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

FORM 10-Q

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

For the quarterly period ended March 31, 2013

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
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

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

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

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

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

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

The registrant had 254,208,428 Class A common units outstanding as of May 1, 2013.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our" 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."

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond the Partnership's ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for or the supply of, forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and NGLs, including the rate of development of the Alberta Oil Sands; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline systems; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to whom we sell products; (5) hazards and operating risks that may not be covered fully by insurance, including those related to Lines 6B; (6) changes in or challenges to our tariff rates; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.

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, 2012 and our subsequently filed Quarterly Reports on Form 10-Q, 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

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions, except per unit amounts)	
Operating revenue (Note 10)	$1,693.0	$1,819.5
Operating expenses		
Cost of natural gas (Notes 4 and 10)	1,191.4	1,296.9
Environmental costs, net of recoveries (Note 9)	178.5	3.2
Operating and administrative	194.9	196.9
Power (Note 10)	33.6	41.2
Depreciation and amortization (Note 5)	92.2	83.6
	1,690.6	1,621.8
Operating income	2.4	197.7
Interest expense (Notes 6 and 10)	76.4	83.6
Other income (Note 13)	8.1	—
Income (loss) before income tax expense	(65.9)	114.1
Income tax expense (Note 11)	1.8	2.1
Net income (loss)	(67.7)	112.0
Less: Net income attributable to noncontrolling interest (Note 8)	15.6	13.0
Net income (loss) attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ (83.3)	$ 99.0
Net income (loss) allocable to limited partner interests	$ (112.9)	$ 71.7
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	$ (0.36)	$ 0.25
Weighted average limited partner units outstanding	307.2	284.7

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions)	
Net income (loss)	$(67.7)	$112.0
Other comprehensive income, net of tax benefit $0.1 million as of March 31, 2012 (Note 10)	29.7	35.4
Comprehensive income (loss)	(38.0)	147.4
Less: Comprehensive income attributable to noncontrolling interest (Note 8)	15.6	13.0
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$(53.6)	$134.4

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the three month period ended March 31,	
	2013	**2012**
	(unaudited; in millions)	
Cash provided by operating activities		
Net income (loss)	$ (67.7)	$ 112.0
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	92.2	83.6
Derivative fair value net losses (Note 10)	4.2	6.9
Inventory market price adjustments (Note 4)	0.8	2.4
Environmental costs (recoveries) (Note 9)	173.5	(1.2)
Other (Note 14)	(4.2)	2.8
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(23.3)	71.1
Due from General Partner and affiliates	(5.4)	8.4
Accrued receivables	142.0	73.7
Inventory (Note 4)	(14.6)	14.5
Current and long-term other assets (Note 10)	(8.0)	5.9
Due to General Partner and affiliates	29.3	17.7
Accounts payable and other (Notes 3 and 10)	(67.6)	33.4
Environmental liabilities (Note 9)	(13.6)	(52.3)
Accrued purchases	(40.7)	(132.3)
Interest payable	6.9	8.8
Property and other taxes payable	2.1	2.1
Net cash provided by operating activities	205.9	257.5
Cash used in investing activities		
Additions to property, plant and equipment (Note 5)	(417.1)	(261.3)
Changes in construction payables	12.2	17.0
Asset acquisitions	(0.9)	—
Proceeds from the sale of net assets	5.0	—
Joint venture contributions	(36.8)	(27.6)
Other	(0.3)	(0.1)
Net cash used in investing activities	(437.9)	(272.0)
Cash provided by (used in) financing activities		
Net proceeds from unit issuances	278.7	—
Distributions to partners (Note 7)	(176.1)	(159.4)
Repayments to General Partner (Note 8)	(6.0)	(6.0)
Net commercial paper borrowings (Note 6)	140.0	50.1
Contribution from noncontrolling interest (Note 8)	22.8	—
Distributions to noncontrolling interest (Note 8)	(13.8)	(15.8)
Net cash provided by (used in) financing activities	245.6	(131.1)
Net increase (decrease) in cash and cash equivalents	13.6	(145.6)
Cash and cash equivalents at beginning of year	227.9	422.9
Cash and cash equivalents at end of period	$ 241.5	$ 277.3

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2013	December 31, 2012
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 241.5	$ 227.9
Receivables, trade and other, net of allowance for doubtful accounts of $1.9 million in 2013 and 2012 (Note 9)	165.7	142.4
Due from General Partner and affiliates	32.8	27.2
Accrued receivables	427.7	569.7
Inventory (Note 4)	86.5	72.7
Other current assets (Note 10)	42.3	48.0
	996.5	1,087.9
Property, plant and equipment, net (Note 5)	11,263.7	10,937.6
Goodwill	246.7	246.7
Intangibles, net	256.0	257.2
Other assets, net (Note 10)	317.0	267.4
	$13,079.9	$12,796.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 73.8	$ 43.5
Accounts payable and other (Notes 3, 10 and 13)	576.3	646.0
Environmental liabilities (Note 9)	251.2	108.0
Accrued purchases	443.4	484.1
Interest payable	75.9	69.0
Property and other taxes payable (Note 11)	73.5	71.4
Note payable to General Partner (Note 8)	12.0	12.0
Current maturities of long-term debt (Note 6)	200.0	200.0
	1,706.1	1,634.0
Long-term debt (Note 6)	5,641.9	5,501.7
Note payable to General Partner (Note 8)	312.0	318.0
Other long-term liabilities (Notes 9, 10 and 11)	98.4	95.2
	7,758.4	7,548.9
Commitments and contingencies (Note 9)		
Partners' capital (Notes 7 and 8)		
Class A common units (254,208,428 at March 31, 2013 and December 31, 2012)	3,363.0	3,590.2
Class B common units (7,825,500 at March 31, 2013 and December 31, 2012)	76.9	83.9
i-units (52,283,651 and 41,198,424 at March 31, 2013 and December 31, 2012, respectively)	1,052.9	801.8
General Partner	301.4	299.0
Accumulated other comprehensive income (loss) (Note 10)	(290.8)	(320.5)
Total Enbridge Energy Partners, L.P. partners' capital	4,503.4	4,454.4
Noncontrolling interest (Note 8)	818.1	793.5
Total partners' capital	5,321.5	5,247.9
	$13,079.9	$12,796.8

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

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of March 31, 2013, our results of operations for the three month periods ended March 31, 2013 and 2012 and our cash flows for the three month periods ended March 31, 2013 and 2012. We derived our consolidated statement of financial position as of December 31, 2012 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012. Our results of operations for the three month period ended March 31, 2013 should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for crude oil, seasonality of portions of our Natural Gas business, timing and completion of our construction projects, maintenance activities, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value and the effect of environmental costs and related insurance recoveries on our Lakehead system. Our interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

Comparative Amounts

We made a reclassification of $4.3 million for oil measurement gains from “Oil measurement adjustments” to “Operating and administrative” in our consolidated statement of income for the three month period ended March 31, 2012.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner, or Enbridge Energy Company, Inc., and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, including any incentive distribution rights, or IDRs, embedded in the general partner interest, to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We also allocate any earnings in excess of distributions to our General Partner and limited partners utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement as follows:

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

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

	For the three month period ended March 31, 2013	2012
	(in millions, except per unit amounts)	
Net income (loss)	$ (67.7)	$ 112.0
Less: Net income attributable to noncontrolling interest	15.6	13.0
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	(83.3)	99.0
Less distributions paid:		
Incentive distributions to our General Partner	(31.9)	(25.9)
Distributed earnings allocated to our General Partner	(3.5)	(3.0)
Total distributed earnings to our General Partner	(35.4)	(28.9)
Total distributed earnings to our limited partners	(170.8)	(151.8)
Total distributed earnings	(206.2)	(180.7)
Overdistributed earnings	$(289.5)	$ (81.7)
Weighted average limited partner units outstanding	307.2	284.7
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit [1]	$ 0.56	$ 0.53
Overdistributed earnings per limited partner unit [2]	(0.92)	(0.28)
Net income (loss) per limited partner unit (basic and diluted)	$ (0.36)	$ 0.25

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

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

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $17.5 million at March 31, 2013 and $22.8 million at December 31, 2012 are included in "Accounts payable and other" on our consolidated statements of financial position.

4. INVENTORY

Our inventory is comprised of the following:

	March 31, 2013	December 31, 2012
	(in millions)	
Materials and supplies	$ 1.9	$ 1.9
Crude oil inventory	15.4	12.7
Natural gas and NGL inventory	69.2	58.1
	$86.5	$72.7

The “Cost of natural gas” on our consolidated statements of income includes charges totaling $0.8 million and $2.4 million for the three month periods ended March 31, 2013 and 2012, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect the current market value.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2013	December 31, 2012
	(in millions)	
Land	$ 40.6	$ 40.4
Rights-of-way	615.2	604.5
Pipelines	6,979.6	6,662.3
Pumping equipment, buildings and tanks	1,840.4	1,646.4
Compressors, meters and other operating equipment	1,781.5	1,755.7
Vehicles, office furniture and equipment	243.7	222.7
Processing and treating plants	492.6	489.8
Construction in progress	1,709.8	1,867.2
Total property, plant and equipment	13,703.4	13,289.0
Accumulated depreciation	(2,439.7)	(2,351.4)
Property, plant and equipment, net	$11,263.7	$10,937.6

6. DEBT

Credit Facilities

In September 2011, we entered into a credit agreement with Bank of America as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility. The agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2.0 billion, a letter of credit subfacility and a swing line subfacility. Effective September 26, 2012, we extended the maturity date to September 26, 2017 and amended it to adjust the base interest rates.

Our Credit Facility previously was amended, and our 364-Day Credit Facility, which is discussed below, is written, to exclude up to $650 million of the costs associated with the remediation of the area affected by the Line 6B crude oil release from the EBITDA component of the consolidated leverage ratio covenant in each of those facilities, which we refer to as our Credit Facilities. As previously disclosed, we received an order on March 14, 2013 from the Environmental Protection Agency, or the EPA, requiring additional work related to the Line 6B crude oil release, which we estimate to be approximately $175.0 million. Since this additional amount is not excluded from the computation of EBITDA component of the consolidated leverage ratio covenant, and we recorded that amount as an expense in the first three months of 2013, we anticipated that we would not be in compliance with the consolidated leverage ratio covenant at March 31, 2013. On March 29, 2013, we obtained waivers from all lenders under each of our Credit Facilities waiving our compliance with the consolidated leverage ratio determined as of March 31, 2013. The actual ratio was above the maximum ratio allowed by the Credit Facilities. Our ability to comply with that covenant in the future will depend on our ability to issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. See Part II, Item 1A. *Risk Factors, “Ability to Comply with Financial Covenants of the Credit Facilities*.”

On July 6, 2012, we entered into a credit agreement with JPMorgan Chase Bank, as administrative agent, and a syndicate of 12 lenders, which we refer to as the 364-Day Credit Facility. The agreement is a committed senior unsecured revolving credit facility pursuant to which the lenders have committed to lend us up to $675.0 million: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion; and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods. On February 8, 2013, we amended the 364-Day Credit Facility to reflect an increase in the lending commitments to $1.1 billion. The amended credit agreement has terms consistent with the original 364-Day Credit Facility.

Our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at March 31, 2013, we could borrow $1.6 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$3,100.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,300.0
Letters of credit outstanding	189.1
Total amount we could borrow at March 31, 2013	$1,610.9

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the three month periods ended March 31, 2013 and 2012, we have not renewed any LIBOR rate borrowings or base rate borrowings on a non-cash basis.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper that is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At March 31, 2013, we had $1.3 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.40%, excluding the effect of our interest rate hedging activities. At December 31, 2012, we had $1.2 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.46%, excluding the effect of our interest rate hedging activities. Our policy is to limit the commercial paper we issue by the amounts available for us to borrow under our Credit Facilities.

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.

Fair Value of Debt Obligations

The table below presents the carrying amounts and approximate fair values of our debt obligations. The carrying amounts of our outstanding commercial paper and borrowings under our Credit Facilities and prior credit facilities approximate their fair values at March 31, 2013 and December 31, 2012, respectively, due to the short-term nature and frequent repricing of these obligations. The fair value of our outstanding commercial paper and borrowings under our Credit Facilities are included with our long-term debt obligations below since we have the ability to refinance the amounts on a long-term basis. The approximate fair values of our long-term debt obligations are determined 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.

	March 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$1,300.0	$1,300.0	$1,160.0	$1,160.0
4.750% Senior Notes due 2013	200.0	201.6	200.0	203.9
5.350% Senior Notes due 2014	200.0	215.6	200.0	215.6
5.875% Senior Notes due 2016	299.9	341.5	299.9	345.1
7.000% Senior Notes due 2018	99.9	123.1	99.9	124.6
6.500% Senior Notes due 2018	398.9	478.4	398.8	484.1
9.875% Senior Notes due 2019	500.0	700.1	500.0	710.5
5.200% Senior Notes due 2020	499.9	570.6	499.9	575.4
4.200% Senior Notes due 2021	599.0	638.0	598.9	644.2
7.125% Senior Notes due 2028	99.8	133.9	99.8	137.5
5.950% Senior Notes due 2033	199.8	236.5	199.8	244.2
6.300% Senior Notes due 2034	99.8	122.3	99.8	126.5
7.500% Senior Notes due 2038	399.0	553.5	399.0	573.8
5.500% Senior Notes due 2040	546.3	581.8	546.3	605.5
8.050% Junior subordinated notes due 2067	399.6	451.1	399.6	453.6
Total	$5,841.9	$6,648.0	$5,701.7	$6,604.5

7. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management, or Enbridge Management, during the three month period ended March 31, 2013.

