our Liquids segment for storage, transportation and terminalling services we provide to affiliates, which are presented in ''Transportation and other services — affiliate'' on our consolidated statements of income.

Sale of Accounts Receivable

We and certain of our subsidiaries were parties to a receivables purchase agreement (the Receivables Agreement), with an indirect, wholly-owned subsidiary of Enbridge. On April 27, 2017, we terminated our Receivables Agreement with the indirect, wholly-owned subsidiary of Enbridge in exchange for a one-time $5.0 million payment to us, which was recorded within ''Other income'' in our consolidated statements of income.

As a result of the termination of the Receivables Agreement we discontinued the sale of our receivables balance. For the three months ended June 30, 2017, no receivables were sold and derecognized. We sold and derecognized receivables of $428.1 million for the three months ended June 30, 2016. For the six months ended June 30, 2017 and 2016, we sold and derecognized receivables of $458.0 million and $894.4 million, respectively, to an indirect, wholly-owned subsidiary of Enbridge. We received no cash proceeds for the three months ended June 30, 2017 and received $468.9 million for the six months ended June 30, 2017. We received cash proceeds of $427.9 million and $894.0 million for the three and six months ended June 30, 2016, respectively.

Consideration for the receivables sold was 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 was recognized in ''Operating and administrative — affiliate'' expense in our consolidated statements of income. For the three and six months ended June 30, 2017 and 2016, the expense stemming from the discount on the receivables sold was not material.

As of June 30, 2017, we had no significant remaining derecognized receivables that had not been collected on behalf of the Enbridge subsidiary. As of December 31, 2016, we had $155.5 million of receivables, which had been sold and derecognized that had not been collected on behalf of the Enbridge subsidiary.

Financial Transactions with Affiliates

EUS Credit Agreement

In connection with our investment in the Bakken Pipeline System, on February 15, 2017, we entered into the EUS Credit Agreement. The EUS Credit Agreement was a committed senior unsecured revolving credit facility that permitted aggregate borrowings of up to, at any one time outstanding for the purpose of funding our investment in the Bakken Pipeline System, $1.5 billion, (i) on a revolving basis for a 364-day period and (ii) for a 364-day term on a non-revolving basis following the expiration of the revolving period; provided that the EUS Credit Agreement would mature on the date any project financing was completed. Loans under the EUS Credit Agreement accrued interest based, at our election, on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. A facility fee accrued at the applicable margin rate, which is based on our non-credit-enhanced, senior unsecured long-term debt rating at the applicable time.

On April 27, 2017, we re-paid the facility in full and terminated the EUS Credit Agreement. For further details refer to Note 9 *Debt.*

EUS 364-day Credit Facility

We are party to an unsecured revolving 364-day credit agreement (the EUS 364-day Credit Facility), with EUS. The EUS 364-day Credit Facility is a committed senior unsecured revolving credit facility that permits

14. RELATED PARTY TRANSACTIONS – (continued)

aggregate borrowings of up to, at any one time outstanding, $750 million, (i) on a revolving basis for a 364-day period and (ii) 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, at our election, based on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. On July 25, 2017 we entered into an agreement with EUS whereby the termination date was extended to July 24, 2018. The terms of our agreement with EUS remain unchanged. At that time, we may elect to convert any outstanding loans to term loans, which would mature on July 23, 2019. As of June 30, 2017, we had $420.6 million outstanding under this facility, excluding any accrued interest to date.

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 debt or equity securities in a registered public offering.

Distribution from MEP

The following table presents distributions paid by MEP prior to its sale on June 28, 2017, representing the noncontrolling interest in MEP, and to us for our ownership of Class A common units. No distributions were made during the second quarter of 2017.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to Noncontrolling Interest	Total MEP Distribution
			(in millions)	
January 26, 2017	February 14, 2017	$8.9	$7.6	$16.5

Joint Funding Arrangement for Bakken Pipeline

On April 27, 2017, we finalized a joint funding arrangement with our General Partner with respect to our investment in the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25% of DakTex, with an option for us to increase our interest by 20% at a price equal to net book value, at any time during the five years subsequent to the in-service date of the Bakken Pipeline system.

We received distributions from DakTex in the amount of $1.14 billion. The funds received were used to repay our borrowing, under the EUS Credit Agreement.

Joint Funding Arrangement for Line 3 Replacement

On January 26, 2017, our Board of Directors approved a joint funding arrangement with our General Partner for the U.S. L3R Program. Under the terms of the arrangement, our General Partner will fund 99% and we will fund 1% of the capital cost of the U.S. L3R Program. We have an option to increase our interest in the U.S. L3R Program assets up to 40% in the U.S. portion at book value at any time up to four years after the project goes into service. Our General Partner paid $450.1 million for its 99% interest in the project, including our share of the construction costs to date and other incremental amounts. The carrying amount of our 99% interest in the project at the transaction date was $411.0 million and was recorded as an increase to noncontrolling interest. The $39.1 million difference between the cash received and the carrying amount was recorded as an increase to the capital accounts of our common units, i-units, and General Partner interest on a pro-rata basis.

Our General Partner made equity contributions totaling $100.0 million to the OLP for the six months ended June 30, 2017, to fund its equity portion of the construction costs associated with the U.S. L3R Program.

Joint Funding Arrangement for Eastern Access Projects

We have a joint funding arrangement with the General Partner that established an additional series of partnership interests in the OLP, which we refer to as the EA interests. The EA interests were created to finance the Eastern Access Project 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.

14. RELATED PARTY TRANSACTIONS – (continued)

On January 26, 2017, we exercised our option under the Eastern Access joint funding arrangement to acquire an additional 15% interest in the Eastern Access Project, therefore increasing our ownership interest from 25% to 40% and reducing the interest of our General Partner form 75% to 60%, respectively. The exercise of our option occurred at book value of approximately $360 million and reduced noncontrolling interest by approximately $360 million. The Eastern Access Project was placed into service June 2016.

Our General Partner made equity contributions totaling $5.6 million and $7.2 million to the OLP for the six months ended June 30, 2017 and 2016, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Project.

Distribution to Series EA Interests

The following table presents distributions paid by the OLP during the six months ended June 30, 2017, 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 partner interests and certain limited partner interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to Noncontrolling Interest	Total Series EA Distribution
			(in millions)	
April 27, 2017	May 15, 2017	$29.3	$ 62.0	$ 91.3
January 26, 2017	February 14, 2017	22.9	68.8	91.7
		$52.2	$130.8	$183.0

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 the Mainline Expansion 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. Our General Partner owns 75% of the ME interests, and the projects are jointly funded by our General Partner at 75% and us at 25% with an option for us to increase our ownership interest by an additional 15% at cost, under the Mainline Expansion joint funding arrangement.

Our General Partner has made equity contributions totaling $26.0 million and $42.8 million to the OLP for the six months ended June 30, 2017 and 2016, 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 six months ended June 30, 2017, 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 partner and certain limited partner interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to Noncontrolling Interest	Total Series ME Distribution
			(in millions)	
April 27, 2017	May 15, 2017	$12.7	$38.0	$ 50.7
January 26, 2017	February 14, 2017	14.2	42.7	56.9
		$26.9	$80.7	$107.6

15. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we are, at times, subject to environmental remediation at various contaminated sites. 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 June 30, 2017 and December 31, 2016, our consolidated statements of financial position included $23.6 million and $99.8 million, respectively, in ''Environmental liabilities,'' and $55.3 million and $50.8 million, respectively, in ''Other long-term liabilities,'' that we have accrued for costs 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 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 evaluate the need for additional remediation activities and are performing the necessary 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.

