ENBRIDGE ENERGY PARTNERS LP
Form 10-Q
July 31, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 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	**(I.R.S. Employer Identification No.)**

Incorporation or Organization)

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 x 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 x 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	x	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 x

The registrant had 254,208,428 Class A common units outstanding as of July 30, 2013.

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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 Line 6B and any additional fines and penalties assessed in connection with the crude oil release on that line; (6) changes in or challenges to our tariff rates; 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).

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended June 30, 2013	2012	For the six month period ended June 30, 2013	2012
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 10)	$ 1,672.7	$ 1,551.1	$ 3,365.7	$ 3,370.6
Operating expenses:				
Cost of natural gas (Notes 4 and 10)	1,115.5	975.2	2,306.9	2,272.1
Environmental costs, net of recoveries (Note 9)	5.2	22.7	183.7	25.9
Operating and administrative	218.0	206.2	412.9	403.1
Power (Note 10)	29.2	37.4	62.8	78.6
Depreciation and amortization (Note 5)	95.8	86.1	188.0	169.7
	1,463.7	1,327.6	3,154.3	2,949.4
Operating income	209.0	223.5	211.4	421.2
Interest expense (Notes 6 and 10)	79.5	81.8	155.9	165.4
Other income (expense)	0.3	(0.3)	0.6	(0.3)
Allowance for equity used during construction (Note 13)	8.1		15.9	
Income before income tax expense	137.9	141.4	72.0	255.5
Income tax expense (Note 11)	14.2	1.7	16.0	3.8
Net income	123.7	139.7	56.0	251.7
Less: Net income attributable to Noncontrolling interest (Note 8)	18.4	15.1	34.0	28.1
Series 1 preferred unit distributions (Note 7)	13.1		13.1	
Accretion of discount on Series 1 preferred units (Note 7)	2.3		2.3	
Net income attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 89.9	$ 124.6	$ 6.6	$ 223.6
Net income (loss) allocable to limited partner interests	$ 56.7	$ 93.7	$ (56.2)	$ 165.4
Net income (loss) per limited partner unit (basic) (Note 2)	$ 0.18	$ 0.33	$ (0.18)	$ 0.58
Weighted average limited partner units outstanding (basic)	314.8	285.4	311.0	285.1
Net income (loss) per limited partner unit (diluted) (Note 2)	$ 0.18	$ 0.33	$ (0.18)	$ 0.58
Weighted average limited partner units outstanding (diluted)	314.8	285.4	311.0	285.1

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(unaudited; in millions)			
Net income	$ 123.7	$ 139.7	$ 56.0	$ 251.7
Other comprehensive income (loss), net of tax expense of $0.1 million, $0.4 million, $0.1 million and $0.3 million, respectively (Note 10)	162.0	(33.3)	191.7	2.1
Comprehensive income	285.7	106.4	247.7	253.8
Less: Comprehensive income attributable to Noncontrolling interest (Note 8)	18.4	15.1	34.0	28.1
Series 1 preferred unit distributions (Note 7)	13.1		13.1	
Accretion of discount on Series 1 preferred units (Note 7)	2.3		2.3	
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 251.9	$ 91.3	$ 198.3	$ 225.7

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the six month period ended June 30, 2013	2012
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 56.0	$ 251.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	188.0	169.7
Derivative fair value net gains (Note 10)	(22.3)	(44.9)
Inventory market price adjustments (Note 4)	2.5	9.6
Environmental costs, net of recoveries (Note 9)	179.7	17.5
Deferred income taxes(Note 11)	13.2	
State income taxes	7.4	
Allowance for equity used during construction	(15.9)	
Other (Note 14)	7.3	7.2
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	60.1	(10.4)
Due from General Partner and affiliates	4.5	(11.9)
Accrued receivables	276.3	160.4
Inventory (Note 4)	(95.1)	(3.4)
Current and long-term other assets (Note 10)	(19.1)	(3.7)
Due to General Partner and affiliates	18.4	6.5
Accounts payable and other (Notes 3 and 10)	(40.3)	31.1
Environmental liabilities (Note 9)	(32.7)	(27.2)
Accrued purchases	(95.3)	(180.8)
Interest payable	4.1	
Property and other taxes payable	(14.0)	(14.9)
Settlement of interest rate derivatives	(5.3)	
Net cash provided by operating activities	477.5	356.5
Cash used in investing activities:		
Additions to property, plant and equipment (Note 5)	(867.1)	(651.7)
Changes in construction payables	7.4	27.7
Changes in restricted cash (Note 8)	(3.4)	
Investment in joint venture	(126.7)	(37.9)
Other	(4.0)	4.6
Net cash used in investing activities	(993.8)	(657.3)
Cash provided by financing activities:		
Net proceeds from Series 1 preferred unit issuance (Note 7)	1,200.0	
Net proceeds from i-unit issuances (Note 7)	278.7	
Distributions to partners (Note 7)	(353.3)	(318.8)
Repayments to General Partner (Note 8)	(6.0)	(6.0)
Repayments of long-term debt (Note 6)	(200.0)	
Net commercial paper borrowings (repayments)(Note 6)	(724.7)	395.0
Contribution from noncontrolling interest (Note 8)	149.7	31.1
Distributions to noncontrolling interest (Note 8)	(28.7)	(32.6)
Net cash provided by financing activities	315.7	68.7

Net decrease in cash and cash equivalents	(200.6)	(232.1)
Cash and cash equivalents at beginning of year	227.9	422.9
Cash and cash equivalents at end of period	$ 27.3	$ 190.8