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)			
January 30, 2013	February 7, 2013	February 14, 2013	$0.5435	$198.9	$22.4	$0.4	$176.1

(1) We issued 735,227 i-units to Enbridge Management, the sole owner of our i-units, during 2013 in lieu of cash distributions.

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

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary, Enbridge

Energy, Limited Partnership, or the OLP, for the three month periods ended March 31, 2013 and 2012. The noncontrolling interest in the OLP arises from the joint funding arrangements with our General Partner and its affiliate to finance: (1) construction of the United States portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Pipeline; (2) expansion of our Lakehead system to transport crude oil to destinations in the Midwest United States, which we refer to as the Eastern Access Projects; and (3) further expansion of our Lakehead system to transport crude oil between Neche, North Dakota and Superior, Wisconsin, which we refer to as the Mainline Expansion Projects.

	For the three month period ended March 31,	
	2013	2012
	(in millions)	
General and limited partner interests		
Beginning balance	$4,774.9	$4,483.1
Proceeds from issuance of partnership interests, net of costs	278.7	—
Net income (loss)	(83.3)	99.0
Distributions	(176.1)	(159.4)
Ending balance	$4,794.2	$4,422.7
Accumulated other comprehensive income (loss)		
Beginning balance	$ (320.5)	$ (316.5)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings	6.0	13.8
Unrealized net loss on derivative financial instruments	23.7	21.6
Ending balance	$ (290.8)	$ (281.1)
Noncontrolling interest		
Beginning balance	$ 793.5	$ 445.5
Capital contributions	22.8	—
Comprehensive income:		
Net income	15.6	13.0
Distributions to noncontrolling interest	(13.8)	(15.8)
Ending balance	$ 818.1	$ 442.7
Total partners' capital at end of period	$5,321.5	$4,584.3

Investments

In March 2013, Enbridge Management completed a public offering of 10,350,000 Listed Shares, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 per Listed Share. Enbridge Management received net proceeds of $272.9 million, which were subsequently invested in our i-units equal to the number of Listed Shares sold in the offering. We intend to use the proceeds from our issuance of i-units to Enbridge Management to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

The following table presents the net proceeds from the i-unit issuance for the three month period March 31, 2013.

2013 Issuance Date	Number of i-units Issued	Price per i-unit	Net Proceeds to the Partnership (1)	General Partner Contribution (2)	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amount)			
March	10,350,000	$26.37	$272.9	$5.8	$278.7

(1) Net of underwriters' fees, discounts, commissions, and estimated costs paid by Enbridge Management.

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

8. RELATED PARTY TRANSACTIONS

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge Inc., or Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline, with the unpaid balance due in 2020. The approved terms for the Alberta Clipper Pipeline are described in the “Alberta Clipper United States Term Sheet,” which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for the A1 Term Note for the three month periods ended March 31, 2013 and 2012 are as follows:

	A1 Term Note March 31,	
	2013	2012
	(in millions)	
Beginning Balance	$330.0	$342.0
Repayments	(6.0)	(6.0)
Ending Balance	$324.0	$336.0

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $12.9 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month period ended March 31, 2013. We also allocated $13.0 million for the same three month period ended March 31, 2012. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the three month period ended March 31, 2013, representing the noncontrolling interest in the Series AC and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
January 30, 2013	February 14, 2013	$6.9	$13.8	$20.7

Joint Funding Arrangement for Eastern Access Projects

In May 2012, we amended and restated the partnership agreement of the OLP to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. Our General Partner indirectly owns 60% of all assets, liabilities and operations related to the Eastern Access Projects. We and our affiliates own the remaining 40% of the Eastern Access Projects as per the Eastern Access Joint Funding Agreement. Before June 30, 2013, we will have the option to reduce our funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we will also have the option to increase our economic interest held at that time by up to 15 percentage points.

We allocated earnings from the Eastern Access Projects in the amount of $2.7 million to our General Partner for its 60% ownership of the EA interest for the period ended March 31, 2013. We have presented this amount we allocated to our General Partner in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

Joint Funding Arrangement for the U.S. Mainline Expansion

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. The projects will be jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. We also have an option, exercisable prior to June 30, 2013, for the Partnership to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points. All other operations are captured by the LH interests.

Our General Partner has made equity contributions totaling $22.8 million to the OLP for the three month period ended March 31, 2013 to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion. No such contributions were made during the three month period ended March 31, 2012.

9. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities through 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 March 31, 2013 and December 31, 2012, we had $35.1 million and $18.3 million, respectively, included in "Other long-term liabilities," that we have accrued for costs we have recognized primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Line 6B Crude Oil Release

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

As of March 31, 2013 and as previously disclosed in March 2013, our total cost estimate for the Line 6B crude oil release is $995.0 million, which is an increase of $175.0 million as compared to December 31, 2012. This total estimate is before insurance recoveries and excluding additional fines and penalties which may be imposed by federal, state and local governmental agencies, other than the Pipeline and Hazardous Materials Safety Administration, or PHMSA, civil penalty of $3.7 million, we paid during the third quarter of 2012. On March 14, 2013, we received an order from the EPA, which we refer to as the Order, that defined the scope which requires additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. We submitted our initial proposed work plan required by the EPA on April 4, 2013, and we resubmitted the workplan on April 23, 2013 and are awaiting a response from the EPA. We do not believe these refinements in the workplan will materially change our cost estimate. The Order states that the work must be completed by December 31, 2013.

The $175.0 million increase in the total cost estimate is attributable to additional work required by the Order. The actual costs incurred may differ from the foregoing estimate as we discuss our work plan with the EPA and work with other regulatory agencies to assure that our work plan complies with their requirements. Any such incremental costs will not be recovered under our insurance policies as our expected costs for the incident will exceed the limits of our insurance coverage.

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 March 31, 2013. Our estimates do not include amounts we have capitalized or any claims associated with the release that may later become evident and is before any insurance recoveries and excludes fines and penalties from other governmental agencies other than the PHMSA civil penalty described above. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

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

	(in millions)
Response Personnel & Equipment	$467
Environmental Consultants	171
Professional, regulatory and other	357
Total	$995

For the three month periods ended March 31, 2013 and 2012 we made payments of $7.8 million and $50.7 million, respectively, for costs associated with the Line 6B crude oil release. For the three month period ended March 31, 2013, we recognized a $2.7 million impairment for homes purchased due to the Line 6B crude oil release which is included in the "Environmental costs, net of recoveries" on our consolidated statements of income. As of March 31, 2013 and December 31, 2012, we had a remaining estimated liability of $280.3 million and $115.8 million, respectively.

Lines 6A & 6B Fines and Penalties

Our total estimated costs for the Line 6A crude oil release of $48.0 million, of which $1.0 million is the remaining liability at March 31, 2013, does not include an estimate for fines and penalties at March 31, 2013, which may be imposed by the EPA and PHMSA, in addition to other federal, state and local governmental agencies. At March 31, 2013, our estimated costs to the Line 6B crude oil release include $3.7 million in civil penalties assessed by PHMSA that we paid during the third quarter of 2012, but do not include any other fines or penalties which may be imposed by other governmental agencies. Several factors remain outstanding at the end of the period that we consider critical in estimating the amount of additional fines and penalties that we may be assessed.

Due to the absence of sufficient information, we cannot provide a reasonable estimate of our liability for potential additional fines and penalties that we could be assessed in connection with each of the releases. As a result, except for the PHMSA civil penalty, we have not recorded any liability for expected fines and penalties.

Insurance Recoveries

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

The claims for the crude oil release for Line 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability. Based on our remediation spending through March 31, 2013, we have exceeded the limits of coverage under this insurance policy. In the first quarter of 2012, we received payments of $50.0 million for insurance receivable claims we previously recognized as a reduction to environmental costs in 2011. For the three month period ended March 31, 2013, we did not receive any payments for insurance receivable claims. As of March 31, 2013, we have recorded total insurance recoveries of $505.0 million for the Line 6B crude oil release. We expect to record receivables for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

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

Enbridge's current comprehensive insurance program, under which we are insured, expired April 30, 2013 and had a current liability aggregate limit of $660.0 million, including sudden and accidental pollution liability. Enbridge has renewed its comprehensive property and liability insurance programs effective May 1, 2013 through April 30, 2014. The renewed coverage for the liability program is an aggregate limit of $685.0 million. In the unlikely event multiple insurable incidents occur which exceed coverage limits 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 the Partnership has entered into with Enbridge and another Enbridge subsidiary.

Legal and Regulatory Proceedings

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

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 30 actions or claims have been filed against us and our affiliates, in state and federal courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, we do not expect the outcome of these actions to be material. On July 2, 2012, PHMSA announced a Notice of Probable Violation, or NOPV, related to the Line 6B crude oil release, including a civil penalty of $3.7 million that we paid during the third quarter of 2012.

Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim has been filed against us and our affiliates by the State of Illinois in Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order. The costs associated with this order are included in the estimated environmental costs accrued for the Line 6A crude oil release. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

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

10. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility of our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 2016 in accordance with our risk management policies.

Accounting Treatment

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply the market approach to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in “Operating revenue,” “Cost of natural gas” and “Power” for our commodity-based derivatives and “Interest expense” for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in “Accumulated other comprehensive income,” also referred to as AOCI, a component of “Partners’ capital,” until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge’s change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in “Cost of natural gas” for commodity hedges and “Interest expense” for interest rate hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have transaction types associated with our commodity and interest rate derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in “Cost of natural gas,” “Operating revenue”, “Power” or “Interest expense” in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

- **Transportation**—In our Marketing segment, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

- **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the natural gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

- **NGL Collars—**In our Natural Gas segment, we entered into NGL collars to hedge the sales price of NGLs. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to greater volatility due to movements in the prices of NGLs until the underlying transactions are settled.

- **Optional Natural Gas Processing Volumes—**In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

- **NGL Forward Contracts—**In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts with terms allowing for economic net settlement do not qualify for the normal purchases and normal sales, or NPNS, scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.

- **Natural Gas Forward Contracts**—In our Marketing segment, we use forward contracts to sell natural gas to our customers. A sub-group of physical natural gas sales contracts with terms allowing for economic net settlement do not qualify for the NPNS scope exception, and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Crude Oil Contracts**—In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.
- **Power Purchase Agreements**—In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Except for physical power, in all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as follows:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- Corporate interest rate derivatives—"Interest expense"

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

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions)	
Liquids segment		
Non-qualified hedges	$(2.0)	$(8.8)
Natural Gas segment		
Hedge ineffectiveness	0.5	(1.8)
Non-qualified hedges	0.8	5.5
Marketing		
Non-qualified hedges	(2.8)	(1.8)
Commodity derivative fair value net losses	(3.5)	(6.9)
Corporate		
Hedge ineffectiveness	(0.5)	0.1
Non-qualified interest rate hedges	(0.2)	(0.1)
Derivative fair value net losses	$(4.2)	$(6.9)

Derivative Positions

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

	March 31, 2013	December 31, 2012
	(in millions)	
Other current assets	$ 20.9	$ 28.3
Other assets, net	20.7	15.8
Accounts payable and other	(243.6)	(256.7)
Other long-term liabilities	(54.9)	(68.3)
	$(256.9)	$(280.9)

The changes in the net 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 long-term natural gas, NGL and crude oil sales and purchase contracts.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $40.5 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the three month period ended March 31, 2013, no unrealized commodity hedge amounts were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $238.8 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at March 31, 2013, will be reclassified from AOCI to earnings during the next 12 months.

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

	March 31, 2013	December 31, 2012
	(in millions)	
Counterparty Credit Quality*		
AA	$(105.5)	$(116.5)
A	(155.8)	(147.7)
Lower than A	4.4	(16.7)
	$(256.9)	$(280.9)

* 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, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We would include any cash collateral received in the balances listed above, however, as of March 31, 2013 and December 31, 2012 we are holding no cash collateral on our asset exposures. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

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 to the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at March 31, 2013, we would have been required to provide additional letters of credit in the amount of $54.4 million.

At March 31, 2013 and December 31, 2012, we had credit concentrations in the following industry sectors, as presented below:

	March 31, 2013	December 31, 2012
	(in millions)	
United States financial institutions and investment banking entities	$(191.0)	$(204.5)
Non-United States financial institutions	(70.6)	(84.6)
Other	4.7	8.2
	$(256.9)	$(280.9)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $188.5 million and $231.2 million relating to our liability exposures pursuant to the margin thresholds in effect at March 31, 2013 and December 31, 2012, respectively, under our ISDA® agreements.