As of June 30, 2017, 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 June 30, 2017. Our estimates exclude: (i) amounts we have capitalized, (ii) any claims associated with the release that may later become evident, (iii) amounts recoverable under insurance, and (iv) fines and penalties from other governmental agencies except as described in the *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.

15. COMMITMENTS AND CONTINGENCIES – (continued)

The components underlying our cumulative estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release, the majority of which have been paid, include the following:

	(in millions)
Response personnel and equipment	$ 547.3
Environmental consultants	224.3
Professional, regulatory, fines and penalties and other	443.4
Total	$1,215.0

For the six months ended June 30, 2017 and 2016, we made payments of $70.4 million and $12.9 million, respectively, for costs associated with the Line 6B crude oil release. As of June 30, 2017 and December 31, 2016, we had a remaining estimated liability of $67.9 million and $138.8 million, respectively.

Line 6B Fines and Penalties

At June 30, 2017, our total estimated costs related to the Line 6B crude oil release include $68.5 million in fines and penalties, which includes fines and penalties from the Department of Justice as discussed below.

Consent Decree

On May 23, 2017, the United States District Court for the Western District of Michigan, Southern Division (the Court), approved a Consent Decree (the Consent Decree), which is our signed settlement agreement with the United States Environmental Protection Agency (EPA) and the United States Department of Justice regarding Lines 6A and 6B crude oil releases, both of which occurred in 2010. On June 15, 2017, Enbridge made a total payment of $67.8 million as required by the Consent Decree, which reflects a $61.0 million civil penalty for the Line 6B release, a $1.0 million civil penalty for the Line 6A release, and $5.8 million for past removal costs and interest.

In addition to the monetary fines and penalties, the Consent Decree calls for replacement of Line 3, which we initiated in 2014 and is currently under regulatory review in the State of Minnesota; refer to Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations — Line 3 Replacement Program* for further details. The Consent Decree contains a variety of injunctive measures, including, but not limited to, enhancements to our comprehensive in-line inspection (ILI)-based spill prevention program; enhanced measures to protect the Straits of Mackinac; improved leak detection requirements; installation of new valves to control product loss in the event of an incident; continued enhancement of control room operations; and improved spill response capabilities. Collectively, these measures build on continuous improvements we have implemented since 2010 to our leak detection program, control center operations, and emergency response program. We estimate the total cost of these measures to be approximately $110.0 million, most of which is already incorporated into existing long-term capital investment and operational expense planning and guidance. Compliance with the terms of the Consent Decree is not expected to materially impact our overall financial performance.

Insurance

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. 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 release from Line 6B, excluding costs for fines and penalties.

Enbridge, together with us and its other affiliates, are covered under comprehensive property and liability insurance programs under which we are insured through April 30, 2018, with a liability program aggregate limit of $940.0 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 and other Enbridge subsidiaries.

A majority of the costs incurred for the July 2010 Line 6B crude oil release, other than fines and penalties, are covered by the insurance policies that expired on April 30, 2011, which had an aggregate limit of $650.0 million for

15. COMMITMENTS AND CONTINGENCIES – (continued)

pollution liability for Enbridge and its affiliates. Including our remediation spending through June 30, 2017, costs related to Line 6B exceeded the limits of the coverage available under these insurance policies. Through June 30, 2017, 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.

In March 2013, we and Enbridge filed a lawsuit against the insurers of $145.0 million of coverage, as one particular insurer disputed our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers asserted that their payment was 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 includes only one insurer.

Of the remaining $103.0 million coverage limit, $85.0 million was 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. On May 2, 2017, the arbitration panel issued a decision that was not favorable to Enbridge. As a result, we are unlikely to receive any additional insurance recoveries in connection with the Line 6B crude oil release.

Legal and Regulatory Proceedings

We are subject to various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. Some of these proceedings are covered, in whole or in part, by insurance.

We are in the early stages of discovery in relation to a unitholder derivative action, with trial scheduled in the second quarter of 2018. Accordingly, an estimate of reasonably possible losses, if any, associated with causes of action cannot be made until all of the facts, circumstances and legal theories relating to such claims and the defenses are fully disclosed and analyzed. We have not established any reserves relating to this action. We believe the action is without merit and expect to vigorously defend against it. We believe an unfavorable outcome to be more than remote but less than probable.

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. One action or claim is pending against us and our affiliates in state court in connection with the Line 6B crude oil release. Based on the current status of this case, we do not expect the outcome of this action 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 6B crude oil release as described above in this footnote.

16. SUBSEQUENT EVENTS

Distribution to Partners

On July 28, 2017, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2017. The distribution will be paid to unitholders of record as of August 7, 2017 of our available cash of $160.2 million at June 30, 2017, or $0.35 per limited partner unit. Of this distribution, $129.6 million will be paid in cash, $30.0 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.6 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 July 28, 2017, the managing general partner 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 $49.8 million to the noncontrolling interest in the Series EA, while $33.2 million will be paid to us.

16. SUBSEQUENT EVENTS – (continued)

Distribution to Series ME Interests

On July 28, 2017, the managing general partner 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 $41.3 million to the noncontrolling interest in the Series ME, while $13.8 million will be paid to us.

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, 2016, as filed with the Securities and Exchange Commission (SEC) on February 17, 2017.

Strategic Review

Our ultimate parent, Enbridge, recently completed a merger with Spectra Energy Corp. Enbridge had indicated that as part of the integration of the two companies, its U.S. sponsored vehicles, including us, would be reviewed in context of the combined enterprise.

On April 28, 2017, we announced the conclusion of our strategic review. We and our General Partner have taken the following actions to strengthen our financial position and outlook:

- The reduction of our quarterly distribution from $0.583 per unit to $0.35 per unit or from $2.33 per unit to $1.40 per unit on an annualized basis;
- The sale of all of our interests in our Midcoast gas gathering and processing business which closed on June 28, 2017, to our General Partner for $2.26 billion, including cash consideration of $1.31 billion and $953 million of existing outstanding indebtedness at MEP. A portion of these proceeds were used for other restructuring actions including the repayment of deferred distributions on our Series 1 Preferred Units, as discussed below;
- The finalization of our joint funding arrangement for our investment in the Bakken Pipeline System in which our General Partner now owns a 75% interest, and we own a 25% interest with an option to acquire an additional 20% interest from our General Partner at net book value. Refer to *Recent Developments — Bakken Pipeline System* for further information;
- The redemption of our outstanding Series 1 Preferred Units held by the General Partner at face value of $1.2 billion which was funded with the proceeds from the issuance of Class A common units to our General Partner;
- Subsequent to the Midcoast sale on June 28, 2017, we repaid $357.3 million in deferred distribution balance owed to our General Partner with the proceeds from the Midcoast sale; and
- The restructuring of our capital structure and modification of our incentive distribution rights through the irrevocable waiver by a wholly-owned subsidiary of our General Partner of all of that subsidiary's 66.1 million Class D units and 1,000 IDUs in consideration for issuance of a new class of units, Class F units. These units are entitled to (i) 13% of all distributions of available cash in excess of $0.295 per unit, but less than or equal to $0.35 per unit, and (ii) 23% of all distributions of available cash in excess of $0.35 per unit.