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2013	December 31, 2012
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 3)	$ 27.3	$ 227.9
Restricted cash (Note 8)	3.4	
Receivables, trade and other, net of allowance for doubtful accounts of $1.7 million in 2013 and $1.9 million in 2012 (Note 9)	124.3	142.4
Due from General Partner and affiliates	23.2	27.2
Accrued receivables	293.4	569.7
Inventory (Note 4)	160.1	72.7
Other current assets (Note 10)	77.4	48.0
	709.1	1,087.9
Property, plant and equipment, net (Note 5)	11,633.6	10,937.6
Goodwill	246.7	246.7
Intangibles, net	256.6	257.2
Other assets, net (Note 10)	455.0	267.4
	$ 13,301.0	$ 12,796.8
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Due to General Partner and affiliates	$ 76.1	$ 43.5
Accounts payable and other (Notes 3, 10 and 13)	482.3	646.0
Environmental liabilities (Note 9)	280.2	108.0
Accrued purchases	388.8	484.1
Interest payable	67.8	69.0
Property and other taxes payable (Note 11)	57.4	71.4
Note payable to General Partner (Note 8)	12.0	12.0
Current maturities of long-term debt (Note 6)		200.0
	1,364.6	1,634.0
Long-term debt (Note 6)	4,777.1	5,501.7
Loans from General Partner and affiliate (Note 8)	312.0	318.0
Deferred income tax liability (Note 11)	16.3	3.0
Other long-term liabilities (Notes 9 and 10)	102.1	92.2
Total liabilities	6,572.1	7,548.9
Commitments and contingencies (Note 9)		
Partners capital: (Notes 7 and 8)		
Series 1 preferred units (48,000,000 at June 30, 2013)	1,154.6	
Class A common units (254,208,428 at June 30, 2013 and December 31, 2012)	3,307.9	3,590.2
Class B common units (7,825,500 at June 30, 2013 and December 31, 2012)	75.3	83.9
i-units (53,246,925 and 41,198,424 at June 30, 2013 and December 31, 2012, respectively)	1,070.1	801.8
General Partner	301.3	299.0
Accumulated other comprehensive income (loss) (Note 10)	(128.8)	(320.5)

Total Enbridge Energy Partners, L.P. partners capital	5,780.4	4,454.4
Noncontrolling interest (Note 8)	948.5	793.5
Total partners capital	6,728.9	5,247.9
	$ 13,301.0	$ 12,796.8

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

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ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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 June 30, 2013, our results of operations for the three and six month periods ended June 30, 2013 and 2012 and our cash flows for the six month periods ended June 30, 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 and six month periods ended June 30, 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 $2.8 million and $7.1 million for oil measurement gains from Oil measurement adjustments to Operating and administrative in our consolidated statement of income for the three and six month periods ended June 30, 2012, respectively.

2. NET INCOME PER LIMITED PARTNER UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, our General Partner, or Enbridge Energy Company, Inc., and our limited partners using first preferred unit distributions and then the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, after noncontrolling interest and preferred unit distributions, including any incentive distribution rights 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, after Preferred Unit allocations, 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 %

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

	For the three month period ended June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(in millions, except per unit amounts)			
Net income	$ 123.7	$ 139.7	$ 56.0	$ 251.7
Less Net income attributable to:				
Noncontrolling interest	(18.4)	(15.1)	(34.0)	(28.1)
Series 1 preferred unit distributions	(13.1)		(13.1)	
Accretion of discount on Series 1 preferred units	(2.3)		(2.3)	
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	89.9	124.6	6.6	223.6
Less distributions paid:				
Incentive distributions to our General Partner	(32.0)	(28.9)	(63.9)	(54.8)
Distributed earnings allocated to our General Partner	(3.5)	(3.3)	(7.0)	(6.3)
Total distributed earnings to our General Partner	(35.5)	(32.2)	(70.9)	(61.1)
Total distributed earnings to our limited partners	(171.3)	(155.3)	(342.1)	(307.1)
Total distributed earnings	(206.8)	(187.5)	(413.0)	(368.2)
Overdistributed earnings	$ (116.9)	$ (62.9)	$ (406.4)	$ (144.6)
Weighted average limited partner units outstanding	314.8	285.4	311.0	285.1
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit [(1)]	$ 0.54	$ 0.54	$ 1.10	$ 1.08
Overdistributed earnings per limited partner unit [(2)]	(0.36)	(0.21)	(1.28)	(0.50)
Net income (loss) per limited partner unit (basic and diluted) [(3)]	$ 0.18	$ 0.33	$ (0.18)	$ 0.58

(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) For the three and six month periods ended June 30, 2013, 43,201,310 anti-dilutive Preferred Units were excluded from the if-converted method of calculating diluted earnings per unit.

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 $21.0 million at June 30, 2013 and $22.8 million at December 31, 2012 are included in Accounts payable and other on our consolidated statements of financial position.

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4. INVENTORY

Our inventory is comprised of the following:

	June 30, 2013	December 31, 2012
	(in millions)	
Materials and supplies	$ 2.1	$ 1.9
Crude oil inventory	31.9	12.7
Natural gas and NGL inventory	126.1	58.1
	$ 160.1	$ 72.7

The Cost of natural gas on our consolidated statements of income includes charges totaling $1.7 million and $7.2 million, and $2.5 million and $9.6 million for the three and six month periods ended June 30, 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:

	June 30, 2013	December 31, 2012
	(in millions)	
Land	$ 40.3	$ 40.4
Rights-of-way	651.0	604.5
Pipelines	7,392.9	6,662.3
Pumping equipment, buildings and tanks	2,057.6	1,646.4
Compressors, meters and other operating equipment	1,919.0	1,755.7
Vehicles, office furniture and equipment	317.6	222.7
Processing and treating plants	505.0	489.8
Construction in progress	1,277.4	1,867.2
Total property, plant and equipment	14,160.8	13,289.0
Accumulated depreciation	(2,527.2)	(2,351.4)
Property, plant and equipment, net	$ 11,633.6	$ 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.

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.

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On July 3, 2013, we amended our 364-Day Credit Facility, to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on July 24, 2013, we further amended the 364-Day Credit Facility, adding a new lender and increasing our aggregate commitments under the facility by another $50.0 million. After these amendments, our 364-day Credit Facility now provides aggregate lending commitments of $1.2 billion, as discussed in Note 15. *Subsequent Events.*

Our Credit Facility has been amended, and our 364-Day Credit Facility, which is discussed above, 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 Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of those facilities, which we refer to, collectively, as our Credit Facilities. At June 30, 2013, we were in compliance with the terms of our financial covenants under the Credit Facilities.