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 derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. A reconciliation between the derivative balances presented at gross values rather than the net amounts we present in our other derivative disclosures, is also provided below.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Asset Derivatives			Liability Derivatives		
		Fair Value at			Fair Value at	
	Financial Position Location	March 31, 2013	December 31, 2012	Financial Position Location	March 31, 2013	December 31, 2012
			(in millions)			
Derivatives designated as hedging instruments [1]						
Interest rate contracts	Other current assets	$ —	$ —	Accounts payable and other	$(233.3)	$(246.9)
Interest rate contracts	Other assets, net	11.8	6.0	Other long-term liabilities	(59.3)	(68.3)
Commodity contracts	Other current assets	12.0	16.8	Accounts payable and other	(10.0)	(9.9)
Commodity contracts	Other assets, net	6.0	4.5	Other long-term liabilities	(3.2)	(5.5)
		29.8	27.3		(305.8)	(330.6)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	1.0	2.4	Accounts payable and other	(0.9)	(2.2)
Commodity contracts	Other current assets	25.1	28.8	Accounts payable and other	(16.5)	(17.5)
Commodity contracts	Other assets, net	12.4	13.3	Other long-term liabilities	(2.0)	(2.4)
		38.5	44.5		(19.4)	(22.1)
Total derivative instruments		$68.3	$71.8		$(325.2)	$(352.7)

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

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

Derivatives in Cash Flow Hedging Relationships	Amount of gain (loss) recognized in AOCI on Derivative (Effective Portion)	Location of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Amount of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Location of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [1]	Amount of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [1]
		(in millions)			
For the three month period ended March 31, 2013					
Interest rate contracts . .	$28.9	Interest expense	$ (7.5)	Interest expense	$(0.5)
Commodity contracts . .	(1.6)	Cost of natural gas	1.5	Cost of natural gas	0.5
Total	$27.3		$ (6.0)		$—
For the three month period ended March 31, 2012					
Interest rate contracts . .	$43.6	Interest expense	$ (7.2)	Interest expense	$ 0.1
Commodity contracts . .	(3.9)	Cost of natural gas	(6.6)	Cost of natural gas	(1.9)
Total	$39.7		$(13.8)		$(1.8)

(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
	(in millions)
Balance at December 31, 2012	$(320.5)
Other Comprehensive Income before reclassifications	23.7
Amounts reclassified from AOCI [1]	6.0
Net Other Comprehensive Income	$ 29.7
Balance at March 31, 2013	$(290.8)

(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

	March 31, 2013	March 31, 2012
	(in millions)	
Losses (gains) on cash flow hedges:		
Interest Rate Contracts [1]	$ 7.5	$ 7.2
Commodity Contracts [2]	(1.5)	6.6
Total Reclassifications from AOCI	$ 6.0	$13.8

(1) Loss (gain) reported within "Interest expense" in the Consolidated Statements of Income.

(2) Loss (gain) reported within "Cost of natural gas" in the Consolidated Statements of Income.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	For the three month period ended March 31, 2013	2012
		Amount of Gain or (Loss) Recognized in Earnings [1]	
		(in millions)	
Interest rate contracts	Interest expense	$(0.2)	$(0.1)
Commodity contracts	Operating revenue	(2.3)	(8.5)
Commodity contracts	Power	0.3	(0.3)
Commodity contracts	Cost of natural gas	(2.0)	3.7
Total		$(4.2)	$(5.2)

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

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	March 31, 2013			December 31, 2012		
	Assets	Liabilities	Total	Assets	Liabilities	Total
	(in millions)					
Fair value of derivatives—gross presentation	$ 68.3	$(325.2)	$(256.9)	$ 71.8	$(352.7)	$(280.9)
Effects of netting agreements	(26.7)	26.7	—	(27.7)	27.7	—
Fair value of derivatives—net presentation	$ 41.6	$(298.5)	$(256.9)	$ 44.1	$(325.0)	$(280.9)

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 net basis by counterparty. The terms of the ISDA, which governs 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.

Offsetting of Financial Assets and Derivative Assets

	As of March 31, 2013				
	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	$68.3	$(26.7)	$41.6	$(1.1)	$40.5
Total	$68.3	$(26.7)	$41.6	$(1.1)	$40.5

Offsetting of Financial Liabilities and Derivative Liabilities

	As of March 31, 2013				
	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	$(325.2)	$26.7	$(298.5)	$1.1	$(297.4)
Total	$(325.2)	$26.7	$(298.5)	$1.1	$(297.4)

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 March 31, 2013 and December 31, 2012. 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.

	March 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Interest rate contracts	$—	$(280.7)	$ —	$(280.7)	$—	$(309.0)	$ —	$(309.0)
Commodity contracts:								
Financial	—	2.8	11.3	14.1	—	7.2	8.4	15.6
Physical	—	—	4.5	4.5	—	—	6.1	6.1
Commodity options	—	—	5.2	5.2	—	—	6.4	6.4
Total	$—	$(277.9)	$21.0	$(256.9)	$—	$(301.8)	$20.9	$(280.9)

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs, Crude and Power) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would change the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at March 31, 2013 [(2)]	Valuation Technique	Unobservable Input	Range [(1)] Lowest	Range [(1)] Highest	Range [(1)] Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$ 4.6	Market Approach	Forward Gas Price	3.81	4.45	4.12	MMBtu
NGLs	$ 6.7	Market Approach	Forward NGL Price	0.30	2.15	1.32	Gal
Commodity Contracts - Physical							
Natural Gas	$ 0.6	Market Approach	Forward Gas Price	3.80	4.61	4.14	MMBtu
Crude Oil	$ 1.8	Market Approach	Forward Crude Price	87.80	121.04	88.40	Bbl
NGLs	$ 3.1	Market Approach	Forward NGL Price	0.02	2.37	0.71	Gal
Power	$ (1.0)	Market Approach	Forward Power Price	31.55	38.86	34.46	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 5.2	Option Model	Option Volatility	33%	108%	41%	
Total Fair Value	$21.0						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas, dollars per Gallon, or Gal, for NGLs, dollars per barrel, or Bbl, for Crude Oil and dollars per Megawatt hour, or MWh, for Power.

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.3 million of losses.

Contract Type	Fair Value at December 31, 2012 [(2)]	Valuation Technique	Unobservable Input	Range [(1)] Lowest	Range [(1)] Highest	Range [(1)] Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$ 8.8	Market Approach	Forward Gas Price	3.21	4.31	3.54	MMBtu
NGLs	$ (0.4)	Market Approach	Forward NGL Price	0.25	2.21	1.40	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.6	Market Approach	Forward Gas Price	3.19	4.58	3.73	MMBtu
Crude Oil	$ 2.6	Market Approach	Forward Crude Price	65.22	116.56	94.31	Bbl
NGLs	$ 3.1	Market Approach	Forward NGL Price	—	2.22	0.61	Gal
Power	$ (1.2)	Market Approach	Forward Power Price	30.09	36.35	32.74	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 6.4	Option Model	Option Volatility	29%	104%	40%	
Total Fair Value	$20.9						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas, dollars per Gallon, or Gal, for NGLs, dollars per barrel, or Bbl, for Crude Oil and dollars per Megawatt hour, or MWh, for Power.

(2) Fair values are presented in millions and include credit valuation adjustments of approximately $0.2 million of losses.

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2013 to March 31, 2013. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
	(in millions)			
Beginning balance as of January 1, 2013	$ 8.4	$ 6.1	$ 6.4	$ 20.9
Transfer out of Level 3 (1)	—	—	—	—
Gains or losses				
Included in earnings (or changes in net assets)	2.0	8.9	(1.0)	9.9
Included in other comprehensive income	4.2	—	—	4.2
Purchases, issuances, sales and settlements				
Purchases	—	—	0.6	0.6
Settlements (2)	(3.3)	(10.5)	(0.8)	(14.6)
Ending balance as March 31, 2013	$11.3	$ 4.5	$ 5.2	$ 21.0
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ 5.5	$ 4.5	$(0.4)	$ 9.6

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

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

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2013 and December 31, 2012.

	At March 31, 2013						At December 31, 2012	
			Wtd. Average Price [2]		Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	1,932,100	$ 3.99	$ 3.54	$ 0.9	$(0.1)	$ 0.2	$(0.3)
	NGL	603,000	$ 53.94	$50.61	$ 2.0	$—	$ 1.4	$—
	Crude Oil	—	$ —	$ —	$—	$—	$ 0.2	$—
Receive fixed/pay variable	Natural Gas	3,634,500	$ 4.92	$ 4.05	$ 3.6	$(0.4)	$ 7.8	$—
	NGL	2,318,125	$ 53.01	$52.03	$ 8.0	$(5.7)	$ 9.3	$(9.9)
	Crude Oil	1,320,225	$ 92.00	$96.79	$ 3.1	$(9.4)	$ 6.3	$(8.8)
Receive variable/pay variable	Natural Gas	40,361,000	$ 4.05	$ 4.03	$ 1.0	$(0.1)	$ 1.2	$(0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	830,000	$ 40.87	$36.72	$ 3.9	$(0.5)	$ 0.6	$(0.8)
	Crude Oil	126,000	$ 97.33	$96.14	$ 0.3	$(0.1)	$ 0.4	$(0.4)
Receive fixed/pay variable	NGL	1,593,115	$ 39.04	$40.87	$ 0.5	$(3.4)	$ 2.6	$(2.2)
	Crude Oil	195,000	$ 95.72	$97.42	$ 0.1	$(0.5)	$ 0.2	$(1.0)
Receive variable/pay variable	Natural Gas	38,822,722	$ 4.06	$ 4.05	$ 0.6	$(0.5)	$ 0.9	$—
	NGL	7,164,820	$ 40.23	$39.85	$ 5.4	$(2.7)	$ 5.2	$(2.3)
	Crude Oil	1,167,990	$100.18	$98.52	$ 4.4	$(2.4)	$ 6.4	$(3.0)
Pay fixed	Power [4]	32,345	$ 34.42	$42.82	$—	$(0.3)	$—	$(0.5)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 4.31	$ 5.22	$—	$—	$—	$—
	NGL	60,000	$ 82.95	$85.26	$—	$(0.1)	$—	$—
Receive fixed/pay variable	Natural Gas	2,496,900	$ 4.01	$ 4.20	$—	$(0.5)	$ 0.2	$—
	NGL	892,425	$ 63.63	$62.10	$ 3.0	$(1.6)	$ 0.9	$(2.7)
	Crude Oil	1,361,955	$ 94.22	$92.79	$ 5.1	$(3.1)	$ 5.4	$(2.7)
Receive variable/pay variable	Natural Gas	8,112,500	$ 4.31	$ 4.30	$ 0.2	$(0.1)	$ 0.1	$(0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	21,409,275	$ 4.33	$ 4.32	$ 0.5	$(0.4)	$ 0.5	$—
	NGL	4,182,500	$ 18.23	$18.27	$—	$(0.2)	$—	$—
Pay fixed	Power [4]	58,608	$ 34.48	$46.58	$—	$(0.7)	$—	$(0.8)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$77.40	$ 1.2	$—	$ 0.7	$(0.2)
	Crude Oil	865,415	$ 97.72	$89.33	$ 7.3	$(0.1)	$ 6.8	$(0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,468,425	$ 4.34	$ 4.30	$ 0.4	$(0.1)	$ 0.4	$—
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$86.97	$ 0.6	$—	$ 0.5	$—
Physical Contracts								
Receive variable/pay variable	Natural Gas	783,240	$ 4.50	$ 4.38	$ 0.1	$—	$ 0.1	$—

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2013 and December 31, 2012, 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 adjustments of approximately $0.5 million of losses at March 31, 2013 and $0.4 million of losses at December 31, 2012.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at March 31, 2013 and December 31, 2012.

	At March 31, 2013						At December 31, 2012	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2013								
Puts (purchased)	Natural Gas	1,237,500	$ 4.18	$ 3.99	$ 0.5	$—	$ 1.4	$—
	NGL	367,000	$31.90	$28.34	$ 2.7	$—	$ 3.7	$—
Portion of option contracts maturing in 2014								
Puts (purchased)	NGL	264,250	$52.46	$50.87	$ 2.4	$—	$ 1.3	$—
Calls (written)	NGL	136,500	$54.17	$40.34	$—	$(0.4)	$—	$—

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2013 and December 31, 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

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.

				Fair Value [2] at	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate [1]	March 31, 2013	December 31, 2012
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 600	4.15%	$ (16.7)	$ (22.6)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$ 125	4.35%	$ (0.9)	$ (2.2)
Interest Rate Swaps—Pay Float	Non-qualifying	$ 125	4.75%	$ 1.0	$ 2.4
Contracts maturing in 2014					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 200	0.56%	$ (0.5)	$ (0.6)
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.7)	$ (6.7)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (16.0)	$ (16.0)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ (1.7)	$ (1.8)
Contracts settling prior to maturity					
2012—Pre-issuance Hedges	Cash Flow Hedge	$ —	—	$ —	$(154.0)
2013—Pre-issuance Hedges	Cash Flow Hedge	$1,100	4.51%	$(227.1)	$ (84.4)
2014—Pre-issuance Hedges	Cash Flow Hedge	$ 750	3.15%	$ (36.7)	$ (45.3)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 15.7	$ 8.4

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

(2) The fair value is determined from quoted market prices at March 31, 2013 and December 31, 2012, 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 adjustments of approximately $8.8 million of gains at March 31, 2013 and $13.7 million of gains at December 31, 2012.

11. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the State of Texas.

We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. The Texas state income tax rate was 0.4% and 0.5% for the three month periods ended March 31, 2013 and 2012, respectively. Our income tax expense is $1.8 million and $2.1 million for the three month periods ended March 31, 2013 and 2012, respectively.