Previously, on January 26, 2017, we announced three additional strengthening actions to alleviate short-term capital expenditure requirements and enhance our cash flows as follows:

- We entered into a joint funding arrangement with our General Partner for the U.S. L3R Program whereby our General Partner paid approximately $450 million for a 99% interest in the project, including our share of the construction costs to date and other incremental amounts. Refer to *Expansion Projects — Commercially Secured Projects — U.S. Line 3 Replacement Program.*
- We acquired an additional 15% interest in the Eastern Access Project, at its book value of approximately $360 million, which is now in service. We utilized the funds received from the joint funding arrangement for the U.S. L3R Program to exercise our option under the Eastern Access joint funding arrangement.
- MEP entered into the merger agreement with our General Partner, whereby, on April 27, 2017, our General Partner acquired, for cash, all the outstanding publicly held Class A common units of MEP.

RESULTS OF OPERATIONS — OVERVIEW

We provide services to our customers and returns for our unitholders through our liquids business, which consists of interstate pipeline transportation and storage of crude oil and liquid petroleum. On June 28, 2017 our General Partner acquired all of our ownership interests in our Midcoast gas gathering and processing business through the acquisition of all of our 48.4% interest in Midcoast Operating, L.P., all of our ownership interests in Midcoast Holdings, L.L.C., and all of our limited partnership interests in MEP. For further details regarding the Midcoast sale, refer to Item 1. *Financial Statements*, Note 6 *Dispositions and Discontinued Operations.*

Our liquids business is conducted through three systems: our Lakehead, Mid-Continent and North Dakota systems. These systems largely consist of 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.

The results of our Midcoast gas gathering and processing business, which was acquired by our General Partner on June 28, 2017, are included in ''Loss from discontinued operations'' in our consolidated statements of income

The following table reflects our operating income by business segment and corporate charges for the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30,		Six months ended June 30,	
	2017	**2016**	**2017**	**2016**
	(in millions)			
Operating income (loss)				
Liquids	$ 316.3	$324.5	$ 587.5	$ 625.9
Other	(4.8)	(2.0)	(7.4)	(7.1)
Total operating income	311.5	322.5	580.1	618.8
Interest expense, net	(102.8)	(93.3)	(201.7)	(197.8)
Allowance for equity used during construction	10.7	13.3	21.0	25.6
Other income	11.4	0.2	11.4	0.4
Income before income tax expense	230.8	242.7	410.8	447.0
Income tax benefit (expense)	1.6	(2.0)	0.5	(3.6)
Income from continuing operations	232.4	240.7	411.3	443.4
Loss from discontinued operations, net of tax	(35.4)	(63.0)	(56.8)	(93.3)
Net income	197.0	177.7	354.5	350.1
Less: Net income attributable to:				
Noncontrolling interest	90.6	70.3	158.9	139.1
Series 1 preferred unit distributions	6.5	22.5	29.0	45.0
Accretion of discount on Series 1 preferred units	7.3	1.2	8.5	2.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 92.6	$ 83.7	$ 158.1	$ 163.7

Our Liquids segment operating income decreased $8.2 million and $38.4 million for the three and six months ended June 30, 2017, as compared to the same period in 2016, primarily as a result of the sale of the Ozark Pipeline System on March 1, 2017 and expiring toll surcharges and lower rail volumes on the North Dakota system. Partially offsetting the decrease in operating revenue was a gain of $51.5 million due to the sale of unnecessary pipe from the Sandpiper project. Volumes on our Lakehead system increased in 2017, when compared to the same period in 2016, primarily due to non-recurrence of wildfires in northeastern Alberta in the second quarter of 2016.

Loss from discontinued operations decreased $27.6 million and $36.5 million for the three and six months ended June 30, 2017, as compared to the same period in 2016, primarily due to changes in unrealized fair value gains and losses related to the revaluation of financial derivatives and reduced operating and administrative costs, offset by reduced natural gas throughput, storage margins, and NGL production margin. The reduced throughput was attributable to the continued low commodity price environment and reduction in drilling activity by producers.

Interest expense increased $9.5 million and $3.9 million for the three and six months ended June 30, 2017, respectively, as compared to the same period in 2016, due to an increase in our average outstanding debt balance, including additional borrowings from our General Partner.

Other income increased $11.2 million and $11.0 million for the three and six months ended June 30, 2017, respectively, as compared to the same period in 2016, mainly due to the equity earnings from the Bakken Pipeline System, which entered service in the month of June 2017.

Derivative Transactions and Hedging Activities

Contractual arrangements expose us to market risks associated with changes in (i) commodity prices where we receive crude oil in return for the services we provide or (ii) 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. Derivative financial instruments that do not receive hedge accounting under the provisions of authoritative accounting guidance create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not receive hedge accounting in our consolidated statements of income as follows:

- Liquids segment commodity-based derivatives — "Transportation and other services"
- 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:

	Three months ended June 30,		Six months ended June 30,	
	2017	**2016**	**2017**	**2016**
	(in millions)			
Liquids segment:				
Non-qualified hedges	$ 1.0	$(5.1)	$ 2.7	$ (6.8)
Other:				
Interest rate hedge ineffectiveness	(1.6)	(1.5)	(1.9)	(3.4)
Derivative fair value net gains (losses)	$(0.6)	$(6.6)	$ 0.8	$(10.2)

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:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Operating Results:				
Operating revenue	$596.5	$621.3	$1,201.2	$1,251.0
Operating expenses:				
Environmental costs, net of recoveries	3.5	0.1	13.8	17.0
Operating and administrative	153.5	132.1	304.0	269.3
Power	66.4	59.7	140.9	132.5
Depreciation and amortization	108.3	104.9	217.1	206.3
Gain on sale of assets	(51.5)	—	(62.1)	—
Total operating expenses	280.2	296.8	613.7	625.1
Operating income	$316.3	$324.5	$ 587.5	$ 625.9
Operating Statistics				
Lakehead system:				
United States(1)	1,986	1,887	2,021	1,980
Canada(1)	618	553	654	608
Total Lakehead system delivery volumes(1)	2,604	2,440	2,675	2,588
Barrel miles (billions)	183	168	375	359
Average haul (miles)	774	759	773	761
Mid-Continent system delivery volumes(1)	145	216	145	192
North Dakota system delivery volumes(1)	334	381	345	392
Total Liquids segment delivery volumes(1)	3,083	3,037	3,165	3,172

(1) Average Bpd in thousands.

Three months ended June 30, 2017, compared with the three months ended June 30, 2016

Operating income of our Liquids segment for the three months ended June 30, 2017, decreased $8.2 million, as compared to the same period in 2016, due to the reasons discussed below.