As of June 30, 2013, 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 June 30, 2013, we could borrow approximately $2.6 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	435.0
Letters of credit outstanding	74.0
Total amount we could borrow at June 30, 2013	$ 2,591.0

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 and six month periods ended June 30, 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 and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At June 30, 2013, we had $0.4 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.35%, 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.

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Senior Notes

During the second quarter of 2013, $200.0 million of our notes reached full maturity, which we repaid in full on June 3, 2013.

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 June 30, 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.

	June 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$ 435.0	$ 435.0	$ 1,160.0	$ 1,160.0
4.750% Senior Notes due 2013			200.0	203.9
5.350% Senior Notes due 2014	200.0	214.3	200.0	215.6
5.875% Senior Notes due 2016	299.9	336.9	299.9	345.1
7.000% Senior Notes due 2018	99.9	119.7	99.9	124.6
6.500% Senior Notes due 2018	399.0	466.8	398.8	484.1
9.875% Senior Notes due 2019	500.0	677.2	500.0	710.5
5.200% Senior Notes due 2020	499.9	550.2	499.9	575.4
4.200% Senior Notes due 2021	599.0	611.8	598.9	644.2
7.125% Senior Notes due 2028	99.8	126.8	99.8	137.5
5.950% Senior Notes due 2033	199.8	223.0	199.8	244.2
6.300% Senior Notes due 2034	99.8	115.3	99.8	126.5
7.500% Senior Notes due 2038	399.0	522.5	399.0	573.8
5.500% Senior Notes due 2040	546.3	549.5	546.3	605.5
8.050% Junior subordinated notes due 2067	399.7	446.3	399.6	453.6
Total	$ 4,777.1	$ 5,395.3	$ 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 six month period ended June 30, 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)			

April 30, 2013	May 8, 2013	May 15, 2013	$ 0.5435	$	206.2	$	28.4	$	0.6	$	177.2
January 30, 2013	February 7, 2013	February 14, 2013	$ 0.5435	$	198.9	$	22.4	$	0.4	$	176.1

(1) We issued 1,698,501 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.

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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 and six month periods ended June 30, 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 June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(in millions)			
Series 1 Preferred interests				
Beginning balance	$	$	$	$
Proceeds from issuance of preferred units	1,200.0		1,200.0	
Net income	13.1		13.1	
Accretion of discount on preferred units	2.3		2.3	
Distribution payable	(13.1)		(13.1)	
Beneficial conversion feature of preferred units	(47.7)		(47.7)	
Ending balance	$ 1,154.6	$	$ 1,154.6	$
General and limited partner interests				
Beginning balance	$ 4,794.2	$ 4,422.7	$ 4,774.9	$ 4,483.1
Proceeds from issuance of partnership interests, net of costs		2.0	278.7	2.0
Net income	89.9	124.6	6.6	223.6
Distributions	(177.2)	(159.4)	(353.3)	(318.8)
Beneficial conversion feature of preferred units	47.7		47.7	
Ending balance	$ 4,754.6	$ 4,389.9	$ 4,754.6	$ 4,389.9
Accumulated other comprehensive income (loss)				
Beginning balance	$ (290.8)	$ (281.1)	$ (320.5)	$ (316.5)
Net realized income on changes in fair value of derivative financial instruments reclassified to earnings	10.5	8.5	16.5	22.3
Unrealized net income (loss) on derivative financial instruments	151.5	(41.8)	175.2	(20.2)
Ending balance	$ (128.8)	$ (314.4)	$ (128.8)	$ (314.4)
Noncontrolling interest				
Beginning balance	$ 818.1	$ 442.7	$ 793.5	$ 445.5
Capital contributions	126.9	31.1	149.7	31.1
Comprehensive income:				
Net income	18.4	15.1	34.0	28.1
Distributions to noncontrolling interest	(14.9)	(16.8)	(28.7)	(32.6)
Ending balance	$ 948.5	$ 472.1	$ 948.5	$ 472.1
Total partners capital at end of period	$ 6,728.9	$ 4,547.6	$ 6,728.9	$ 4,547.6

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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 a number of our i-units equal to the number of Listed Shares sold in the offering. We used 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 six month period ended June 30, 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.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, or Preferred Units, representing limited partner interests in the Partnership for aggregate proceeds of approximately $1.2 billion. . The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, which is subject to reset every five years. In addition, quarterly cash distributions will not be payable on the Preferred Units during the first full eight quarters ending June 30, 2015, and instead accrue and accumulate the payment deferral, which is referred to as the Payment Deferral, and will be payable upon the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) the Partnership uses the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders and General Partner s capital and a decrease in Preferred Unitholders capital to reflect the fair value of the Preferred Units at issuance on the Partnership s consolidated statement of changes in partners capital for the six month period ended June 30, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders capital. The impact of the beneficial conversion feature is also included in earnings per unit for the three and six month periods ended June 30, 2013 and 2012.

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Proceeds from the Preferred Unit issuance were used by the Partnership to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

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, which we refer to as the Series AC. 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 June 30, 2013 and 2012 are as follows:

	A1 Term Note June 30,	
	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 $13.3 million and $26.2 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three and six month periods ended June 30, 2013, respectively. We also allocated $15.1 million and $28.1 million for the same three and six month periods ended June 30, 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.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the six month period ended June 30, 2013, representing the noncontrolling interest in the Series AC and to us, as the

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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 (in millions)	Total Series AC Distribution
January 30, 2013	February 14, 2013	$ 6.9	$ 13.8	$ 20.7
April 30, 2013	May 15, 2013	7.5	14.9	22.4
		$ 14.4	$ 28.7	$ 43.1

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. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points back to 40%. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $5.1 million and $7.8 million to our General Partner for its ownership of the EA interest for the three and six month periods ended June 30, 2013, respectively. 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 U.S. 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. From December 2012 through June 27, 2013, the projects were 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. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest by up to 15 percentage points back to 40%. All other operations are captured by the Lakehead interests. We received $12.0 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to the Mainline Expansion Projects.

Our General Partner has made equity contributions totaling $36.7 million and $59.5 million to the OLP for the three and six month periods ended June 30, 2013, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects. No such contributions were made during the six month period ended June 30, 2012.