At March 31, 2013 and December 31, 2012, we have included a current income tax payable of $9.4 million and $7.7 million in "Property and other taxes payable," respectively. In addition, at March 31, 2013 and December 31, 2012, we have included a deferred income tax liability of $3.0 million in "Other long-term liabilities," on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

12. SEGMENT INFORMATION

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

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

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

	As of and for the three month period ended March 31, 2013				
	Liquids	Natural Gas	Marketing	Corporate [1]	Total
			(in millions)		
Total revenue	$ 332.9	$1,214.4	$407.8	$ —	$ 1,955.1
Less: Intersegment revenue	—	248.7	13.4	—	262.1
Operating revenue	332.9	965.7	394.4	—	1,693.0
Cost of natural gas	—	795.9	395.5	—	1,191.4
Environmental costs, net of recoveries	178.5	—	—	—	178.5
Operating and administrative	86.7	106.5	1.3	0.4	194.9
Power	33.6	—	—	—	33.6
Depreciation and amortization	56.8	35.4	—	—	92.2
	355.6	937.8	396.8	0.4	1,690.6
Operating income (loss)	(22.7)	27.9	(2.4)	(0.4)	2.4
Interest expense	—	—	—	76.4	76.4
Other income	—	—	—	8.1	8.1
Income (loss) from continuing operations before income tax expense	(22.7)	27.9	(2.4)	(68.7)	(65.9)
Income tax expense	—	—	—	1.8	1.8
Net income (loss)	(22.7)	27.9	(2.4)	(70.5)	(67.7)
Less: Net income attributable to the noncontrolling interest	—	—	—	15.6	15.6
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (22.7)	$ 27.9	$ (2.4)	$ (86.1)	$ (83.3)
Total assets [2]	$7,688.9	$5,113.0	$162.2	$115.8	$13,079.9
Capital expenditures (excluding acquisitions)	$ 346.2	$ 68.4	$ —	$ 2.5	$ 417.1

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

(2) Totals assets for our Natural Gas Segment includes our long term equity investment in the Texas Express Pipeline project.

	As of and for the three month period ended March 31, 2012				
	Liquids	Natural Gas	Marketing	Corporate [1]	Total
			(in millions)		
Total revenue	$ 322.6	$1,387.5	$336.4	$ —	$ 2,046.5
Less: Intersegment revenue	0.3	218.3	8.4	—	227.0
Operating revenue	322.3	1,169.2	328.0	—	1,819.5
Cost of natural gas	—	965.6	331.3	—	1,296.9
Environmental costs, net of recoveries	3.2	—	—	—	3.2
Operating and administrative	77.2	117.6	1.7	0.4	196.9
Power	41.2	—	—	—	41.2
Depreciation and amortization	50.5	33.1	—	—	83.6
	172.1	1,116.3	333.0	0.4	1,621.8
Operating income (loss)	150.2	52.9	(5.0)	(0.4)	197.7
Interest expense	—	—	—	83.6	83.6
Income (loss) from continuing operations before income tax expense	150.2	52.9	(5.0)	(84.0)	114.1
Income tax expense	—	—	—	2.1	2.1
Net income (loss)	150.2	52.9	(5.0)	(86.1)	112.0
Less: Net income attributable to the noncontrolling interest	—	—	—	13.0	13.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 150.2	$ 52.9	$ (5.0)	$ (99.1)	$ 99.0
Total assets [2]	$6,234.7	$4,717.3	$130.0	$166.2	$11,248.2
Capital expenditures (excluding acquisitions)	$ 144.6	$ 114.0	$ —	$ 2.7	$ 261.3

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

(2) For comparability purposes, we have made reclassifications of approximately $38.3 million out of Total Corporate assets into Total Natural Gas assets for the March 31, 2012 balances. The reclassification represents our long term equity investment in the Texas Express Pipeline project as of March 31, 2012.

13. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative accounting provisions applicable to the regulated operations of our Southern Access and Alberta Clipper pipelines. The rates for both the Southern Access and Alberta Clipper pipelines are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls annually based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year, which is trued-up in the following year. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with the FERC and through toll rate adjustments with our customers. The assets and liabilities that we recognize for regulatory purposes are recorded in "Other current assets" and "Accounts payable and other," respectively, on our consolidated statements of financial position.

Southern Access Pipeline

For the three month period ended March 31, 2013, we had a net under collection of revenue for our Southern Access Pipeline primarily due to operating costs being higher than the forecasted costs used to calculate the toll surcharge in effect. As a result, for the three month period ended March 31, 2013, we adjusted our revenues by a net increase of $2.7 million on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at March 31, 2013 for the differences in these costs. The amounts will be included in our tolls beginning April 2014 when we update our transportation rates to account for the higher than forecasted costs.

For 2012, we under collected revenue for our Southern Access Pipeline primarily due to favorable power cost adjustments, partially offset by actual volumes being higher than the forecast volumes used to calculate the toll surcharge. As a result, in 2012, we increased our revenues for the amounts we under collected and recorded a regulatory asset. We began to amortize this regulatory asset on a straight line basis during 2013 to recognize the amounts we previously under collected. For the three month period ended March 31, 2013, we decreased our revenues by $0.5 million, on our consolidated statement of income with a corresponding amount increasing the regulatory liability on our consolidated statement of financial position at March 31, 2013. At March 31, 2013 and December 31, 2012, we had a $0.2 million and $0.7 million regulatory asset, respectively, on our consolidated statements of financial position related to this under collection. We began to recover these amounts from our customers when we updated our transportation rates to account for the lower costs and higher delivered volumes than estimated starting in April 2013.

Alberta Clipper Pipeline

For 2013, we have over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. As a result, for the three month period ended March 31, 2013, we decreased our revenues by $1.2 million on our consolidated statement of income with a corresponding increase in the regulatory liability on our consolidated statement of financial position at March 31, 2013 for the differences in transportation volumes. The amounts will be refunded through our tolls beginning April 2014 when we update our transportation rates to account for the higher delivered volumes.

During 2012, we over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than forecasted volumes used to calculate the toll charge. As a result, in 2012 we reduced our revenues for the amounts we over collected and recorded a regulatory liability. We began to amortize this regulatory liability on a straight line basis during 2013 to recognize the amounts we previously over collected. For the three month period ended March 31, 2013, we increased our revenues by $4.5 million, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position at March 31, 2013. As of March 31, 2013 and December 31, 2012, we had regulatory liabilities of $11.8 million and $16.3 million, respectively, in our consolidated statements of financial position for the difference in volumes. The amounts are being refunded to our customers through transportation rates, which became effective in April 2013.

Other Contractual Obligations

Southern Access Pipeline

We have entered into certain contractual obligations with our customers on the Southern Access Pipeline in which a portion of the revenue earned on volumes above certain predetermined shipment levels, or qualifying volumes, are returned to the shippers through future rate adjustments. We record the assets and liabilities associated with this contractual obligation in “Other current assets” and “Accounts payable and other,” respectively, on our consolidated statements of financial position. We amortize this contractual obligation on a straight line basis in the following year. At March 31, 2013 and December 31, 2012, we had $14.0 million and $12.4 million, respectively, in qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position.

For 2012, we also incurred liabilities related to contractual obligations with our customers on the Southern Access Pipeline related to qualifying volumes. As a result, in 2012 we reduced our revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortize the liability on a straight line basis in the following year. For the three month periods ended March 31, 2013 and 2012, we increased our revenues by $3.0 million and $1.0 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Alberta Clipper Pipeline

A portion of the rates we charge our customers includes an estimate for annual property taxes. If the estimated property tax we collect from our customers is significantly higher than the actual property tax imposed, we are contractually obligated to refund 50% of the property tax over collection to our customers. At March 31, 2013 and December 31, 2012, we had $6.2 million and $6.0 million, respectively, in property tax over collection liabilities related to our Alberta Clipper Pipeline on our statements of financial position.

For 2012, we also incurred liabilities related to this contractual obligation on the Alberta Clipper Pipeline. As a result, in 2012, we reduced revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortize the liability on a straight line basis in the following year. For the three month periods ended March 31, 2013 and 2012, we increased our revenues by $1.5 million and $1.8 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Regulatory Liability for Southern Lights Pipeline In-Service Delay

In December 2006, as part of the regulatory approval process for its pipeline, Enbridge Pipelines (Southern Lights) L.L.C., or Southern Lights, agreed to the request made by the Canadian Association of Petroleum Producers, referred to as CAPP, to delay the in-service date of its pipeline from January 1, 2010 to July 1, 2010. In exchange for Southern Light's postponement of the in-service date of its pipeline, CAPP agreed to reimburse Southern Lights for any carrying costs incurred during this period as a result of the delayed in-service date. The carrying costs were collected by us through the transportation rates charged on our Lakehead system beginning on April 1, 2010 and passed through to Southern Lights. Beginning in the second quarter 2012, we updated the transportation rates on our Lakehead system and began to reduce the transportation rates we charge the shippers to refund the excess amounts we collected. As of March 31, 2013, we had $1.4 million recorded as a regulatory liability on our consolidated statement of financial position for amounts we over collected in connection with the Southern Lights in-service delay. These amounts were not reflected in our revenues.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Line 6B Expansion and Mainline Expansion Project, we recorded $7.8 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at March 31, 2013, and a corresponding $7.8 million of "Other income" in our consolidated statement of income for the three month period ended March 31, 2013, with no similar transactions in the same period of 2012.

FERC Transportation Tariffs

Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilizes the System Expansion Project II, or SEP II, and the Facility Surcharge Mechanism, or FSM, which are components of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing increased the average transportation rate for crude oil movements from the Canadian border to the Chicago, Illinois area by an average of approximately $0.26 per barrel, to an average of approximately $1.93 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on 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.

Effective April 1, 2013, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. These expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.55 per barrel, to an average of approximately $2.06 per barrel.

Effective April 1, 2012, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2012 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. Also included was recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order.

The tariff rate is applicable to each barrel of crude oil that is delivered on our system on or after the effective date of the tariff. This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.22 per barrel.

Effective July 1, 2012, we filed FERC tariffs for our Lakehead, North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.086011, which was issued by FERC on May 15, 2012, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with FERC filing 18 C.F.R.3423 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by approximately $0.07 per barrel.

The April 1, 2012 and July 1, 2012 tariff changes decreased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.15 per barrel, to an average of approximately $1.67 per barrel.

14. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled “Other” in the “Cash from operating activities” section our consolidated statements of cash flows.

	For the three month period ended March 31,	
	2013	2012
	(in millions)	
Discount accretion	$ 0.2	$ 0.1
Amortization of debt issuance and hedging costs	2.1	3.3
Deferred income taxes	0.1	(0.1)
Impairment of Marshall homes	2.7	—
Allowance for equity used during construction	(7.8)	—
Allowance for interest used during construction	(2.8)	—
Loss on sale of assets	1.1	—
Other	0.2	(0.5)
	$(4.2)	$ 2.8

15. SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2013, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2013. The distribution will be paid to unitholders of record as of May 8, 2013, of our available cash of $206.2 million at March 31, 2013, or $0.5435 per limited partner unit. Of this distribution, $177.2 million will be paid in cash, $28.4 million will be distributed in i-units to our i-unitholder, Enbridge Management, and $0.6 million will be retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series AC Interests

On April 30, 2013, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series AC interests, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $14.9 million to the noncontrolling interest in the Series AC, while $7.5 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.

RESULTS OF OPERATIONS—OVERVIEW

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

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the three month periods ended March 31, 2013 and 2012.

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions)	
Operating Income (loss)		
Liquids	$(22.7)	$150.2
Natural Gas	27.9	52.9
Marketing	(2.4)	(5.0)
Corporate, operating and administrative	(0.4)	(0.4)
Total Operating Income	2.4	197.7
Interest expense	76.4	83.6
Other income	8.1	—
Income tax expense	1.8	2.1
Net income (loss)	(67.7)	112.0
Less: Net income attributable to noncontrolling interest	15.6	13.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$(83.3)	$ 99.0

Contractual arrangements in our Liquids, Natural Gas and Marketing segments expose us to market risks associated with changes in commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be significant if commodity prices experience significant volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in crude oil, natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The operating income of our Liquids business decreased $172.9 million for the three month period ended March 31, 2013, when compared to the same period of 2012, primarily due to the following:

- Increased environmental expense of $175.3 million for the three month period ended March 31, 2013, as compared with the same period in 2012, primarily due to increased expenses of $175.0 million for additional work required by the Environmental Protection Agency, or the EPA, relating to the Line 6B crude oil release;
- Decreased operating revenue of $13.9 million for the three month period ended March 31, 2013, when compared to the same period of 2012, primarily due to a decrease in average daily delivery volumes on our North Dakota system;
- Increased operating and administrative expenses of $9.5 million for the three month period ended March 31, 2013, when compared to the same period in 2012, primarily due to additional workforce related costs and increased property tax expenses; and
- Increased depreciation expense of $6.3 million for the three month period ended March 31, 2013, when compared to the same period in 2012, directly attributable to additional assets place into service.

The above factors were partially offset by the following:

- Increased operating revenue of $8.3 million for the three month period ended March 31, 2013, when compared to the same period in 2012, due to higher indexed tariff rates for our Lakehead, North Dakota and Ozark systems;
- Increased operating revenue of $7.7 million due to the collection of fees from our Cushing storage terminal facilities;
- Decreased power costs of $7.6 million due to decreased average daily delivery volumes on our systems for the three month period ended March 31, 2013, when compared to the same period in 2012; and
- Decreased unrealized, non-cash, mark-to-market net losses of $6.2 million for the three month period ended March 31, 2013, when compared to the same period in 2012, related to derivative financial instruments.