Operating revenue of our Liquids segment decreased $24.8 million for the three months ended June 30, 2017, as compared to the same period in 2016. The overall decrease in operating revenue is primarily attributable to the following:

- Operating revenue on the Mid-Continent system decreased $17.7 million for the three months ended June 30, 2017, as compared to the same period in 2016. The decrease in operating revenue was due primarily to the absence of revenue from the Ozark Pipeline System in second quarter 2017, as it was sold on March 1, 2017.
- Operating revenue on the North Dakota system decreased $9.1 million for the three months ended June 30, 2017, as compared to the same period in 2016, primarily due to the expiration of the Phase 5 looping and Phase 6 expansion surcharges, as well as lower rail revenue. Operating revenue decreased $7.3 million period over period due to the expiration of the Phase 5 and Phase 6 toll surcharges at December 31, 2016 and $1.5 million due to lower rail volumes to our Berthold rail facility as contracts on the facility expired.

- Operating revenue on our Lakehead system increased $2.1 million for the three months ended June 30, 2017, as compared to the same period in 2016. The increase in operating revenue was due to higher volumes on the system primarily as a result of non-recurrence of the wildfires in northeastern Alberta in the second quarter of 2016. The wildfires unfavorably impacted operating revenue by $20.0 million in the second quarter of 2016. Offsetting the favorable impact in the current period were lower average toll rates compared to the prior period.
- Environmental costs, net of recoveries, increased $3.4 million for the three months ended June 30, 2017, as compared to the same period in 2016, due to additional expenses incurred relating to the release on the Ozark Pipeline System on January 14, 2017.
- Operating and administrative expenses increased $21.4 million for the three months ended June 30, 2017, when compared to the same period in 2016. The increase was primarily due to Line 5 hydrostatic testing costs of $9.8 million, higher expenses of $7.6 million due to lower capital expenditures in the current period as these costs were capitalized in the comparative period, higher property taxes of $4.0 million and wind-down costs of $2.4 million associated with the Sandpiper project.
- During the second quarter we sold unnecessary pipe related to the Sandpiper project, resulting in a gain on disposal of $51.5 million offsetting the overall decrease in operating income.
- The increase in depreciation expense of $3.4 million for the three months ended June 30, 2017, when compared to the same period in 2016, is directly attributable to additional assets placed into service in 2016.

Six months ended June 30, 2017, compared with the six months ended June 30, 2016

Operating income of our Liquids segment for the six months ended June 30, 2017, decreased $38.4 million, as compared to the same period in 2016, due to the reasons discussed below.

Operating revenue of our Liquids segment decreased $49.8 million for the six months ended June 30, 2017, as compared to the same period in 2016. The overall decrease in operating revenue is primarily attributable to the following:

- Average daily delivery volumes on our Lakehead system increased; however, operating revenue for the six months ended June 30, 2017, decreased $2.6 million, as compared to the same period in 2016. The decrease in operating revenue was due to lower average toll rates, as a result of lower index rates adopted during the third quarter of 2016. Further contributing to the decrease in operating revenue period over period were $9.7 million of surcharges recognized in 2016 related to the recovery of hydrostatic testing costs on Line 2B, for which recovery was completed in 2016. No such surcharges were recognized in the same period of 2017. The decrease in operating revenue was partially offset by an increase in volume in 2017 from 2016 primarily due to non-recurrence of wildfires in northeastern Alberta in the second quarter of 2016, which unfavorably impacted second quarter 2016 revenues by $20.0 million.
- Operating revenue on the North Dakota system decreased $22.3 million for the six months ended June 30, 2017, as compared to the same period in 2016, primarily due to the expiration of the Phase 5 and Phase 6 expansion surcharges, as well as lower rail revenue. Operating revenue decreased $16.3 million period over period due to the expiration of the Phase 5 and Phase 6 toll surcharges at December 31, 2016 and $6.2 million due to lower rail volumes to our Berthold rail facility as contracts on the facility expired.
- Operating revenue on the Mid-Continent system decreased $24.9 million for the six months ended June 30, 2017, as compared to the same period in 2016. The decrease in operating revenue was due primarily to the absence of four months of revenue from the Ozark Pipeline System, which was sold on March 1, 2017, as well as a $3.7 million decrease due to lower storage and terminalling revenue for the Cushing system, primarily due to reduced volume based activity at the facility. Operational cost savings related to the sale of the Ozark Pipeline System amounted to $14.3 million for the first six months of 2017.
- Environmental costs, net of recoveries, decreased $3.2 million for the six months ended June 30, 2017, when compared with the same period in 2016. This decrease is due to a $15.0 million cost accrual for estimated fines and penalties associated with the Line 6B crude oil release in the first quarter of 2016. During the six months ended June 30, 2017, there were no cost accruals for the Line 6B crude oil release. The decrease was partially offset by a $12.6 million increase in environmental remediation costs related to a release on the Ozark Pipeline System on January 14, 2017.

- Operating and administrative expenses increased $34.7 million for the six months ended June 30, 2017, when compared to the same period in 2016, higher expenses of $10.9 million due to lower capital expenditures in the current period as these costs were capitalized in the comparative period, Line 5 hydrostatic testing costs of $10.3 million, Sandpiper expenses incurred of $6.6 million, and higher property taxes of $7.5 million.
- Offsetting the decrease in operating income was the gain of $51.5 million due to the sale of unnecessary pipe from the Sandpiper project, and the gain on disposal of the Ozark Pipeline System of $10.6 million in the first quarter of 2017.
- The increase in depreciation expense of $10.8 million for the six months ended June 30, 2017, when compared to the same period in 2016, is directly attributable to additional assets placed into service in 2016.

Recent Developments

Bakken Pipeline System

On February 15, 2017, through our joint venture with MPC, we completed the acquisition of an effective 27.6% interest in the Bakken Pipeline System for a purchase price of $1.5 billion.

We initially funded the $1.5 billion acquisition through a credit agreement provided by EUS, which is an affiliate of our General Partner. On April 27, 2017, we finalized the joint funding arrangement with our General Partner for our effective interest in the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25% of DakTex, which in turn owns the joint venture with MPC. We also have a five-year option to acquire an additional 20% interest in DakTex at net book value. With the finalization of this joint funding arrangement, we repaid the $1.5 billion outstanding under the EUS Credit Agreement and terminated the credit agreement.

The Bakken Pipeline System, which consists of DAPL and ETCOP, was placed into service June 1, 2017. It transports crude oil from the Bakken formation in North Dakota to markets in eastern PADD II, and the U.S. Gulf Coast. DAPL consists of 1,172 miles of 30-inch pipeline from the Bakken/Three Forks production area in North Dakota to Patoka, Illinois. It is expected to initially deliver in excess of 470,000 Bpd of crude oil and has the potential to be expanded to 570,000 Bpd. ETCOP consists of 62 miles of new 30-inch diameter pipe, 686 miles of converted 30-inch diameter pipe, and 40 miles of converted 24-inch diameter pipe from Patoka, Illinois to Nederland, Texas.

On February 9, 2017 the Standing Rock Sioux nation filed a lawsuit with the US District Court of Appeals (the Court of Appeals) contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit DAPL. The Standing Rock Sioux nation is requesting the Court of Appeals to order the operator to shut down the pipeline until the appropriate regulatory process is completed.