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Sale of Accounts Receivable

On June 28, 2013, we and certain of our subsidiaries entered into a Receivables Purchase Agreement, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge, in exchange for cash. The Receivables Agreement and the transactions contemplated thereby were approved by a special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, current accounts receivables and accrued receivables, or the Receivables, of the Partnership s respective subsidiaries up to a monthly maximum of $350.0 million, of receivables from prior months that have not been collected, through December 2016. Following the sale and transfer of the Receivables to the Enbridge subsidiary, the Receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary.

Consideration for the Receivables sold is equivalent to the carrying value of the Receivables less a discount. The difference between the carrying value of the Receivables sold and the cash proceeds received is recognized in Operating and administrative expense in our consolidated statements of income. For the three and six month periods ended June 30, 2013, the loss stemming from the discount on the Receivables sold was not material. As of June 30, 2013, we sold and derecognized $213.0 million of our receivables to the Enbridge subsidiary of which $79.5 million were trade receivables and $133.5 million were accrued receivables for cash proceeds of $212.9 million.

As of June 30, 2013, we have $3.4 million included in Restricted cash on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary as of June 30, 2013. The Enbridge subsidiary retains the right to select a new collection agent at any time.

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 June 30, 2013 and December 31, 2012, we had $35.2 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 June 30, 2013, our total cost estimate for the Line 6B crude oil release is $1,035.0 million, which is an increase of $215.0 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, or the Environmental Protection Agency, 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. The EPA approved the Submerged Oil Recovery and Assessment workplan, or SORA, with modifications on May 8, 2013. We incorporated the modification and submitted an approved SORA on May 13, 2013. The Order states that the work must be completed by December 31, 2013.

The $175.0 million increase in the total cost estimate during the three month period ending March 31, 2013, was attributable to additional work required by the Order. The $40.0 million increase during the three month period ending June 30, 2013 was attributable to further refinement and definition of the additional dredging scope per the Order and associated environmental, permitting, waste removal and other related costs. The actual costs incurred may differ from the foregoing estimate as we complete the work plan with the EPA related to the Order 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 costs for the incident at June 30, 2013 exceeded 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 June 30, 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	$ 451
Environmental Consultants	197
Professional, regulatory and other	387
Total	$ 1,035

For the six month periods ended June 30, 2013 and 2012, we made payments of $23.6 million and $73.9 million, respectively, for costs associated with the Line 6B crude oil release. For the six month period ended June 30, 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 June 30, 2013 and December 31, 2012, we had a remaining estimated liability of $304.5 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 $0.7 million is the remaining liability at June 30, 2013, does not include an estimate for fines and penalties at June 30, 2013, which may be imposed by the EPA and PHMSA, in addition to other federal, state and local governmental agencies. At June 30, 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 June 30, 2013, we have exceeded the limits of coverage under this insurance policy. We recognized $42.0 million of insurance recoveries as reductions to Environmental costs, net of recoveries in our consolidated statement of income for the three and six month periods ended June 30, 2013. At June 30, 2013, we have $42.0 million recorded in Receivables, trade and other in our consolidate statement of financial position for insurance payments we will receive for a claim we filed in connection with the Line 6B crude oil release. 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. As of June 30, 2013, we have recorded total insurance recoveries of $547.0 million for the Line 6B crude oil release, out of the $650.0 million aggregate limit. We 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.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We will be receiving a partial recovery payment of $42.0 million from the other remaining insurers and have since amended our lawsuit, such that it now includes only one insurer. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit.

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.

Effective May 1, 2013, Enbridge renewed its comprehensive property and liability insurance programs, under which we are insured through April 30, 2014, with a current liability aggregate limit of $685.0 million, including sudden and accidental pollution liability. 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 45 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 an 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.

On July 25, 2013, the U.S. Department of Justice, or DOJ, and the EPA filed a complaint against us related to permit violations for the discharge of hydrotest water in 2010 related to the Alberta Clipper Pipeline and one of our affiliates. We have agreed to settle with the DOJ and EPA for $254.0 thousand related to the Alberta Clipper Pipeline portion of the permit violation.

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 2018 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 a mid-market pricing convention, or 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 in our consolidated statements of financial position, 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 our consolidated statements of income 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 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.

Natural Gas and NGL Options In our Natural Gas segment, we use options to hedge the forecasted commodity exposure of our NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. 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 volatility due to movements in the prices of NGLs and natural gas until the underlying long-term 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. 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.

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Derivative Positions

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

	June 30, 2013	December 31, 2012
	(in millions)	
Other current assets	$ 46.3	$ 28.3
Other assets, net	65.6	15.8
Accounts payable and other [(1)]	(136.4)	(256.7)
Other long-term liabilities	(54.4)	(68.3)
	$ (78.9)	$ (280.9)

(1) Includes $9.3 million of cash collateral at June 30, 2013.

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 $36.9 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 six month period ended June 30, 2013, unrealized commodity hedge gains of $1.5 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $117.5 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at June 30, 2013, will be reclassified from AOCI to earnings during the next 12 months.

During the current quarter it was determined that a portion of forecasted short term debt transactions are not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer meet the cash flow hedging requirements. These terminations resulted in realized gains of $5.3 million for the three and six month periods ended June 30, 2013.

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

	June 30, 2013	December 31, 2012
	(in millions)	
Counterparty Credit Quality [(1)]		
AAA	$ 0.2	$
AA	(41.5)	(116.5)
A [(2)]	(47.1)	(147.7)
Lower than A	9.5	(16.7)
	$ (78.9)	$ (280.9)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $9.3 million of cash collateral at June 30, 2013.

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As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also increased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of June 30, 2013 we are holding $9.3 million in cash collateral on our asset exposures, however, as of December 31, 2012, we were not holding any 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 June 30, 2013, we would have been required to provide additional letters of credit in the amount of $30.0 million.

At June 30, 2013 and December 31, 2012, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2013	December 31, 2012
	(in millions)	
United States financial institutions and investment banking entities	$ (86.7)	$ (204.5)
Non-United States financial institutions [(1)]	(8.5)	(84.6)
Other	16.3	8.2
	$ (78.9)	$ (280.9)

(1) Includes $9.3 million of cash collateral at June 30, 2013.