Natural Gas

The operating income of our Natural Gas business for the three month period ended March 31, 2013 decreased $25.0 million, as compared with the same period in 2012, primarily due to the following:

- Decreased gross margin of approximately $24.0 million due to the significant decline in NGL prices when compared to the same period in 2012;
- Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings of $13.0 million due to a decline in total NGL production and lower NGL prices when compared to the same period in 2012;
- Decreased operating income of $2.4 million in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment, when compared to the same period in 2012; and
- Increased depreciation expense of $2.3 million, as compared with the same period in 2012, due to additional assets that were put in service during 2012.

The above factors were partially offset by decreased operating and administration costs of $11.1 million for the three month period ended March 31, 2013, as compared with the same period in 2012 primarily due to:

- Decreased current year costs of $7.4 million for the investigation costs related to accounting misstatements at our trucking and NGL marketing subsidiary recorded in 2012, with no similar costs recorded during 2013;
- Decreased supporting costs of $5.1 million due to favorable maintenance, supplies and other outside services requirements when compared to 2012; and
- Increased integrity costs of $1.5 million as part of the operational risk management plan to ensure our systems are safe and to maintain our existing pipelines.

Marketing

The operating loss of our Marketing segment for the three month period ended March 31, 2013 decreased $2.6 million compared to the same period in 2012, primarily due to no non-cash charges to inventory for the three month period ended March 31, 2013, compared to $2.0 million for the three month period ended March 31, 2012, which we recorded to reduce the cost basis of our natural gas inventory to net realizable value.

Also contributing to the decrease in operating loss was the expiration of certain transportation fees for natural gas being transported on a third party pipeline. These transportation fees which expired, effective June 30, 2012, reduced natural gas expense by approximately $1.0 million for the three month period ended March 31, 2013, as compared to the same period in 2012.

Offsetting these reductions to operating losses in our Marketing segment was an increase of $1.0 million in unrealized, non-cash, mark-to-market net losses, for the three month period ended March 31, 2013, compared to the same period in 2012, attributable to financial instruments used to hedge our storage positions.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates and to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates. We record all derivative 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 qualify for hedge accounting in our consolidated statements of income as follows:

- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Corporate interest rate derivatives—"Interest expense"

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

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions)	
Liquids segment		
Non-qualified hedges	$(2.0)	$(8.8)
Natural Gas segment		
Hedge ineffectiveness	0.5	(1.8)
Non-qualified hedges	0.8	5.5
Marketing		
Non-qualified hedges	(2.8)	(1.8)
Commodity derivative fair value net losses	(3.5)	(6.9)
Corporate		
Hedge ineffectiveness	(0.5)	0.1
Non-qualified interest rate hedges	(0.2)	(0.1)
Derivative fair value net losses	$(4.2)	$(6.9)

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	For the three month period ended March 31, 2013	2012
	(unaudited; in millions)	
Operating Results		
Operating revenues	$332.9	$322.3
Environmental costs, net of recoveries	178.5	3.2
Operating and administrative	86.7	77.2
Power	33.6	41.2
Depreciation and amortization	56.8	50.5
Operating expenses	355.6	172.1
Operating Income (loss)	$ (22.7)	$150.2
Operating Statistics		
Lakehead system:		
United States [(1)]	1,470	1,470
Province of Ontario [(1)]	366	391
Total Lakehead system deliveries [(1)]	1,836	1,861
Barrel miles (billions)	120	124
Average haul (miles)	726	732
Mid-Continent system deliveries [(1)]	222	236
North Dakota system:		
Trunkline [(1)]	124	219
Gathering [(1)]	4	3
Total North Dakota system deliveries [(1)]	128	222
Total Liquids Segment Delivery Volumes [(1)]	2,186	2,319

(1) Average barrels per day in thousands.

Three month period ended March 31, 2013 compared with three month period ended March 31, 2012

Our operating revenue of our Liquids segment was positively impacted by the filing of tariffs to increase the rates for our Lakehead, North Dakota and Ozark systems with Federal Energy Regulatory Commission, or FERC, that became effective July 1, 2012. These rate increases resulted from application of the index allowed by FERC. This change in index comprises approximately $8.3 million of the increase in operating revenue for the three month period ended March 31, 2013 when compared to the same period in 2012.

In addition, our operating revenue increased by $7.7 million during the three month period ended March 31, 2013 due to the collection of fees from our Cushing storage terminal facilities, with the majority of these incremental revenues coming from storage facilities which were placed into service during 2012.

The operating revenue also increased for the three month period ended March 31, 2013 when compared with the same period in 2012 partly due to a $6.2 million decrease in unrealized, non-cash, mark-to-market net losses related to derivative financial instruments as compared with the same period in 2012, due to decreases in average forward prices of crude oil for the respective periods. We use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We use derivative financial instruments which fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

Partially offsetting the increase to operating revenue was the lower average daily delivery volumes primarily on our North Dakota system. Operating revenue decreased by $13.9 million for the three month period ended March 31, 2013 when compared to the same period in 2012 as a result of this decrease in average daily volumes. The decrease in average deliveries on our North Dakota system was attributable to rail options available to shippers. This loss of volume was slightly offset by revenue from our Bakken expansion which has ship or pay agreements in place.

Environmental costs, net of recoveries increased $175.3 million for the three month period ended March 31, 2013 when compared with the same period in 2012, of which $175.0 million is primarily attributable to additional work required by the Order we received on March 14, 2013, related to the Line 6B crude oil release, which we refer to as the Order.

The operating and administrative expenses of our Liquids business increased $9.5 million for the three month period ended March 31, 2013 when compared with the same period in 2012 primarily due to additional workforce related costs of $7.2 million and increased property tax expenses of $3.7 million.

Power cost decreased $7.6 million for the year ended March 31, 2013, when compared to the same period in 2012, primarily due to decreased average daily delivery volumes on all of our system, as mentioned above.

The increase in depreciation expense of $6.3 million for the three month period ended March 31, 2013 is directly attributable to the additional assets we have placed in service since the same period in 2012.

Future Prospects Update for Liquids

The table below and discussion summarizes the Partnership's commercially secured projects for the Liquids segment, which will be placed into service in future periods.

Projects	Total Estimated Capital Costs	Expected In-Service Date	Funding
	(in millions)		
Eastern Access Projects			
Line 5, Line 62 Expansion, Line 6B Replacement	$2,050	2013—2014	Joint [(1)]
Eastern Access Upsize—Line 6B Expansion	365	Early 2016	Joint [(1)]
U.S. Mainline Expansions			
Line 67 & Line 61 (phase 1)	420	Q3 2014	Joint [(2)]
Chicago Area Connectivity (Line 62 twin)	495	Late 2015	Joint [(2)]
Line 61 (phase 2)	1,250	Mid 2015, 2016	Joint [(2)]
Line 67 (phase 3)	240	2015	Joint [(2)]
Bakken Access Program	100	Q2 2013	EEP
Sandpiper Project	2,500	Early 2016	EEP
Line 6B 75-mile Replacement Program	320	Q2-Q4 2013	EEP

(1) Jointly funded 40% by the Partnership and 60% by our General Partner under Eastern Access Joint Funding agreement. Estimated capital costs presented are before our General Partner's contributions.

(2) Jointly funded 40% by the Partnership and 60% by our General Partner under Mainline Expansion Joint Funding agreement. Estimated capital costs presented are before our General Partner's contributions.

Light Oil Market Access Program

On December 6, 2012, we and Enbridge announced our plans to invest in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant recent developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries.

Sandpiper Project

Included in the Light Oil Market Access Program is the Sandpiper Project which will expand and extend the North Dakota feeder system by 225,000 Bpd to a total of 580,000 Bpd. The expansion will involve construction of an approximately 600-mile 24-inch diameter line from Beaver Lodge, North Dakota, to the Superior, Wisconsin, mainline system terminal. The new line will twin the 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 225,000 Bpd of capacity on the twin line between Beaver Lodge and Clearbrook and 375,000 Bpd between Clearbrook and Superior.

The Sandpiper Project is estimated to cost approximately $2.5 billion and will be fully funded by the Partnership. We filed a petition with the FERC to approve recovering Sandpiper's costs through a surcharge to the Enbridge Pipelines (North Dakota) LLC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. On March 22, 2013, FERC denied the petition on procedural grounds. We plan to re-file the petition with modifications to address the FERC's concerns. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals, as well as, finalization of scope.

Eastern Access Projects

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the United States Upper Midwest and in Canada in the provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. One of the projects involves the expansion of the Partnership's Line 5 light crude line between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd. The Line 5 expansion is targeted to be in service during the second quarter of 2013. In May 2012, we and Enbridge announced further plans to expand access to Eastern markets. The projects to be pursued by the Partnership include: (1) expansion of the Spearhead North pipeline, or Line 62, between Flanagan, Illinois and the Terminal at Griffith, Indiana by adding horsepower to increase capacity from 130,000 Bpd to 235,000 Bpd, and an additional 330,000 barrel crude oil tank at Griffith; and (2) replacement of additional sections of the Partnership's Line 6B in Indiana and Michigan, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, to increase capacity from 240,000 Bpd to 500,000 Bpd. Portions of the existing 30-inch diameter pipeline will be replaced with 36-inch diameter pipe. Subject to regulatory and other approvals, these projects are expected to be placed in-service in late 2013 and 2014. These projects, including the previously announced Line 5 expansion, will cost approximately $2.1 billion and will be undertaken on a cost-of-service basis with shared capital cost risk, such that the toll surcharge will absorb 50% of any cost overruns over $1.85 billion during the Competitive Toll Settlement, or CTS, term, which is until July 2021.

As part of the Light Oil Market Access Program announced in December 2012, the Partnership will upsize the Eastern Access projects, which includes further expansion of the Line 6B component with increasing capacity from 500,000 Bpd to 570,000 Bpd and will involve the addition of new pumps, existing station modifications and breakout tankage at the Griffith and Stockbridge terminals, at an expected cost of approximately $365 million. This further expansion of the Line 6B component is expected to begin service in early 2016 subject to regulatory and other approvals.

These projects collectively referred to as the Eastern Access Projects, will cost approximately $2.4 billion and will be undertaken on a cost-of-service basis and will be funded 60% by our General Partner and 40% by the Partnership under an Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points.

U.S. Mainline Expansion

In May 2012, we also announced further expansion of our mainline pipeline system which included: (1) increasing capacity on the existing 36-inch diameter Alberta Clipper pipeline, or Line 67, between Neche, North Dakota into the Superior, Wisconsin Terminal from 450,000 Bpd to 570,000 Bpd; and (2) expanding of the existing 42-inch diameter Southern Access pipeline, or Line 61, between the Superior Terminal and the Flanagan Terminal near Pontiac, Illinois from 400,000 Bpd to 560,000 Bpd. These projects require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction, at a cost of approximately $420 million. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd, the expansions will be undertaken on a full cost-of-service basis and are expected to be available for service in third quarter of 2014, however, delays in receipt of the applicable regulatory approvals could affect the target in-service date.

As part of the Light Oil Market Access Program announced in December 2012, the capacity of our Lakehead System between Flanagan, Illinois, and Griffith, Indiana will be expanded by constructing a 76-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62, with an initial capacity of 570,000 Bpd, at an estimated cost of $495 million. Additionally, the capacity of our Southern Access pipeline, or Line 61, will be expanded to its full 1,200,000 Bpd potential and additional tankage requirements at an estimated cost of approximately $1.25 billion. Subject to finalization of scope, regulatory and other approvals, the expansions are expected to begin service in 2015, with additional tankage expected to be completed in 2016.

On January 4, 2013, we announced further expansion of our Alberta Clipper pipeline, or Line 67, which will add an additional 230,000 Bpd of capacity at an estimated cost of approximately $240 million. The expansion involves increased pumping horsepower, with no line pipe construction. Subject to regulatory and other approvals, the pipeline is expected for service in 2015, however, delays in receipt of the applicable regulatory approvals could affect the target in-service date.

These projects collectively referred to as the U.S. Mainline Expansions projects, will cost approximately $2.4 billion and will be undertaken on a cost-of-service basis. The projects will be jointly funded by our General Partner at 60% and the Partnership at 40%, under a Mainline Expansion Joint Funding Agreement which parallels the Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points.

The Eastern Access Projects and U.S. Mainline expansions complement Enbridge's strategic initiative of expanding access to new markets in North America for growing production from western Canada and the Bakken Formation.

Since October 2011, Enbridge, the ultimate parent of our General Partner, also announced several complementary Eastern Access and Mainline Expansion Projects. These projects include: (1) reversal of Enbridge's Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario; (2) construction of a 35-mile pipeline adjacent to Enbridge's Toledo Pipeline, originating at the Partnership's Line 6B in Michigan to serve refineries in Michigan and Ohio; (3) reversal of Enbridge's Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec; (4) an expansion of Enbridge's Line

9B to provide additional delivery capacity within Ontario and Quebec; (5) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border; and (6) modifications to existing terminal facilities on the Enbridge Mainline system, comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections in order to accommodate additional light oil volumes and enhance operational flexibility. Several of the above projects remain subject to regulatory approval and have various targeted in-service dates from the second quarter of 2013 through 2015. These projects will enable growing light crude production from the Bakken shale and from Alberta to meet refinery needs in Michigan, Ohio, Ontario and Quebec. These projects will also provide much needed transportation outlets for light crude, mitigating the current discounting of supplies in the basins, while also providing more favorable supply costs to refiners currently dependent on crudes priced off of the Atlantic basin.