On June 14, 2017, the Court of Appeals ruled that the Army Corps failed to adequately consider the impact of an oil spill on the hunting and fishing rights of the Standing Rock Sioux nation and ordered the Army Corps to reconsider those components of its environmental analysis. The Court of Appeals did not rule on whether or not DAPL should cease operations, but on June 21, 2017 the Court of Appeals established a briefing schedule pursuant to which the parties to the litigation will be provided with an opportunity to submit written arguments on this issue. Final briefs must be filed by the parties in late August 2017, but it is not known when the Court of Appeals will issue its ruling. However, DAPL continues to operate pending the Court of Appeals' decision on this issue.

Renewal of Line 5 Easement

On January 4, 2017, the Tribal Council of the Bad River Band of Lake Superior Tribe of Chippewa Indians (the Band) issued a press release indicating that the Band had passed a resolution not to renew its interest in certain Line 5 easements through the Bad River Reservation. Line 5 is included within the Lakehead system. The Band's resolution calls for decommissioning and removal of the pipeline from all Bad River tribal lands and watershed and could impact Enbridge's ability to operate the pipeline on the Reservation. Since the Band passed the resolution, the parties have agreed to ongoing discussions with the objective of understanding and resolving the Band's concerns on a long-term basis.

Expansion Projects — Commercially Secured Projects

The following table summarizes the status of our commercially secured projects for the Liquids segment. Expenditures to date reflect total cumulative expenditures incurred from inception of the project to June 30, 2017.

	Estimated Capital Costs[(1)]	Expenditures to Date[(2)]	Expected In-Service Date	Status
Lakehead System Mainline Expansion:				
Line 61[(3),(4)]	$0.4 billion	$0.4 billion	2019	Substantially complete
U.S. Line 3 Replacement Program[(5),(6)]	$2.9 billion	$0.5 billion	2019	Pre-construction

(1) These amounts are estimates and are subject to upward or downward adjustment based on various factors.

(2) Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to June 30, 2017.

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

(4) Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program and the impact of cost to be reviewed. In 2015, we completed the expansion of pipeline capacity to 950,000 Bpd.

(5) As discussed under *U.S. Line 3 Replacement Program* below, the expected cost and in-service date of this project are under review by us in light of the schedule for regulatory review and approval communicated by the Minnesota Public Utilities Commission (MNPUC), on October 28, 2016.

(6) As discussed under *U.S. Line 3 Replacement Program* below, the Conflicts Committee and Board of Directors approved a joint funding arrangement with the General Partner for the U.S. L3R Program. The General Partner will fund 99% and we will fund 1% of the capital cost of the U.S. L3R Program.

Lakehead System Mainline Expansion

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 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 remaining projects in the Light Oil Market Access Program will further expand capacity on our U.S. mainline system and provide additional access to U.S. Midwestern refineries.

The Lakehead System Mainline Expansion Project includes several projects to expand capacity of our Lakehead system mainline between Neche, North Dakota, and Flanagan, Illinois. These projects include the expansion of our existing 36-inch diameter Alberta Clipper pipeline (Line 67) and our existing 42-inch diameter Southern Access pipeline (Line 61) and construction of the Spearhead North Twin pipeline (Line 78). The expansion of Line 67 and construction of Line 78 were completed during 2015.

The Line 67 pipeline capacity expansion remains subject to the receipt of an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at the United States/Canada border at its currently planned operating capacity of 800,000 Bpd. On February 10, 2017, the United States Department of State (DOS), the agency that is responsible for issuing permits for cross-border pipelines pursuant to a delegation of authority by the President under an Executive Order, issued a draft Supplemental Environmental Impact Statement (SEIS), which determined that there were no significant adverse environmental impacts from the planned capacity increase. The public comment period on the draft SEIS closed on March 27, 2017. The DOS is reviewing all received comments and preparing a final SEIS. As required by the Executive Order, the DOS initiated a 90-day inter-agency consultation period to solicit comments from certain other federal agencies on whether the Line 67 expansion will serve the national interest. The inter-agency consultation period commenced on March 28, 2017. Following issuance of the final SEIS and completion of the inter-agency consultation process, the Administration will make a decision and issue a Presidential Permit if it finds that doing so is in the national interest. The Administration's decision is expected later in the year.

In 2015, we completed the Line 61 expansion, between Superior, Wisconsin and Flanagan, Illinois, which increased the pipeline capacity to 950,000 Bpd. The expansion phase to increase the pipeline capacity to 1,200,000 Bpd at a total cost of approximately $0.4 billion was substantially completed in June of 2017. In conjunction with shippers, a decision was made to delay the in-service date of this remaining expansion phase to 2019 to align more closely with the anticipated in-service date for the U.S. L3R Program.

We operate the Lakehead System Mainline Expansions Projects on a cost-of-service basis. These Projects are jointly funded 75% by our General Partner and 25% by us under the Mainline Expansion Joint Funding Arrangement. We have the option to increase our economic interest held up to 15% at cost.

U.S. Line 3 Replacement Program

In 2014, we and Enbridge jointly 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. The U.S. portion of the Line 3 replacement program includes replacing 358 miles from the U.S./Canadian border at Neche, North Dakota to Superior, Wisconsin. The U.S. L3R Program will support the safety and operational reliability of the system, enhance flexibility, allow us and Enbridge to optimize throughput on the mainline system, and will restore approximately 370,000 Bpd capacity from Western Canada into Superior, Wisconsin.

We are in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate of Need (Certificate) and an approval of the pipeline's route (Route Permit) from the MNPUC. The MNPUC found both the Certificate and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. On February 1, 2016, the MNPUC issued a written order requiring the Minnesota Department of Commerce (DOC) to prepare an Environmental Impact Statement (EIS) before the Certificate and Route Permit processes commence. The DOC's draft EIS was issued May 15, 2017 and public comments regarding the draft EIS were accepted by the DOC until July 10, 2017. The DOC has stated that it anticipates issuing the Final EIS during August 2017. Construction of the Wisconsin portion of the Line 3 Replacement program commenced in late June 2017.

Based on the updated execution plan, the revised cost of the project is $2.9 billion. This modest increase is roughly 12% above prior estimates and reflects the ongoing delays in the regulatory process, as well as some additional scope, route modifications and other changes as a result of the extensive consultation efforts and obligation to meet permit conditions. We will recover our costs plus a return on capital based on our existing Facilities Surcharge Mechanism (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.

On January 26, 2017, we entered into a joint funding arrangement with our General Partner for the U.S. L3R Program. Under the terms of the arrangement, our General Partner and we will fund 99% and 1% of the capital cost of the U.S. L3R Program, respectively. We have an option to increase our interest in the U.S. L3R Program's assets to a total interest of up to 40% at book value at any time up to four years after the project goes into service. Our General Partner paid us approximately $450 million for its 99% interest in the project, including our share of the construction costs to date and other incremental amounts.

Natural Gas

The following table presents the operating results from discontinued operations of our Midcoast gas gathering and processing business, which have been segregated from our continuing operations in our consolidated statements of income:

	For the three months ended June 30,		For the six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Net loss from discontinued operations	$ (35.4)	$ (63.0)	$ (56.8)	$ (93.3)
Operating Statistics (MMBtu/d)				
East Texas	908,000	931,000	877,000	939,000
Anadarko	516,000	637,000	514,000	645,000
North Texas	172,000	203,000	174,000	210,000
Total	1,596,000	1,771,000	1,565,000	1,794,000
NGL Production (Bpd)	63,887	71,747	63,389	72,666

Three months ended June 30, 2017, compared with the three months ended June 30, 2016

Net losses from discontinued operations decreased $27.6 million for the three months ended June 30, 2017, compared to the same period in 2016. This decrease was mainly attributable to the following factors:

- Decrease of $54.2 million in operating revenue quarter over quarter due to a decrease in processing and storage margins, reduced natural gas throughput, and reduced NGL production volumes. These decreases were attributable to the continued low commodity price environment and reductions in drilling activity by producers in the areas we operate.