As of June 30, 2013, we are holding $9.3 million of cash collateral on our asset exposures, and we have provided letters of credit totaling $73.4 million and $231.2 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 2013 and December 31, 2012, respectively, under our ISDA® agreements.

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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	June 30, 2013	December 31, 2012	Financial Position Location	June 30, 2013	December 31, 2012
			(in millions)			
Derivatives designated as hedging instruments[1]						
Interest rate contracts	Other current assets	$	$	Accounts payable and other[2]	$ (119.1)	$ (246.9)
Interest rate contracts	Other assets, net	44.2	6.0	Other long-term liabilities	(56.1)	(68.3)
Commodity contracts	Other current assets	13.0	16.8	Accounts payable and other	(5.9)	(9.9)
Commodity contracts	Other assets, net	10.2	4.5	Other long-term liabilities	(0.7)	(5.5)
		67.4	27.3		(181.8)	(330.6)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets		2.4	Accounts payable and other		(2.2)
Commodity contracts	Other current assets	43.8	28.8	Accounts payable and other	(12.6)	(17.5)
Commodity contracts	Other assets, net	15.0	13.3	Other long-term liabilities	(1.4)	(2.4)
		58.8	44.5		(14.0)	(22.1)
Total derivative instruments		$ 126.2	$ 71.8		$ (195.8)	$ (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.
(2) Excludes $9.3 million of cash collateral at June 30, 2013.

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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 (in millions)	Amount of gain (loss) reclassified from AOCI to earnings	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]
For the three month period ended June 30, 2013					
Interest rate contracts	$ 148.7	Interest expense	$ (12.6)	Interest expense	$ 1.1
Commodity contracts	10.0	Cost of natural gas	2.1	Cost of natural gas	1.8
Total	$ 158.7		$ (10.5)		$ 2.9
For the three month period ended June 30, 2012					
Interest rate contracts	$ (110.5)	Interest expense	$ (7.1)	Interest expense	$ 0.2
Commodity contracts	74.0	Cost of natural gas	(1.4)	Cost of natural gas	7.0
Total	$ (36.5)		$ (8.5)		$ 7.2
For the six month period ended June 30, 2013					
Interest rate contracts	$ 177.6	Interest expense	$ (20.1)	Interest expense	$ 0.6
Commodity contracts	8.4	Cost of natural gas	3.6	Cost of natural gas	2.3
Total	$ 186.0		$ (16.5)		$ 2.9
For the six month period ended June 30, 2012					
Interest rate contracts	$ (66.9)	Interest expense	$ (14.3)	Interest expense	$ 0.3
Commodity contracts	70.1	Cost of natural gas	(8.0)	Cost of natural gas	5.1
Total	$ 3.2		$ (22.3)		$ 5.4

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges (in millions)
Balance at December 31, 2012	$ (320.5)
Other Comprehensive Income before reclassifications	175.3
Amounts reclassified from AOCI [1]	16.5
Tax benefit (expense)	(0.1)
Net Other Comprehensive Income	$ 191.7

Balance at June 30, 2013	$	(128.8)

(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

	For the three month period ended June 30, 2013	2012	For the six month period ended June 30, 2013	2012
	(in millions)			
Losses (gains) on cash flow hedges:				
Interest Rate Contracts (1)	$ 12.6	$ 7.1	$ 20.1	$ 14.3
Commodity Contracts (2)	(2.1)	1.4	(3.6)	8.0
Total Reclassifications from AOCI	$ 10.5	$ 8.5	$ 16.5	$ 22.3

(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(1)	For the three month period ended June 30, 2013 Amount of Gain or (Loss) Recognized in Earnings(2)	2012 (6)	For the six month period ended June 30, 2013 Amount of Gain or (Loss) Recognized in Earnings(2)	2012 (6)
		(in millions)			
Interest rate contracts	Interest expense(3)	$ (0.1)	$	$ (0.1)	$
Commodity contracts	Operating revenue(4)	4.2	22.7	2.7	14.8
Commodity contracts	Power	(0.1)	0.1	0.2	(0.2)
Commodity contracts	Cost of natural gas(5)	21.6	29.3	19.2	34.1
Total		$ 25.6	$ 52.1	$ 22.0	$ 48.7

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.
(2) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.
(3) Includes settlements gains of $0.2 million for the three month period ended June 30, 2012, as well as, $0.2 million and $0.2 million for the six month periods ended June 30, 2013 and June 30, 2012, respectively.
(4) Includes settlements gains of $0.9 million, $1.7 million, $1.7 million and $2.3 million for the three and six month periods ended June 30, 2013 and June 30, 2012, respectively.
(5) Includes settlements gains of $1.1 million, $5.6 million, $0.7 million and $6.7 million for the three and six month periods ended June 30, 2013 and June 30, 2012, respectively.
(6) The effects of derivative instruments on consolidated statements of income for the three and six month periods ended June 30, 2012 have been revised to include settlement gains on derivatives not designated as hedge instruments of $7.5 million and $9.2 million, respectively. The revisions to the disclosure had no impact on previously reported net income or earnings per unit.

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	June 30, 2013 Assets		Total	December 31, 2012 Assets	Liabilities	Total

		Liabilities (1)				
			(in millions)			
Fair value of derivatives gross presentation	$ 126.2	$ (205.1)	$ (78.9)	$ 71.8	$ (352.7)	$ (280.9)
Effects of netting agreements	(14.3)	14.3		(27.7)	27.7	
Fair value of derivatives net presentation	$ 111.9	$ (190.8)	$ (78.9)	$ 44.1	$ (325.0)	$ (280.9)

(1) Includes $9.3 million of cash collateral at June 30, 2013.

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 June 30, 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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
Description:					
Derivatives	$ 126.2	$ (14.3)	$ 111.9	$ (0.9)	$ 111.0
Total	$ 126.2	$ (14.3)	$ 111.9	$ (0.9)	$ 111.0

Offsetting of Financial Liabilities and Derivative Liabilities

	As of June 30, 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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
Description:					
Derivatives [(1)]	$ (205.1)	$ 14.3	$ (190.8)	$ 0.9	$ (189.9)
Total	$ (205.1)	$ 14.3	$ (190.8)	$ 0.9	$ (189.9)

(1) Includes $9.3 million of cash collateral at June 30, 2013.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 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.