Berthold Rail

In December 2011, we announced that we were proceeding with the Berthold Rail Project, an interim solution to shipper needs in the Bakken region. The project expands pipeline capacity into the Berthold, North Dakota Terminal by 80,000 Bpd and included the construction of a three unit-train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. During September 2012, the first phase of terminal facilities was completed, providing capacity of 10,000 Bpd to the Berthold Terminal. The final construction of the loading facility and the crude oil tankage (Phase II) were placed into service in March 2013. The estimated cost of the Berthold Rail Project is approximately $135 million.

Bakken Pipeline Expansion

In August 2010, we announced the Bakken Project, a joint crude oil pipeline expansion project with an affiliate of Enbridge in the Bakken and Three Forks formations located in the states of Montana and North Dakota and the Canadian provinces of Saskatchewan and Manitoba. The Bakken Project follows our existing rights-of-way in the United States and those of Enbridge Income Fund Holdings in Canada to terminate and deliver to the Enbridge Mainline system's terminal at Cromer, Manitoba, Canada. The United States portion of the Bakken Project expands the United States portion of the Portal Pipeline, which was reversed in 2011 in order to flow oil from Berthold to the United States border and on to Steelman, Saskatchewan, by constructing two new pumping stations in Kenaston and Lignite, North Dakota, and replacing an 11-mile segment of the existing 12-inch diameter pipeline that runs from these two locations. The project also called for an expansion at our existing terminal and station in Berthold, North Dakota. We commenced construction in July of 2011 and the Bakken Project was completed and placed into service in March 2013 providing capacity of 145,000 Bpd. This project, with the North Dakota mainline, results in a total takeaway capacity for this region of 355,000 Bpd. The United States portion of the Bakken Project had estimated cost of approximately $300 million. In February 2012, we and Enbridge Income Fund Holdings in Canada, announced a second open season for the Bakken Project to allow shippers the option of securing future capacity once the expansion is completed. The open season resulted in additional term commitments to support the Bakken Project.

Bakken Access Program

In October 2011, we announced the Bakken Access Program, a series of projects totaling approximately $100 million, which represents an upstream expansion that will further complement our Bakken Project, as discussed above. This expansion program will substantially enhance our gathering capabilities on the North Dakota system by 100,000 Bpd. This program is expected to be in service in the second quarter of 2013, and it involves increasing pipeline capacities, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota.

Line 6B 75-mile Replacement Program

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory and other approvals related to two 5-mile segments in Indiana, the new segments of pipeline are targeted to be placed in service in components from the second through the fourth quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. In 2012, we subsequently revised the scope of this project to increase the diameter of all pipe segments upstream of Stockbridge, Michigan. The total capital for this replacement program is estimated to cost $320 million. These costs will be recovered through our Facilities Surcharge Mechanism, or FSM, which is part of the system-wide rates of the Lakehead system.

Enbridge United States Gulf Coast Projects and Southern Access Extension

A key strength of the Partnership is our relationship with Enbridge. In 2011, Enbridge announced two major United States Gulf Coast market access pipeline projects, which when completed will pull more volume through the Partnership's pipeline, and may lead to further expansions of our Lakehead pipeline system. In addition, in 2012 Enbridge announced the Southern Access Extension, which will support the increasing supply of light oil from Canada and the Bakken.

Flanagan South Pipeline

Enbridge's Flanagan South Pipeline project will transport more volumes into Cushing, Oklahoma and twin its existing Spearhead pipeline, which starts at the hub in Flanagan, Illinois and delivers volumes into the Cushing hub. The 36-inch diameter pipeline will have an initial capacity of approximately 585,000 Bpd, and subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014.

Seaway Crude Pipeline

In 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Crude Pipeline System, or Seaway. Seaway is a 670-mile pipeline that includes a 500-mile, 30-inch pipeline long-haul system that was reversed in 2012 to enable transportation of oil from Cushing, Oklahoma to Freeport, Texas, as well as a Texas City Terminal and Distribution System which serves refineries in Houston and Texas City areas. Seaway also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and provided an initial capacity of 150,000 Bpd. Further pump station additions and modifications completed in January 2013, have increased the capacity to approximately 400,000 Bpd, depending upon the mix of light and heavy grades of crude oil. Actual throughput experienced to date in 2013 has been curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P.'s (Enterprise) ECHO crude oil terminal (ECHO Terminal) in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013. However, capacity is also expected to be limited by increased nominations of heavy crude oil until the Seaway Pipeline twin comes into service in the first quarter of 2014, as discussed below.

In March 2012, based on additional capacity commitments from shippers, plans were announced to proceed with an expansion of the Seaway Pipeline through construction of a second line that is expected to more than double its capacity to 850,000 Bpd by the first quarter of 2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. In addition, a proposed 85-mile pipeline is expected to be built from Enterprise Product's ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities. The new pipeline will offer incremental capacity of 560,000 Bpd, and subject to regulatory approval, is expected to be available in the first quarter of 2014.

Southern Access Extension

In December 2012, Enbridge announced that they will undertake the Southern Access Extension project, which will consist of the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, as well as additional tankage and two new pump stations. The initial capacity of the new line is expected to be approximately 300,000 Bpd. In addition, Enbridge announced a binding open season to solicit commitments from shippers for capacity on the proposed pipeline. While the binding open season that closed in January 2013 did not result in additional capacity commitments from shippers, Enbridge had previously received sufficient capacity commitments from an anchor shipper to support the 24-inch pipeline as proposed. Subject to regulatory and other approvals, the project is expected to be placed into service in 2015.

Other Matters

Line 14 Hydrostatic Test

After the July 27, 2012 release of crude oil on Line 14, the PHMSA issued a Corrective Action Order on July 30, 2012 and an amended Corrective Action Order on August 1, 2012, which we refer to as the PHMSA Corrective Action Order. The PHMSA Corrective Action Order required us to take certain corrective actions, some of which were already done during 2013 and some are still ongoing, as part of an overall plan for our Lakehead system. As part of this plan, we are planning to perform hydrostatic testing of Line 14 during the third quarter of 2013. We anticipate during this hydrostatic testing Line 14 will be unavailable for approximately 11 days to conduct the tests with an additional six days of capacity reduction for water movement. We do not expect this to have a material impact on our operating revenue for 2013. The costs associated with this hydrostatic testing will be collected through the Lakehead tariff during 2013 through 2014.

Natural Gas

The following tables set forth the operating results of our Natural Gas Segment assets and approximate average daily volumes of our major systems in millions of British Thermal Units, or MMBtu/d, for the periods presented.

	For the three month period ended March 31,	
	2013	**2012**
	(unaudited; in millions)	
Operating revenues	$ 965.7	$ 1,169.2
Cost of natural gas	795.9	965.6
Operating and administrative	106.5	117.6
Depreciation and amortization	35.4	33.1
Operating expenses	937.8	1,116.3
Operating Income	$ 27.9	$ 52.9
Operating Statistics (MMBtu/d)		
East Texas	1,252,000	1,319,000
Anadarko	964,000	942,000
North Texas	332,000	315,000
Total	2,548,000	2,576,000

Three month period ended March 31, 2013 compared with three month period ended March 31, 2012

The operating income of our Natural Gas business for the three month period ended March 31, 2013 decreased $25.0 million, as compared with the same period in 2012. The most significant area affected was Natural Gas gross margin, representing revenue less cost of natural gas, which decreased $33.8 million for the three month period ended March 31, 2013 as compared with the same period in 2012.

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We are exposed to fluctuations in commodity prices in the near term on approximately 30% to 40% of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our gross margin generally increases when the prices of these commodities are rising and generally decreases when the prices are declining. Prices for NGLs have declined significantly when compared to prices for the same period in 2012. NGLs declined approximately 11% and 27% per composite barrel, for the three month period ended March 31, 2013 as compared to the same period in 2012, based upon the Conway and Mont Belvieu pricing hubs, respectively.

Changing industry fundamentals have resulted in significant downward pressure in current and forward NGL prices, specifically in ethane and propane. As a result, some of our plants were periodically rejecting ethane and selling these molecules as natural gas. The near term outlook for our Natural Gas segment has been negatively impacted by this decline in NGL prices, resulting in a reduction of approximately $24.0 million to our gross margin for the three month period ended March 31, 2013 when compared to the same period in 2012.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended March 31, 2013 decreased $13.0 million from the same period in 2012. The decline in keep-whole earnings is the result of a decline in total NGL production, partially from the rejection of ethane as discussed above, and lower NGL prices for the three month period ended March 31, 2013 when compared to the same period in 2012.

Additionally, the operating results of our Natural Gas business experienced a decrease in unrealized, non-cash, mark-to-market net gains of $2.4 million for the three month period ended March 31, 2013 compared to the same period of 2012 due to increases in the average forward price of natural gas and overall physical commodity losses from the non-qualifying physical NGL and crude oil contracts. Partially offsetting these effects were fractionation margins, representing the relative difference between the price we receive from the sale of NGLs and condensate and the corresponding cost of natural gas we purchase for processing, narrowed during the first quarter of 2013, compared to the same period in 2012, as a result of higher natural gas forward prices.

The following table depicts the effect that unrealized, non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the three month periods ended March 31, 2013 and 2012:

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions)	
Hedge ineffectiveness	$0.5	$(1.8)
Non-qualified hedges	0.8	5.5
Derivative fair value gains	$1.3	$ 3.7

Operating and administrative costs of our Natural Gas segment decreased $11.1 million for the three month period ended March 31, 2013 compared to the same period in 2012, primarily due to decreased costs of $7.4 million for the investigation of accounting misstatements at our trucking and NGL marketing subsidiary recorded in 2012, with no similar costs recorded during 2013. Supporting costs also decreased $5.1 million due to favorable maintenance, supplies and other outside services requirements when compared to 2012. These factors were partially offset by increased pipeline integrity costs of $1.5 million as part of the operational risk management plan to ensure our systems are safe and to maintain our existing pipelines.

Depreciation expense for our Natural Gas segment increased $2.3 million, for the three month period ended March 31, 2013 compared with the same period of 2012, due to additional assets that were put in service during 2012.

Future Prospects for Natural Gas

The following table and discussion summarizes the Partnership's commercially secured projects for the Natural Gas segment, which will be placed into service in future periods.

Project	Estimated Capital Costs	Expected In-service Date	Funding
	(in millions)		
Beckville Cryogenic Processing Facility	$140	Early 2015	EEP
Texas Express Pipeline	$385	Q3 2013	Joint [1]
Ajax Cryogenic Processing Plant	$230	Q3 2013	EEP

(1) Our ownership of the Texas Express Pipeline is 35%. Estimated capital costs presented are only our portion of the costs.

Beckville Cryogenic Processing Facility

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville plant at an expected cost of approximately $140. The Beckville plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley Play region, where our East Texas system is located. The Beckville plant has a planned capacity of 150 MMcf/d. Construction of the Beckville Plant and associated facilities is anticipated to begin in late 2013 and is planned to be in-service by early 2015.

Texas Express Pipeline

In September 2011, we announced a joint venture among us, Enterprise Products, and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline and two new NGL gathering systems, collectively referred to as the Texas Express Pipeline project, or TEP. In April 2012, DCP Midstream LLC, or DCP, announced plans to purchase a 10% ownership in the NGL pipeline portion of TEP from Enterprise Products. After DCP's purchase, the NGL pipeline portion of TEP is owned 35% by Enterprise Products, 35% by us, 20% by Anadarko and 10% by DCP, while the ownership in the two new NGL gathering systems will be owned 45% by Enterprise Products, 35% by us and 20% by Anadarko. Our portion of the total estimated cost is $385 million. The pipeline will originate at Skellytown, Texas and extend approximately 580-miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. The pipeline will have an initial capacity of approximately 280,000 Bpd and will be readily expandable to approximately 400,000 Bpd. Approximately 250,000 Bpd of capacity has been subscribed on the pipeline.

In addition, the TEP joint venture project will include two new NGL gathering systems. The first will connect TEP NGL pipeline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and Western Oklahoma. The second NGL gathering system will connect the new pipeline to central Texas, Barnett Shale processing plants. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the TEP system utilizing Enterprise's existing Mid-America Pipeline assets between the Conway hub and Enterprise's Hobbs NGL fractionation facility in Gaines County, Texas. In addition, volumes from and to the Denver-Julesburg Basin in Weld County, Colorado will be able to access TEP through the connecting Front Range Pipeline as proposed by Enterprise Products, DCP and Anadarko. Enterprise Products will construct and serve as the operator of the pipeline, while we will build and operate the new gathering systems. The pipeline and portions of the gathering systems are expected to begin service in the third quarter of 2013, subject to regulatory approval.

TEP will serve as a link between growing supply sources of NGLs in the Anadarko region and the primary end use market on the United States Gulf Coast and will provide guaranteed NGL access to the primary United States petrochemical market located in Mont Belvieu. TEP will assist us in fulfilling our strategic objective of expanding our presence in the natural gas and NGL value chain and provide us with a new source of strong and stable cash flow.