- Increase of $55.8 million which offset the decrease in operating revenue quarter over quarter due to changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices on the value of inventory.
- Net losses from discontinued operations included loss attributable to an asset impairment charge of $10.6 million incurred on certain trucking assets in 2016. No similar charge was recorded during the same period in 2017.
- Decrease in operating and administrative costs of $13.3 million quarter over quarter due to cost savings in the 2017 period as a result of workforce reductions, lower property taxes, and other cost reduction efforts.

Six months ended June 30, 2017, compared with the six months ended June 30, 2016

Net losses from discontinued operations decreased $36.5 million for the six months ended June 30, 2017, compared to the same period in 2016. The decrease was mainly attributable to the following factors:

- Decrease of $83.5 million in operating revenue period over period due to a decrease in processing and storage margins, reduced natural gas throughput, and reduced NGL production volumes. These decreases were attributable to the continued low commodity price environment and reductions in drilling activity by producers in the areas we operate.
- Increase of $88.8 million which offset the decrease in operating revenue period over period due to changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices on the value of inventory.
- Net losses from discontinued operations included loss attributable to an asset impairment charge of $10.6 million incurred on certain trucking assets in 2016. No similar charge was recorded during the same period in 2017.
- Decrease in operating and administrative costs of $20.7 million period over period due to cost savings in the 2017 period as a result of workforce reductions, lower property taxes, and other cost reduction efforts.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary operating cash requirements consist of normal operating expenses, maintenance capital expenditures, funding requirements associated with environmental costs, 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 under 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 includes developing and expanding our existing business through organic growth and targeted acquisitions, in addition to the strategies and actions taken as discussed above under *Strategic Review*.

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 the past, when we had attractive growth opportunities in excess of our own capital raising capabilities, our General Partner 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 our General Partner, but there can be no assurance that this funding can be obtained.

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $2.0 billion multi-year 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. We access our 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 June 30, 2017, we had approximately $1,090.0 million in available credit under the terms of our Credit Facilities.

We are also party to an unsecured revolving 364-day credit agreement with EUS. 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, $750.0 million. For the six months ended June 30, 2017, we had net repayments of approximately $329.4 million under the terms of the EUS 364-day Credit Facility.

In addition to the EUS 364-day Credit Facility, we entered into an additional credit facility with EUS, the EUS Credit Agreement, for the sole purpose of providing interim financing for our investment in the Bakken Pipeline System. On April 27, 2017, we finalized the joint funding arrangement with our General Partner with respect to our investment in the Bakken Pipeline System. As a result of this joint funding arrangement, we repaid the outstanding balance of $1.5 billion under the EUS Credit Agreement. For further details on the joint funding arrangement, refer to *Joint Funding Arrangements.*

For further details regarding our commercial paper program, our Credit Facilities, the EUS 364-day Credit Facility, refer to Item 1. *Financial Statements*, Note 9. *Debt*.

As of June 30, 2017, although we had a working capital deficit of approximately $0.6 billion, we had approximately $1.5 billion of consolidated liquidity to meet our ongoing operational, investing and financing needs as described above, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil release on Line 6B.

The following table sets forth the consolidated liquidity available to us at June 30, 2017.

	EEP
	(in millions)
Cash and cash equivalents	$ 123.7
Total commitments under the Credit Facilities	2,625.0
Total commitments under the EUS 364-day Credit Facility	750.0
Less: Amounts outstanding under the Credit Facilities	400.0
Amounts outstanding under the EUS 364-day Credit Facility	420.6
Principal amount of commercial paper outstanding	1,068.7
Letters of credit outstanding	66.3
Total	$1,543.1

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. From time to time, if the capital markets are constrained, our ability and willingness to complete future debt and equity offerings may be limited, which in turn, could affect our ability to execute our growth strategy or complete our planned construction projects. 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.

Subject to the foregoing, from time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. We have a current shelf registration statement on Form S-3 that allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

Joint Funding Arrangements

In order to obtain capital, we have explored, and may continue to explore, numerous options, including joint funding arrangements.

Joint Funding Arrangement for Bakken Pipeline System

On April 27, 2017, we finalized the joint funding arrangement with our General Partner with respect to our investment in the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25% of DakTex, the subsidiary through which we acquired our interest in the Bakken Pipeline System, with a five year option for us to increase our interest by 20% at net book value. With the finalization of the joint funding arrangement, we repaid the outstanding balance of $1.5 billion under the EU Credit Arrangement.

We received distributions from DakTex in the amount of $1.14 billion. The funds received were used to repay our borrowing, under the EUS Credit Agreement.

Joint Funding Arrangement for Line 3 Replacement Program

On January 26, 2017, we entered into a joint funding arrangement with our General Partner with respect to the U.S. L3R Program. Under the terms of the arrangement, our General Partner will fund 99% and we will fund 1% of the capital cost of the U.S. L3R Program, with an option for us to increase our interest in the U.S. L3R Program assets to a total of up to 40% at book value at any time up to four years after the project goes into service. Our General Partner paid approximately $450 million for its 99% interest in the project, including our share of the construction costs to date.

Our General Partner made equity contributions totaling $100.0 million to the OLP for the six months ended June 30, 2017, to fund its equity portion of the construction costs associated with the U.S. L3R Program.

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 the Eastern Access Project 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. Until January 26, 2017, our General Partner owned 75% of the EA interests and the projects were jointly funded by our General Partner at 75% and us at 25%. On January 26, 2017, we exercised our option under the Eastern Access joint funding arrangement to acquire an additional 15% interest in the Eastern Access Project, which is now in service, at its book value of approximately $360 million.

Our General Partner made equity contributions totaling $5.6 million and $7.2 million to the OLP for the six months ended June 30, 2017 and 2016, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Project.

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 the Mainline Expansion 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. Our General Partner owns 75% of the ME interests and the projects are jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion joint funding arrangement, which is similar to the Eastern Access joint funding arrangement.

Our General Partner has made equity contributions totaling $26.0 million and $42.8 million to the OLP for the six months ended June 30, 2017 and 2016, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

All other operations are captured by the Lakehead and Alberta Clipper interests, which are owned 100% by us. For further details regarding our joint funding arrangements refer to Item 1. *Financial Statements*, Note 14. *Related Party Transactions*.

Cash Requirements

Capital Spending

We categorize our capital expenditures as either maintenance capital or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful lives. 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.

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.

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.

We incurred capital expenditures of approximately $207.3 million for the six months ended June 30, 2017, including $19.8 million of maintenance capital expenditures. Of those capital expenditures, $151.6 million were financed by contributions from our General Partner via joint funding arrangements. At June 30, 2017, we had approximately $413.2 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment in the future.

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under our Credit Facilities, joint funding arrangements 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.