	June 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Interest rate contracts [(1)]	$	$ (140.3)	$	$ (140.3)	$	$ (309.0)	$	$ (309.0)
Commodity contracts:								

Financial		14.6	25.9	40.5		7.2	8.4	15.6
Physical			14.0	14.0			6.1	6.1
Commodity options			6.9	6.9			6.4	6.4
Total	$	$ (125.7)	$ 46.8	$ (78.9)	$	$ (301.8)	$ 20.9	$ (280.9)

(1) Includes $9.3 million of cash collateral at June 30, 2013.

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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 June 30, 2013 [2] (in millions)	Valuation Technique	Unobservable Input	Range [1] Lowest	Range [1] Highest	Weighted Average	Units
Commodity Contracts - Financial							
Natural Gas	$ 3.8	Market Approach	Forward Gas Price	3.30	4.17	3.66	MMBtu
NGLs	$ 22.1	Market Approach	Forward NGL Price	0.24	1.99	1.16	Gal
Commodity Contracts -Physical							
Natural Gas	$ 1.0	Market Approach	Forward Gas Price	3.30	4.49	3.74	MMBtu
Crude Oil	$ 1.4	Market Approach	Forward Crude Price	86.72	108.41	96.92	Bbl
NGLs	$ 12.6	Market Approach	Forward NGL Price	0.02	2.49	0.71	Gal
Power	$ (1.0)	Market Approach	Forward Power Price	30.74	39.91	33.06	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 6.9	Option Model	Option Volatility	25%	131%	40%	
Total Fair Value	$ 46.8						

(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 $0.4 million of losses.

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Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2012 [2] (in millions)	Valuation Technique	Unobservable Input	Range [1] Lowest	Highest	Weighted Average	Units
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.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2013 to June 30, 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)	13.1	31.6	0.7	45.4
Included in other comprehensive income	13.5			13.5
Purchases, issuances, sales and settlements:				
Purchases			1.1	1.1
Settlements [2]	(9.1)	(23.7)	(1.3)	(34.1)
Ending balance as June 30, 2013	$ 25.9	$ 14.0	$ 6.9	$ 46.8
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ 23.6	$ 13.9	$ 2.2	$ 39.7

(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.

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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 June 30, 2013 and December 31, 2012.

			At June 30, 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	1,682,606	$ 3.47	$ 3.70	$ 0.1	$ (0.5)	$ 0.2	$ (0.3)
	NGL	313,000	$ 53.84	$ 56.23	$	$ (0.8)	$ 1.4	$
	Crude Oil		$	$	$	$	$ 0.2	$
Receive fixed/pay variable	Natural Gas	3,007,500	$ 4.72	$ 3.53	$ 3.6	$	$ 7.8	$
	NGL	2,568,056	$ 50.93	$ 45.10	$ 16.2	$ (1.2)	$ 9.3	$ (9.9)
	Crude Oil	933,096	$ 92.36	$ 95.13	$ 2.6	$ (5.2)	$ 6.3	$ (8.8)
Receive variable/pay variable	Natural Gas	27,438,000	$ 3.58	$ 3.56	$ 0.7	$ (0.3)	$ 1.2	$ (0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	1,475,000	$ 33.92	$ 34.68	$ 0.5	$ (1.6)	$ 0.6	$ (0.8)
	Crude Oil	125,475	$ 96.46	$ 96.63	$ 0.2	$ (0.2)	$ 0.4	$ (0.4)
Receive fixed/pay variable	NGL	3,056,484	$ 35.94	$ 33.05	$ 9.2	$ (0.3)	$ 2.6	$ (2.2)
	Crude Oil	213,075	$ 95.88	$ 96.40	$ 0.3	$ (0.4)	$ 0.2	$ (1.0)
Receive variable/pay variable	Natural Gas	36,846,656	$ 3.58	$ 3.57	$ 0.6	$ (0.3)	$ 0.9	$
	NGL	9,359,030	$ 39.49	$ 39.03	$ 7.8	$ (3.6)	$ 5.2	$ (2.3)
	Crude Oil	1,072,720	$ 97.76	$ 96.32	$ 3.0	$ (1.5)	$ 6.4	$ (3.0)
Pay fixed	Power [4]	21,643	$ 34.10	$ 42.82	$	$ (0.2)	$	$ (0.5)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 3.82	$ 5.22	$	$	$	$
	NGL	75,000	$ 74.54	$ 78.98	$	$ (0.3)	$	$
Receive fixed/pay variable	Natural Gas	2,511,900	$ 4.01	$ 3.80	$ 0.5	$	$ 0.2	$
	NGL	955,050	$ 66.09	$ 58.47	$ 7.9	$ (0.7)	$ 0.9	$ (2.7)
	Crude Oil	1,361,955	$ 94.22	$ 90.03	$ 7.2	$ (1.5)	$ 5.4	$ (2.7)
Receive variable/pay variable	Natural Gas	8,112,500	$ 3.84	$ 3.83	$ 0.2	$ (0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive fixed/pay variable	NGL	8,631	$ 40.40	$ 37.16	$	$	$	$
Receive variable/pay variable	Natural Gas	32,502,275	$ 3.84	$ 3.83	$ 0.8	$ (0.4)	$ 0.5	$
	NGL	5,389,425	$ 24.27	$ 24.15	$ 0.9	$ (0.3)	$	$
Pay fixed	Power [4]	58,608	$ 32.68	$ 46.58	$	$ (0.8)	$	$ (0.8)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$ 75.04	$ 1.5	$	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 85.55	$ 10.4	$	$ 6.8	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,517,025	$ 4.18	$ 4.14	$ 0.5	$ (0.1)	$ 0.4	$
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 82.79	$ 0.7	$	$ 0.5	$
Physical Contracts								
Receive variable/pay variable	Natural Gas	783,240	$ 4.45	$ 4.33	$ 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 June 30, 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 $0.7 million of losses at June 30, 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.

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The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2013 and December 31, 2012.