Ajax Cryogenic Processing Plant

In August 2011, we announced plans to construct an additional processing plant and other facilities, including compression and gathering infrastructure, on our Anadarko system at a cost of $230 million, which we refer to as our Ajax Plant. The Ajax Plant has a planned capacity of 150 million cubic feet per day, or MMcf/d, and is intended to meet the continued strength of horizontal drilling activity in this area. The Ajax Plant will be available for service in the second quarter of 2013 and is anticipated to be placed into service in the third quarter of 2013, corresponding with the completion of TEP discussed above.

The Ajax plant, when operational, in addition to the Allison Plant, will increase the total processing capacity on our Anadarko system to approximately 1,200 MMcf/d.

Marketing

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

	For the three month period ended March 31,	
	2013	2012
	(unaudited; in millions)	
Operating revenues	$394.4	$328.0
Cost of natural gas	395.5	331.3
Operating and administrative	1.3	1.7
Operating expenses	396.8	333.0
Operating loss	$ (2.4)	$ (5.0)

Our Marketing business derives a majority of its operating income from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers utilizing the natural gas. A majority of the natural gas we purchase is produced in Texas markets where we have expanded access to several interstate natural gas pipelines over the past several years, which we can use to transport natural gas to primary markets where it can be sold to major natural gas customers.

Three month period ended March 31, 2013 compared with three month period ended March 31, 2012

The operating results of our Marketing segment for the three month period ended March 31, 2013 increased by $2.6 million when compared to the same period in 2012.

Operating results for the current year were positively affected by no non-cash charges to inventory for the three month period ended March 31, 2013, compared to $2.0 million for the three month period ended March 31, 2012, which we recorded to reduce the cost basis of our natural gas inventory to net realizable value. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

Also contributing to the increase in operating results of our Marketing segment, for the three month period ended March 31, 2013, was the expiration of certain transportation fees for natural gas being transported on a third party pipeline. These transportation fees expired, effective June 30, 2012, and reduced natural gas expense by approximately $1.0 million for the three month period ended March 31, 2013, as compared to the same period in 2012.

Operating income for the three month period ended March 31, 2013 was negatively affected by unrealized, non-cash, mark-to-market net losses of $2.8 million as compared with $1.8 million of unrealized non-cash, mark-to-market net losses for the same period in 2012 associated with derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. This increase in unrealized, non-cash, mark-to-market net losses for the three month period ended March 31, 2013, as compared to the same period in 2012, was primarily attributed to financial instruments used to hedge our storage positions. The net losses associated with our storage derivative instruments resulted from the widening difference between the natural gas injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas was sold from storage.

Corporate

Our corporate activities consist of interest expense, interest income, allowance for equity during construction, referred to as AEDC, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	For the three month period ended March 31,	
	2013	**2012**
	(unaudited; in millions)	
Operating and administrative expenses	$ 0.4	$ 0.4
Operating loss	(0.4)	(0.4)
Interest expense	76.4	83.6
Other income	8.1	—
Income tax expense	1.8	2.1
Net loss	(70.5)	(86.1)
Less: Net income attributable to noncontrolling interest	15.6	13.0
Net loss attributable to general and limited partners	$(86.1)	$(99.1)

Three month period ended March 31, 2013 compared with three month period ended March 31, 2012

The $15.6 million decrease in our net loss for the three month period ended March 31, 2013 as compared to the same period in 2012 was primarily attributable to a decrease in interest expense and an increase in AEDC.

Interest expense decreased $7.2 million for the three month period ended March 31, 2013, compared with the corresponding period in 2012, primarily due to an increase of $7.9 million in capitalized interest related to our capital projects. The increase in capitalized interest was offset by a $0.7 million increase in interest expense due to a higher commercial paper balance for the three month period ended March 31, 2013 as compared to the same period in 2012 partially offset by decreased weighted average interest rate. Our interest cost for the three month periods ended March 31, 2013 and 2012 is detailed below:

	For the three month period ended March 31,	
	2013	**2012**
	(unaudited; in millions)	
Interest expense	$76.4	$83.6
Interest capitalized	14.3	6.4
Interest cost incurred	$90.7	$90.0
Weighted average interest rate	6.1%	6.5%

Our net loss was further decreased by AEDC of $7.8 million primarily related to our Line 6B and Eastern Access projects for the three month period ended March 31, 2013, which is recorded in "Other income" in our consolidated statements of income.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge, including our General Partner. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $12.9 million and $13.0 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month periods ended March 31, 2013 and March 31, 2012, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, we amended and restated the partnership agreement of the OLP to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance the Eastern Access Projects. We allocated earnings from the Eastern Access Projects in the amount of $2.7 million to our General Partner for its 60% ownership of the EA interest for the period ended March 31, 2013. We have presented this amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had approximately $1.9 billion of liquidity available to us at March 31, 2013 to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental costs resulting from the crude oil release on Line 6B.

	(unaudited; in millions)
Cash and cash equivalents	$ 241.5
Total credit available under Credit Facilities [1]	3,100.0
Less: Amounts outstanding under Credit Facilities [1]	—
Principal amount of commercial paper issuances	1,300.0
Letters of credit outstanding	189.1
Total	$1,852.4

(1) We refer to the credit facility that we entered into in September 2011 and our 364-Day Credit Facility that we entered into on July 6, 2012 as our Credit Facilities.

General

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

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through organic growth and targeted acquisitions. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as, retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all. When we have attractive growth opportunities in excess of our own capital raising capabilities, the General Partner has provided supplementary funding, or participated directly in projects, to enable us to undertake such opportunities. If in the future we have attractive growth opportunities that exceed capital raising capabilities, we could seek similar arrangements from the General Partner or other alternative sources of financing, including monetization or disposition of non-core assets, but there can be no assurance that this funding can be obtained.

As of March 31, 2013, we had a working capital deficit of approximately $709.6 million and approximately $1.9 billion of liquidity to meet our ongoing operational, investing and finance needs as of March 31, 2013 as shown above, as well as the funding requirements associated with the environmental costs resulting from the crude oil releases on Line 6B.

Capital Resources

Equity and Debt Securities

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

Investments

In March 2013, Enbridge Management completed a public offering of 10,350,000 Listed Shares, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 per Listed Share. Enbridge Management received net proceeds of $272.9 million, which were subsequently invested in our i-units equal to the number of Listed Shares sold in the offering. We intend to use the proceeds from our issuance of i-units to Enbridge Management to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

The following table presents the net proceeds from the i-unit issuance for the three month period March 31, 2013.

2013 Issuance Date	Number of i-units Issued	Price per i-unit	Net Proceeds to the Partnership [(1)]	General Partner Contribution [(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amount)			
March	10,350,000	$26.37	$272.9	$5.8	$278.7

(1) Net of underwriters' fees, discounts, commissions, and estimated costs paid by Enbridge Management.

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

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our Credit Facilities. 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 credit agreement with Bank of America, as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility, and our $1.1 billion credit agreement with JPMorgan Chase Bank as administrative agent, and a syndicate of 12 lenders, which we refer to as the 364-Day Credit Facility. We access our commercial paper program primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities.

Credit Facilities

In September 2011, we entered into the Credit Facility. The agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2.0 billion, a letter of credit subfacility and a swing line subfacility. Effective September 26, 2012, we extended the maturity date to September 26, 2017 and amended it to adjust the base interest rates.

On July 6, 2012, we entered into the 364-Day Credit Facility. The agreement is a committed senior unsecured revolving credit facility pursuant to which the lenders have committed to lend us up to $675.0 million: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion; and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods. On February 8, 2013, we amended the 364-Day Facility to reflect an increase in the lending commitments to $1.1 billion. The amended credit agreement has terms consistent with the original 364-Day Credit Facility.

We refer to the Credit Facility and the 364-Day Credit Facility as our Credit Facilities. Our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at March 31, 2013, we could borrow $1.6 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$3,100.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,300.0
Letters of credit outstanding	189.1
Total amount we could borrow at March 31, 2013	$1,610.9

Individual London Interbank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the three month periods ended March 31, 2013 and 2012, we have not renewed any LIBOR rate borrowings or base rate borrowings, on a non-cash basis.

Our Credit Facility previously was amended, and our 364-Day Credit Facility is written, to exclude up to $650 million of the costs associated with the remediation of the area affected by the Line 6B crude oil release from the EBITDA component of the consolidated leverage ratio covenant in each of our Credit Facilities. As previously disclosed, we received an order on March 14, 2013 from the Environmental Protection Agency, or the EPA, requiring additional work related to the Line 6B crude oil release, which we estimate to be approximately $175.0 million. Since this additional amount is not excluded from the computation of EBITDA component of the consolidated leverage ratio covenant, and we recorded that amount as an expense in the first three months of 2013, we anticipated that we would not be in compliance with the consolidated leverage ratio covenant at March 31, 2013. On March 29, 2013, we obtained waivers from all lenders under each of our Credit Facilities waiving our compliance with the consolidated leverage ratio determined as of March 31, 2013. The actual ratio was above the maximum ratio allowed by the Credit Facilities. Our ability to comply with that covenant in the future will depend on our ability to issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. A failure to comply with that covenant, without further waiver or amendment under our Credit Facilities, could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with this covenant under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants.

Commercial Paper

At March 31, 2013, we had $1,300.0 million of commercial paper outstanding at a weighted average interest rate of 0.40%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $140.0 million during the three month period ended March 31, 2013, which includes gross borrowings of $4,238.9 million and gross repayments of $4,098.9 million. Our policy is that the commercial paper we can issue is limited by the amounts available under our Credit Facilities up to an aggregate principal amount of $1.5 billion.

Joint Funding Arrangements

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

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010.

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Pipeline we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At March 31, 2013, we had approximately $324.0 million outstanding under the A1 Term Note.

The OLP paid a distribution of $13.8 million to our General Partner and its affiliate during the three month period ended March 31, 2013 for their noncontrolling interest in the Series AC, representing limited partner ownership interests of the OLP that are specifically related to the assets, liabilities and operations of the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $12.9 million and $13.0 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month periods ended March 31, 2013 and 2012, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its limited partnership agreement to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. All assets, liabilities and operations related to the Eastern Access Projects are owned 60% by our General Partner and 40% by the Partnership as per the funding agreement we refer to as the Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points.

We allocated earnings derived from operating the Eastern Access Project in the amount of $2.7 million to our General Partner for its 60% share of the earnings of the Eastern Access Project for the three month period ended March 31, 2013. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Eastern Access Project in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Joint Funding Arrangement for Mainline Expansion Projects

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. The projects will be jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement which parallels the Eastern Access Joint Funding Agreement. We also have an option, exercisable prior to June 30, 2013, for the Partnership to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points.

Our General Partner has made equity contributions totaling $22.8 million to the OLP during the three month period ended March 31, 2013 to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Cash Requirements

Capital Spending

We expect to make additional expenditures during the remainder of the year for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2013, we expect to spend approximately $3.1 billion on system enhancements and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. We expect to receive funding of approximately $930 million from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects. We made capital expenditures of $448.0 million for the three month period ending March 31, 2013, including $18.1 million on core maintenance activities, $36.8 million in contributions to the Texas Express Pipeline and $22.8 million of expenditures that were financed by contributions from our General Partner via the joint funding arrangement. At March 31, 2013, we had approximately $734.9 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2013.

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under our Credit Facilities and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful life. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as core maintenance expenditures. Enhancement 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 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. Given sustained natural gas prices and weaker NGL prices for ethane and propane, our Natural Gas business will face challenges over our near-term planning horizon. As such, with our focus to exercise prudent financial management and optimize our capital, we plan to reduce capital investment into the natural gas business in the near term. We will continue to consider opportunities in the Natural Gas business that will elevate our long-term, fee-based profile or strengthen our existing assets.

The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance for the year ending December 31, 2013. Although we anticipate making these expenditures in 2013, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. For the full year ending December 31, 2013, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Eastern Access Projects	$1,220
U.S. Mainline Expansions	330
North Dakota Expansion Program	185
Line 6B 75-mile Replacement Program	95
Liquids Integrity Program	275
Ajax Cryogenic Processing Plant	55
System Enhancements	610
Core Maintenance Activities	130
Joint Venture Projects	
Texas Express Pipeline	185
	3,085
Less: Joint Funding by General Partner	930
	$2,155

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.

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. The capital spending components of our programs have increased over time as our pipeline systems age.

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. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that core maintenance capital will continue to increase due to the growth of our pipeline systems and the aging of portions of these systems. Core maintenance expenditures are expected to be funded by operating cash flows.