As discussed above, on February 15, 2017, through our joint venture with MPC we acquired a minority stake in the Bakken Pipeline System. For further details regarding our funding arrangements refer to *Recent Developments — Bakken Pipeline System*.

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 $388 million for the year ending December 31, 2017. We expect to receive funding of approximately $442 million from our General Partner based on our joint funding arrangements for the U.S. L3R Program, Eastern Access Projects and Mainline Expansion Projects. Although we anticipate making these expenditures in 2017, 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.

	Amounts attributable to us	Amounts attributable to the General Partner interest	Total Forecasted Expenditures[1]
	(in millions)	(in millions)	(in millions)
Liquids Projects			
Eastern Access Projects	$ 8	$ 12	$ 20
U.S. Mainline Expansions	21	64	85
Line 3 Replacement	4	366	370
Liquids Integrity Program	105	—	105
Expansion Capital	190	—	190
Maintenance Capital Expenditures	60	—	60
Total	$388	$442	$830

(1) Amounts do not include forecasted Allowance for Funds Used During Construction (AFUDC).

Distributions

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management during the six months ended June 30, 2017.

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)			
April 27, 2017	May 8, 2017	May 15, 2017	$0.3500	$159.6	$29.4	$0.6	$129.6
January 26, 2017	February 7, 2017	February 14, 2017	$0.5830	$264.8	$47.7	$1.0	$216.1

(1) We issued 1,000 i-units to Enbridge Management, the sole owner of our i-units, during 2017 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.

Environmental

Lakehead Line 6B Crude Oil Release

During the six months ended June 30, 2017, our cash flows were affected by the approximate $70.4 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil release that occurred in 2010 on Line 6B of our Lakehead system.

In March 2013, we and Enbridge filed a lawsuit against the insurers of $145.0 million of coverage, as one particular insurer disputed our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers asserted that their payment was 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 includes 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. On May 2, 2017, the arbitration panel issued a decision that was not favorable to Enbridge. As a result, we are unlikely to receive any additional insurance recoveries in connection with the Line 6B crude oil release. For more information regarding cost estimates and fines and penalties, refer to Item 1. *Financial Statements*, Note 15. *Commitments and Contingencies*.

Derivative Activities

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 June 30, 2017 for each of the indicated calendar years:

	Notional[1]	2017	2018	2019	2020	2021 & Thereafter	Total
				(in millions)			
Swaps:							
Crude Oil	220,432	$1.2	$—	$—	$—	$—	$1.2
Totals		$1.2	$—	$—	$—	$—	$1.2

(1) Notional amounts for 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 June 30, 2017 for each of the indicated calendar years:

	Notional	2017	2018	2019	2020	2021	Total[1]
				(in millions)			
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	1,430	$ (2.9)	$ (7.3)	$(1.8)	$—	$—	$ (12.0)
Pre-issuance hedges	1,350	(153.1)	(18.3)	—	—	—	(171.4)
		$(156.0)	$(25.6)	$(1.8)	$—	$—	$(183.4)

(1) Fair values exclude credit valuation adjustment gains of approximately $0.6 million at June 30, 2017.

Cash Flow Analysis

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

	Six months ended June 30, 2017	Six months ended June 30, 2016	Variance 2017 vs. 2016
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 214.8	$ 443.7	$(228.9)
Investing activities	(150.5)	(629.1)	478.6
Financing activities	(41.9)	180.3	(222.2)
Net increase (decrease) in cash and cash equivalents	22.4	(5.1)	27.5
Cash and cash equivalents at beginning of year – continuing operations	101.3	130.1	(28.8)
Cash and cash equivalents at end of period – continuing operations	$ 123.7	$ 125.0	$ (1.3)

Operating Activities

Net cash provided by our operating activities decreased $228.9 million for the six months ended June 30, 2017, compared to the same period in 2016, primarily due to decreased cash from net income after non-cash adjustments, as well as greater cash outflows from net changes in operating assets and liabilities. Decreased cash from net income after non-cash adjustments totaled $107.3 million and was primarily due to decreased rates on our liquids systems, as described in *Results of Operations — by Segment.*

Cash outflows from net changes in operating assets and liabilities increased $121.6 million. Our operating assets and liabilities fluctuate in the normal course of business due to various factors, including timing of cash payments and receipts.

Investing Activities

Net cash used in our investing activities during the six months ended June 30, 2017, decreased by $478.6 million compared to the same period in 2016, primarily due to increased cash inflows of $1,310.0 million received from the sale of the Midcoast assets as well as cash inflows of $314.0 million from the sale of the Ozark Pipeline System during the first quarter 2017 and the sale of unnecessary pipe in relation to the Sandpiper Project during the second quarter of 2017. Further, contributing to cash inflows were lower spending on capital projects of $409.0 million compared to the same period in 2016 as the remaining expansion of the Eastern Access Project was placed into service in June 2016. The increase in cash inflows was partially offset by outflows of $1,556.7 million from the acquisition of the Bakken Pipeline System.

Financing Activities

Net cash provided by our financing activities decreased $222.2 million for the six months ended June 30, 2017 compared to the same period in 2016 primarily due to the following:

- Net repayments on short-term financing sources of $687.5 million;
- Net repayments of $329.4 million under the EUS 364-day Credit Facility;
- Cash outflow of $1,557.3 million used in the redemption of the Series 1 preferred units and payment of the deferred distribution on these units;
- Cash outflow of $360.3 million as a result of the acquisition of additional 15% interest in the Eastern Access Projects; and
- Increased cash distributions to noncontrolling interest of $219.0 million due to suspension of cash distributions to our General Partner on the Series EA and ME during the six months ended June 30, 2016. Distributions resumed during the six months ended June 30, 2017.

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

- Net proceeds of $1,224.5 million received from the issuance of Class A units; and
- Contributions from noncontrolling interests of $1,285.0 million as a result of the finalization of our joint funding arrangement with our General Partner with respect to our investment in the Bakken Pipeline System whereby our General Partner owns 75% of DakTex and contribution from our General Partner to fund their equity portion of construction cost in relation to various joint funding arrangements.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

Effective April 1, 2017, FERC tariff No. 43.22.0 adjusted transportation rates for capacity expansion projects tariff rate changes known as FSM. The FSM allows recovery of costs associated with particular shipper-approved projects through an incremental surcharge that is layered on top of the base index rates. The FSM surcharge reflects our projected costs for these shipper-approved projects for 2017 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 $0.15 per barrel, to approximately $2.43 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 $0.13 per barrel, to approximately $2.01 per barrel. These decreases were primarily the result of an adjustment for the difference between estimated and actual costs and throughput for 2016, a decrease in forecasted capital additions for 2017 and greater volume levels.

On May 31, 2017, we filed FERC tariff No. 43.23.0 with an effective date of July 1, 2017 for our Lakehead system. We increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.001985 issued by the FERC on May 12, 2017 in Docket No. RM93-11-000.

North Dakota System

Effective January 1, 2017, FERC tariff No. 3.22.0 decreased overall rates to reflect the expiration of the Phase 5 Expansion and Phase 6 Mainline surcharges. The surcharges were cost-of-service based surcharges that were adjusted each year to actual costs and volumes. This January 1, 2017 filing decreased the average transportation rates for all crude oil movements on the North Dakota system with a destination of Clearbrook, Minnesota by approximately $0.43, reducing the average rate to approximately $1.33 per barrel.