			At June 30, 2013				At December 31, 2012	
			Strike	Market	Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Price [2]	Price [2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2013								
Puts (purchased)	Natural Gas	828,000	$ 4.18	$ 3.48	$ 0.6	$	$ 1.4	$
	NGL	276,000	$ 31.26	$ 23.13	$ 2.6	$	$ 3.7	$
Portion of option contracts maturing in 2014								
Puts (purchased)	NGL	401,500	$ 52.21	$ 45.06	$ 4.4	$	$ 1.3	$
Calls (written)	NGL	273,750	$ 57.93	$ 42.55	$	$ (0.7)	$	$

(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 June 30, 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]	June 30, 2013	December 31, 2012
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 625	4.01%	$ (6.4)	$ (22.6)
Interest Rate Swaps Pay Fixed	Non-qualifying	$		$	$ (2.2)
Interest Rate Swaps Pay Float	Non-qualifying	$		$	$ 2.4
Contracts maturing in 2014					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$		$	$ (0.6)
Contracts maturing in 2015					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.5)	$ (6.7)
Contracts maturing in 2017					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (10.1)	$ (16.0)
Contracts maturing in 2018					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 325	1.26%	$ 2.8	$ (1.8)
Contracts settling prior to maturity					
2012 Pre-issuance Hedges	Cash Flow Hedge	$		$	$ (154.0)
2013 Pre-issuance Hedges[3]	Cash Flow Hedge	$ 800	4.47%	$ (121.3)	$ (84.4)
2014 Pre-issuance Hedges	Cash Flow Hedge	$ 1,050	3.71%	$ (36.6)	$ (45.3)
2016 Pre-issuance Hedges	Cash Flow Hedge	$ 100	2.08%	$ 43.0	$ 8.4

(1) Interest rate derivative contracts are based on the one-month or three-month LIBOR.
(2) The fair value is determined from quoted market prices at June 30, 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 $5.2 million of losses at June 30, 2013 and $13.7 million of gains at December 31, 2012.
(3) Includes $9.3 million of cash collateral at June 30, 2013.

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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 six month periods ended June 30, 2013 and 2012, respectively. Our income tax expense is $14.2 million and $1.7 million and $16.0 million and $3.8 million for the three and six month periods ended June 30, 2013 and 2012, respectively.

At June 30, 2013 and December 31, 2012, we have included a current income tax payable of $0.5 million and $7.7 million in Property and other taxes payable on our consolidated statements of financial position, respectively. In addition, at June 30, 2013 and December 31, 2012, we have included a deferred income tax payable of $16.3 million and $3.0 million, respectively, in Deferred income tax liability, 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. Included in the $16.3 million is $12.1 million due to a new tax bill that went into effect in June 2013, as discussed below.

The Texas Legislature passed House Bill 500 and the tax bill was subsequently signed into law in June 2013. The most significant change in the law for the Partnership is that House Bill 500, or HB 500, allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as Cost of Goods Sold, or COGS, its depreciation, operations, and maintenance costs related to the services provided. Under the new law, the Partnership is allowed additional deductions against its income for Texas Margin Tax purposes. We have recorded an additional Deferred income tax liability on our consolidated statements of financial position of approximately $12.1 million for the three month period ended June 30, 2013 as a result of this new tax law. On a go forward basis, the Partnership s future effective tax rate in the State of Texas will be lower as a result of this law change.

Accounting for Uncertainty in Income Taxes

The following is a reconciliation of our beginning and ending balance of unrecognized tax benefits in millions:

	(in millions)
Unrecognized tax benefits at December 31, 2012	$ 21.8
Additions for tax positions taken in current period	6.8
Unrecognized tax benefits at June 30, 2013	$ 28.6

Additions for tax positions taken in the current period are for a state income tax refund claim and related accruals. As of June 30, 2013, the entire balance of unrecognized tax benefits would favorably affect our effective tax rate in future periods if recognized. It is reasonably possible that our liability for unrecognized tax benefits will increase by $3.0 million during the next twelve months. As of June 30, 2013, $0.6 million of accrued interest income and $0.5 million of penalties have not been included in the balance of unrecognized tax benefits. The Company recognizes accrued interest income and penalties related to unrecognized tax benefits in interest income and penalties when the related unrecognized tax benefits are recognized.

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.

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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:

	For the three month period ended June 30, 2013				
	Liquids	Natural Gas	Marketing (in millions)	Corporate (1)	Total
Total revenue	$ 366.3	$ 1,138.9	$ 485.7	$	$ 1,990.9
Less: Intersegment revenue		309.7	8.5		318.2
Operating revenue	366.3	829.2	477.2		1,672.7
Cost of natural gas		640.9	474.6		1,115.5
Environmental costs, net of recoveries	5.2				5.2
Operating and administrative	98.4	115.1	1.3	3.2	218.0
Power	29.2				29.2
Depreciation and amortization	60.4	35.4			95.8
	193.2	791.4	475.9	3.2	1,463.7
Operating income (loss)	173.1	37.8	1.3	(3.2)	209.0
Interest expense				79.5	79.5
Other income				0.3	0.3
Allowance for equity used during construction				8.1	8.1
Income (loss) from continuing operations before income tax expense	173.1	37.8	1.3	(74.3)	137.9
Income tax expense				14.2	14.2
Net income (loss)	173.1	37.8	1.3	(88.5)	123.7
Less: Net income attributable to: Noncontrolling interest				18.4	18.4
Series 1 preferred unit distributions				13.1	13.1
Accretion of discount on Series 1 preferred units				2.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 173.1	$ 37.8	$ 1.3	$ (122.3)	$ 89.9