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

Environmental

Lakehead Line 6B Crude Oil Release

During the three month period ended March 31, 2013, our cash flows were impacted by the approximate $7.8 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil releases that occurred in 2010 on Line 6B of our Lakehead system. We expect to pay the majority of the total estimated cost of $175.0 million, related to the Order received from the EPA during 2013.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers believe their payment is predicated on the outcome of our recovery with that insurer. While we believe that our claims for the remaining $145.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

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 March 31, 2013 for each of the indicated calendar years:

	Notional	2013	2014	2015	2016	2017	Total [4]
			(in millions)				
Swaps							
Natural gas [1]	56,558,870	$ 4.9	$(0.4)	$—	$—	$—	$ 4.5
NGL [2]	3,983,050	4.3	1.3	1.2	—	—	6.8
Crude Oil [2]	3,593,345	(6.3)	2.0	7.2	0.6	—	3.5
Options							
Natural gas—puts purchased [1]	1,237,500	0.5	—	—	—	—	0.5
NGL—puts purchased [2]	631,250	2.7	2.4	—	—	—	5.1
NGL—call written [2]	136,500	—	(0.4)	—	—	—	(0.4)
Forward contracts							
Natural gas [1]	69,483,662	0.1	0.1	0.3	0.1	—	0.6
NGL [2]	13,770,435	3.2	(0.2)	—	—	—	3.0
Crude Oil [2]	1,488,990	1.8	—	—	—	—	1.8
Power [3]	90,953	(0.3)	(0.7)	—	—	—	(1.0)
Totals		$10.9	$ 4.1	$ 8.7	$ 0.7	$—	$24.4

(1) Notional amounts for natural gas are recorded in MMBtu.
(2) Notional amounts for NGLs and crude oil are recorded in Barrels, or Bbl.
(3) Notional amounts for power are recorded in Megawatt hours, or MWh.
(4) Fair values exclude credit adjustments of approximately $0.5 million of losses at March 31, 2013.

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 March 31, 2013 for each of the indicated calendar years:

	Notional Amount	2013	2014	2015	2016	2017	Thereafter	Total
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$2,125.0	$ (18.0)	$ (8.9)	$(7.2)	$ (5.6)	$(2.7)	$(0.1)	$ (42.5)
Fixed to Floating	$ 125.0	1.0	—	—	—	—	—	1.0
Pre-issuance hedges	$2,350.0	(227.1)	(36.7)	—	15.7	—	—	(248.1)
		$(244.1)	$(45.6)	$(7.2)	$10.1	$(2.7)	$(0.1)	$(289.6)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $8.8 million of gains at March 31, 2013.

Cash Flow Analysis

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

	For the three month period ended March 31, 2013	2012	Variance 2013 vs. 2012 Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 205.9	$ 257.5	$ (51.6)
Investing activities	(437.9)	(272.0)	(165.9)
Financing activities	245.6	(131.1)	376.7
Net increase (decrease) in cash and cash equivalents	13.6	(145.6)	159.2
Cash and cash equivalents at beginning of year	227.9	422.9	(195.0)
Cash and cash equivalents at end of period	$ 241.5	$ 277.3	$ (35.8)

Operating Activities

Net cash provided by our operating activities decreased $51.6 million for the three month period ended March 31, 2013, compared to the same period in 2012, is primarily due to:

- Decrease in net income of $179.7 million offset by non-cash items which primarily consisted of:
  - Increase of $174.7 million in environmental costs primarily attributed to the EPA Order;
  - Increase in AEDC and AIDC of $10.6 million; and
  - Offset by increased depreciation of $8.6 due to increased additions to property, plant and equipment.
- Decrease in our working capital accounts of $43.9 million as compared to the same period in 2012 were primarily affected by $43.4 million less of environmental cost paid associated with the Line 6B crude oil releases for the three month period ended March 31, 2013 as compared with the same period in 2012.

Investing Activities

Net cash used in our investing activities during the three month period ended March 31, 2013 increased by $165.9 million, compared to the same period of 2012, primarily due to additions to property, plant and equipment in 2013 related to various enhancement projects. We also made additional cash contributions to our joint venture project, Texas Express Pipeline, of $9.2 million more during the three months ended March 31, 2013 as compared to the same period in 2012.

Financing Activities

Net cash provided by our financing activities increased $376.7 million for the three month period ended March 31, 2013, compared to the same period in 2012, primarily due to the following:

- Increase in proceeds from i-unit issuance of $278.7 million;
- Increase in net borrowings on our commercial paper of $89.9 million;
- Increase of $22.8 million in capital contributions from our General Partner and its affiliates for its ownership interest in Mainline Expansion Projects; and
- Offsetting the increases above was $16.7 million additional cash used for distributions to our partners in 2013.

SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2013, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2013. The distribution will be paid to unitholders of record as of May 8, 2013, of our available cash of $206.2 million at March 31, 2013, or $0.5435 per limited partner unit. Of this distribution, $177.2 million will be paid in cash, $28.4 million will be distributed in i-units to our i-unitholder, Enbridge Management, and $0.6 million will be retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series AC Interests

On April 30, 2013, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series AC interests, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $14.9 million to the noncontrolling interest in the Series AC, while $7.5 million will be paid to us.

REGULATORY MATTERS

FERC Transportation Tariffs

Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilizes the System Expansion Project II, or SEP II, and the Facility Surcharge Mechanism, or FSM, which are components of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing increased the average transportation rate for crude oil movements from the Canadian border to the Chicago, Illinois area by an average of approximately $0.26 per barrel, to an average of approximately $1.93 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on 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.

Effective April 1, 2013, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. These expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.55 per barrel, to an average of approximately $2.06 per barrel.

Effective April 1, 2012, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2012 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. Also included was recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order.

The tariff rate is applicable to each barrel of crude oil that is delivered on our system on or after the effective date of the tariff. This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.22 per barrel.

Effective July 1, 2012, we filed FERC tariffs for our Lakehead, North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.086011, which was issued by FERC on May 15, 2012, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with FERC filing 18 C.F.R.3423 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by approximately $0.07 per barrel.

The April 1, 2012 and July 1, 2012 tariff changes decreased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.15 per barrel, to an average of approximately $1.67 per barrel.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2012, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins, which is the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases. 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. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and 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 forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at March 31, 2013.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate [1]	Fair Value [2] at March 31, 2013	Fair Value [2] at December 31, 2012
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 600	4.15%	$ (16.7)	$ (22.6)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$ 125	4.35%	$ (0.9)	$ (2.2)
Interest Rate Swaps—Pay Float	Non-qualifying	$ 125	4.75%	$ 1.0	$ 2.4
Contracts maturing in 2014					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 200	0.56%	$ (0.5)	$ (0.6)
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.7)	$ (6.7)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (16.0)	$ (16.0)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ (1.7)	$ (1.8)
Contracts settling prior to maturity					
2012—Pre-issuance Hedges	Cash Flow Hedge	$ —	—	$ —	$(154.0)
2013—Pre-issuance Hedges	Cash Flow Hedge	$1,100	4.51%	$(227.1)	$ (84.4)
2014—Pre-issuance Hedges	Cash Flow Hedge	$ 750	3.15%	$ (36.7)	$ (45.3)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 15.7	$ 8.4

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

(2) The fair value is determined from quoted market prices at March 31, 2013 and December 31, 2012, 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 adjustments of approximately $8.8 million of gains at March 31, 2013 and $13.7 million of gains at December 31, 2012.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2013 and December 31, 2012.

	At March 31, 2013						At December 31, 2012	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	1,932,100	$ 3.99	$ 3.54	$ 0.9	$(0.1)	$ 0.2	$(0.3)
	NGL	603,000	$ 53.94	$50.61	$ 2.0	$—	$ 1.4	$—
	Crude Oil	—	$ —	$ —	$—	$—	$ 0.2	$—
Receive fixed/pay variable	Natural Gas	3,634,500	$ 4.92	$ 4.05	$ 3.6	$(0.4)	$ 7.8	$—
	NGL	2,318,125	$ 53.01	$52.03	$ 8.0	$(5.7)	$ 9.3	$(9.9)
	Crude Oil	1,320,225	$ 92.00	$96.79	$ 3.1	$(9.4)	$ 6.3	$(8.8)
Receive variable/pay variable	Natural Gas	40,361,000	$ 4.05	$ 4.03	$ 1.0	$(0.1)	$ 1.2	$(0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	830,000	$ 40.87	$36.72	$ 3.9	$(0.5)	$ 0.6	$(0.8)
	Crude Oil	126,000	$ 97.33	$96.14	$ 0.3	$(0.1)	$ 0.4	$(0.4)
Receive fixed/pay variable	NGL	1,593,115	$ 39.04	$40.87	$ 0.5	$(3.4)	$ 2.6	$(2.2)
	Crude Oil	195,000	$ 95.72	$97.42	$ 0.1	$(0.5)	$ 0.2	$(1.0)
Receive variable/pay variable	Natural Gas	38,822,722	$ 4.06	$ 4.05	$ 0.6	$(0.5)	$ 0.9	$—
	NGL	7,164,820	$ 40.23	$39.85	$ 5.4	$(2.7)	$ 5.2	$(2.3)
	Crude Oil	1,167,990	$100.18	$98.52	$ 4.4	$(2.4)	$ 6.4	$(3.0)
Pay fixed	Power (4)	32,345	$ 34.42	$42.82	$—	$(0.3)	$—	$(0.5)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 4.31	$ 5.22	$—	$—	$—	$—
	NGL	60,000	$ 82.95	$85.26	$—	$(0.1)	$—	$—
Receive fixed/pay variable	Natural Gas	2,496,900	$ 4.01	$ 4.20	$—	$(0.5)	$ 0.2	$—
	NGL	892,425	$ 63.63	$62.10	$ 3.0	$(1.6)	$ 0.9	$(2.7)
	Crude Oil	1,361,955	$ 94.22	$92.79	$ 5.1	$(3.1)	$ 5.4	$(2.7)
Receive variable/pay variable	Natural Gas	8,112,500	$ 4.31	$ 4.30	$ 0.2	$(0.1)	$ 0.1	$(0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	21,409,275	$ 4.33	$ 4.32	$ 0.5	$(0.4)	$ 0.5	$—
	NGL	4,182,500	$ 18.23	$18.27	$—	$(0.2)	$—	$—
Pay fixed	Power (4)	58,608	$ 34.48	$46.58	$—	$(0.7)	$—	$(0.8)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$77.40	$ 1.2	$—	$ 0.7	$(0.2)
	Crude Oil	865,415	$ 97.72	$89.33	$ 7.3	$(0.1)	$ 6.8	$(0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,468,425	$ 4.34	$ 4.30	$ 0.4	$(0.1)	$ 0.4	$—
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$86.97	$ 0.6	$—	$ 0.5	$—
Physical Contracts								
Receive variable/pay variable	Natural Gas	783,240	$ 4.50	$ 4.38	$ 0.1	$—	$ 0.1	$—

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2013 and December 31, 2012, 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 adjustments of approximately $0.5 million of losses at March 31, 2013 and $0.4 million of losses at December 31, 2012.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at March 31, 2013 and December 31, 2012.

	At March 31, 2013						At December 31, 2012	
					Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Strike Price (2)	Market Price (2)	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2013								
Puts (purchased)	Natural Gas	1,237,500	$ 4.18	$ 3.99	$ 0.5	$—	$ 1.4	$—
	NGL	367,000	$31.90	$28.34	$ 2.7	$—	$ 3.7	$—
Portion of option contracts maturing in 2014								
Puts (purchased)	NGL	264,250	$52.46	$50.87	$ 2.4	$—	$ 1.3	$—
Calls (written)	NGL	136,500	$54.17	$40.34	$—	$(0.4)	$—	$—

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2013 and December 31, 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

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

	March 31, 2013	December 31, 2012
	(in millions)	
Counterparty Credit Quality*		
AA	$(105.5)	$(116.5)
A	(155.8)	(147.7)
Lower than A	4.4	(16.7)
	$(256.9)	$(280.9)

* 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, or the Exchange Act, within the time periods specified in the rules and forms of the Securities and Exchange Commission, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 2013. 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 month period ended March 31, 2013.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 9—*Commitments and Contingencies*," which is incorporated herein by reference.

Item 1A. Risk Factors

The risk factor presented below updates and should be considered in addition the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

Ability to Comply with Financial Covenants of the Credit Facilities

Each of our Credit Facilities requires that we comply with, among other covenants, a quarterly determined consolidated leverage ratio covenant, which limits our Consolidated Funded Debt to a prescribed multiple of our Pro Forma EBITDA (as each term is defined in the Credit Facilities). Our Credit Facility previously has been amended, and our 364-Day Credit Facility is written, to exclude up to $650 million of the costs associated with the remediation of the area affected by the Line 6B crude oil release from the EBITDA component of the consolidated leverage ratio covenant. As previously disclosed, we received an order on March 14, 2013 from the EPA requiring additional work related to the Line 6B crude oil release, which we estimate to be $175.0 million. Since this amount is not excluded from the calculation of EBITDA in the consolidated leverage ratio covenant, and we recorded that amount as an expense in the first three months of 2013, we anticipated that we would not be in compliance with the consolidated leverage ratio covenant at March 31, 2013. On March 29, 2013, we obtained waivers from all lenders under each of our Credit Facilities waiving our compliance with the consolidated leverage ratio determined as of March 31, 2013. Our ability to comply with that covenant in the future will depend on our ability to issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. A failure to comply with that covenant, without further waiver or amendment under our Credit Facilities, could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with this covenant under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants.

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: May 1, 2013

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

Date: May 1, 2013

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

Index of Exhibits

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

Exhibit Number	Description
10.1	Credit Agreement dated as of July 6, 2012, by and among the Partnership, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on February 14, 2013).
10.2	Amendment No. 1 to Credit Agreement, dated as of February 8, 2013, by and among the Partnership, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on February 14, 2013).
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(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2013

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, Stephen J. Neyland, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 1, 2013

By: /s/ Stephen J. Neyland

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

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 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 March 31, 2013 (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: May 1, 2013

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 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 March 31, 2013 (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: May 1, 2013

By: /s/ Stephen J. Neyland

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