Effective April 1, 2017, FERC tariff No. 3.23.0 established an initial interconnection charge at Stanley, North Dakota to facilitate a new pipeline interconnection with a third party. The newly established interconnection rate of $0.11 per barrel will be charged to shippers utilizing the interconnection.

Effective June 1, 2017, FERC tariff No. 5.0.0, a joint tariff with Sacagawea Pipeline Company LLC went into effect to establish joint tariff rates for the transportation of crude petroleum for shippers from receipt points at Johnson's Corner and Keene, North Dakota to Clearbrook, Minnesota.

Effective July 1, 2017, FERC tariff No. 3.24.0 increased committed rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.001985 issued by the FERC on May 12, 2017 in Docket No. RM93-11-000. Additionally, as per the Transportation Services Agreement (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 2016 and the forecasted operating costs and throughput for 2017.

Bakken System

Effective July 1, 2017, FERC tariff No. 2.4.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.001985 issued by the FERC on May 12, 2017, in Docket No. RM93-11-000.

Also effective July 1, 2017, FERC tariff No. 3.6.0 adjusted the committed rates in accordance with the TSA that was approved by the FERC in the Order on Petition For Declaratory Order issued November 22, 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 2016 and the forecasted operating costs and throughput for 2017.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016, filed on February 17, 2017, 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. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our fixed and variable rate debt obligations are issued. 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, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating.

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 December 31, 2016.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[(1)]	Fair Value[(2)] June 30, 2017	Fair Value[(2)] December 31, 2016
			(dollars in millions)		
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 500	2.21%	$ —	$ (0.3)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (4.0)	$ (9.4)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (8.0)	$ (7.3)
Contracts settling prior to maturity					
2017 – Pre-issuance Hedges	Cash Flow Hedge	$1,000	4.07%	$(153.1)	$(136.2)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (18.3)	$ (13.1)

(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 June 30, 2017 and December 31, 2016, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustment gains of approximately $0.6 million and $1.2 million at June 30, 2017 and December 31, 2016, 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 at June 30, 2017 and December 31, 2016.

	June 30, 2017						December 31, 2016	
			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 2017								
Swaps								
Receive fixed/pay variable	Crude Oil	220,432	$52.14	$46.74	$1.2	$—	$—	$(1.6)

(1) Volumes of crude oil are measured in Bbl.

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

(3) The fair value is determined based on quoted market prices at June 30, 2017 and December 31, 2016, 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 nil at June 30, 2017 and December 31, 2016, as well as cash collateral received.

Our credit exposure for OTC derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

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

	June 30, 2017	December 31, 2016
	(in millions)	
Counterparty Credit Quality[(1)]		
AA	$ (82.6)	$ (79.2)
A	(63.6)	(58.4)
Lower than A	(35.4)	(29.1)
	$(181.6)	$(166.7)

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

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 (the Exchange Act), within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2017. 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 June 30, 2017.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, Note 15. *Commitments and Contingencies*, which is incorporated herein by reference.

Brinckerhoff v. Enbridge Energy Co., Inc. et al.

On July 20, 2015, plaintiff Peter Brinckerhoff, individually and as trustee of the Peter R. Brinckerhoff Trust, filed a Verified Class Action and Derivative Complaint in the Court of Chancery of the State of Delaware against our General Partner, Enbridge, Enbridge Management, Enbridge Pipelines (Alberta Clipper) L.L.C., the OLP, us, and the following individuals: Jeffrey A. Connelly, Rebecca B. Roberts, Dan A. Westbrook, J. Richard Bird, J. Herbert England, C. Gregory Harper, D. Guy Jarvis, Mark A. Maki, and John K. Whelen, (collectively, the Director Defendants). The Complaint asserts both class action claims on behalf of holders of our Class A Common Units, as well as derivative claims brought on behalf of us. The plaintiff's claims arise out of the January 2, 2015 repurchase by us of our General Partner's 66.67% interest in the Alberta Clipper Pipeline (the 2015 Transaction). First, the plaintiff alleges that the 2015 Transaction improperly amended without Public Unitholder consent the Sixth Amended and Restated Agreement of Limited Partnership (the LPA) so as to allocate to the Public Unitholders taxable income that should have been allocated to the General Partner (the Special Tax Allocation). Second, the plaintiff alleges that we paid an unfair price for our General Partner's 66.67% interest in the Alberta Clipper Pipeline such that the 2015 Transaction breached the LPA because it was not fair and reasonable to the Partnership. The Complaint asserts claims for breach of fiduciary duty, breach of the covenant of good faith and fair dealing, breach of residual fiduciary duties, tortious interference, aiding and abetting, and rescission and reformation.

On April 29, 2016, the court granted Enbridge's and the Director Defendants' motion to dismiss and dismissed the case in its entirety. On May 26, 2016 the Plaintiff appealed that dismissal to the Delaware Supreme Court. On March 20, 2017, the Delaware Supreme Court reversed in part and affirmed in part the ruling of the Court of Chancery. Specifically, the Delaware Supreme Court affirmed that the enactment of the Special Tax Allocation did not breach the LPA, but reversed on the question of whether the Plaintiff had adequately alleged that the price we paid in the 2015 Transaction, including the Special Tax Allocation component, was fair and reasonable to the Partnership. The parties are currently in the early stages of discovery, with trial scheduled in the second quarter of 2018.

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, 2016, filed with the SEC on February 17, 2017.

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: August 2, 2017

By: /s/ Mark A. Maki
Mark A. Maki
President
(Principal Executive Officer)

Date: August 2, 2017

By: /s/ Chris Johnston
Chris Johnston
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
3.1	Amendment No. 2 to the Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., dated April 27, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed on May 3, 2017).
3.2	Eighth Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., dated as of April 27, 2017 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K, filed on May 3, 2017).
10.4	Purchase and Sale Agreement, dated as of April 27, 2017, by and between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on May 3, 2017).
10.5	Contribution and Redemption Agreement, dated as of April 27, 2017, by and between Enbridge Energy Company, Inc. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on May 3, 2017).
10.6	Contribution Agreement, dated as of April 27, 2017, by and among Enbridge Energy Company, Inc., Enbridge Energy Partners, L.P. and Enbridge Holdings (DakTex) L.L.C. (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed on May 3, 2017).
10.7	Amended and Restated Limited Liability Company Agreement of Enbridge Holdings (DakTex) L.L.C., dated April 27, 2017, between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed on May 3, 2017).
10.8	Seventh Amended to Credit Agreement dated as of June 5, 2017, by and among Enbridge Energy Partners, L.P. and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 8, 2017)
10.9	First Amended to Credit Agreement dated as of June 5, 2017, by and among Enbridge Energy Partners, L.P. and Enbridge (U.S.) Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 8, 2017)
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

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

I, 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 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 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: August 2, 2017

By: /s/ Mark A. Maki

Mark A. Maki
President
(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, Chris Johnston, 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 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 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: August 2, 2017

By: /s/ Chris Johnston

Chris Johnston
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 June 30, 2017 (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: August 2, 2017

By: /s/ Mark A. Maki

Mark A. Maki
President
(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 June 30, 2017 (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: August 2, 2017

By: /s/ Chris Johnston

Chris Johnston
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C.
(as delegate of the General Partner)