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

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	For the three month period ended June 30, 2012				
	Liquids	Natural Gas	Marketing (in millions)	Corporate (1)	Total
Total revenue	$ 363.5	$ 1,098.8	$ 286.8	$	$ 1,749.1
Less: Intersegment revenue	0.9	192.3	4.8		198.0
Operating revenue	362.6	906.5	282.0		1,551.1
Cost of natural gas		691.7	283.5		975.2
Environmental costs, net of recoveries	22.7				22.7
Operating and administrative	93.5	110.6	1.6	0.5	206.2
Power	37.4				37.4
Depreciation and amortization	52.4	33.7			86.1
	206.0	836.0	285.1	0.5	1,327.6
Operating income (loss)	156.6	70.5	(3.1)	(0.5)	223.5
Interest expense				81.8	81.8
Other expense				(0.3)	(0.3)
Income (loss) from continuing operations before income tax expense	156.6	70.5	(3.1)	(82.6)	141.4
Income tax expense				1.7	1.7
Net income (loss)	156.6	70.5	(3.1)	(84.3)	139.7
Less: Net income attributable to the noncontrolling interest				15.1	15.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 156.6	$ 70.5	$ (3.1)	$ (99.4)	$ 124.6

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

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	As of and for the six month period ended June 30, 2013				
	Liquids	Natural Gas	Marketing (in millions)	Corporate [1]	Total
Total revenue	$ 699.2	$ 2,353.3	$ 893.5	$	$ 3,946.0
Less: Intersegment revenue		558.4	21.9		580.3
Operating revenue	699.2	1,794.9	871.6		3,365.7
Cost of natural gas		1,436.8	870.1		2,306.9
Environmental costs, net of recoveries	183.7				183.7
Operating and administrative	185.1	221.6	2.6	3.6	412.9
Power	62.8				62.8
Depreciation and amortization	117.2	70.8			188.0
	548.8	1,729.2	872.7	3.6	3,154.3
Operating income (loss)	150.4	65.7	(1.1)	(3.6)	211.4
Interest expense				155.9	155.9
Other income				0.6	0.6
Allowance for equity used during construction				15.9	15.9
Income (loss) from continuing operations before income tax expense	150.4	65.7	(1.1)	(143.0)	72.0
Income tax expense				16.0	16.0
Net income (loss)	150.4	65.7	(1.1)	(159.0)	56.0
Less: Net income attributable to: Noncontrolling interest				34.0	34.0
Series 1 preferred unit distributions				13.1	13.1
Accretion of discount on Series 1 preferred units				2.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 150.4	$ 65.7	$ (1.1)	$ (208.4)	$ 6.6
Total assets [2]	$ 7,811.0	$ 5,266.5	$ 63.9	$ 159.6	$ 13,301.0
Capital expenditures (excluding acquisitions)	$ 733.4	$ 125.1	$	$ 8.6	$ 867.1

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

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

	As of and for the six month period ended June 30, 2012				
	Liquids	Natural Gas	Marketing (in millions)	Corporate [1]	Total
Total revenue	$ 686.1	$ 2,486.3	$ 623.2	$	$ 3,795.6
Less: Intersegment revenue	1.2	410.6	13.2		425.0
Operating revenue	684.9	2,075.7	610.0		3,370.6
Cost of natural gas		1,657.3	614.8		2,272.1
Environmental costs, net of recoveries	25.9				25.9
Operating and administrative	170.7	228.2	3.3	0.9	403.1
Power	78.6				78.6
Depreciation and amortization	102.9	66.8			169.7
	378.1	1,952.3	618.1	0.9	2,949.4
Operating income (loss)	306.8	123.4	(8.1)	(0.9)	421.2
Interest expense				165.4	165.4
Other expense				(0.3)	(0.3)
Income (loss) from continuing operations before income tax expense	306.8	123.4	(8.1)	(166.6)	255.5
Income tax expense				3.8	3.8
Net income (loss)	306.8	123.4	(8.1)	(170.4)	251.7
Less: Net income attributable to the noncontrolling interest				28.1	28.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 306.8	$ 123.4	$ (8.1)	$ (198.5)	$ 223.6
Total assets [2]	$ 6,474.4	$ 4,840.5	$ 135.1	$ 86.2	$ 11,536.2
Capital expenditures (excluding acquisitions)	$ 423.2	$ 221.0	$	$ 7.5	$ 651.7

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

(2) For comparability purposes, we have made reclassifications of approximately $48.6 million out of Total Corporate assets into Total Natural Gas assets for the June 30, 2012 balances. The reclassification represents our long term equity investment in the Texas Express NGL system as of June 30, 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 and six month periods ended June 30, 2013, we had a net under collection of revenue for our Southern Access Pipeline primarily due to our volumes being lower than the forecasted volumes used for our April 2013 surcharge filing, partially offset by higher than anticipated power credit adjustments. As a result, for the three and six month periods ended June 30, 2013, we adjusted our revenues by a net increase of $1.4 million and $4.1 million, respectively, on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at June 30, 2013. The amounts will be included in our tolls beginning April 2014 when we update our transportation rates.

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 and six month periods ended June 30, 2013, we decreased our revenues by $0.1 million and $0.6 million, respectively, on our consolidated statement of income with a corresponding amount increasing the regulatory liability on our consolidated statement of financial position at June 30, 2013. At June 30, 2013 and December 31, 2012, we had a $0.1 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 the three and six month periods ended June 30, 2013, we had under collected revenue on our Alberta Clipper Pipeline primarily due to our actual volumes being lower than the forecast volumes used for our April 2013 surcharge filing. As a result, for the three and six month periods ended June 30, 2013, we increased our revenues by $5.3 million and $4.1 million, respectively, on our consolidated statement of income with a corresponding decrease in the regulatory liability on our consolidated statement of financial position at June 30, 2013 for the differences in transportation volumes. The amounts will be included in our tolls beginning April 2014 when we update our transportation rates to account for the lower delivered volumes.

For 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 and six month periods ended June 30, 2013, we increased our revenues by $3.9 million and $8.5 million, respectively, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position at June 30, 2013. As of June 30, 2013 and December 31, 2012, we had regulatory liabilities of $7.9 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 liabilities associated with this contractual obligation in Accounts payable and other, on our consolidated statements of financial position. The amortization for this contractual obligation reflects the related transportation rate adjustment in the subsequent year. At June 30, 2013 and December 31, 2012, we had $10.2 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 in the following year. For the six month periods ended June 30, 2013 and 2012, we increased our revenues by $2.3 million and $1.6 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 June 30, 2013 and December 31, 2012, we had $6.3 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 six month periods ended June 30, 2013 and 2012, we increased our revenues by $3.0 million and $3.6 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 June 30, 2013 these amounts have been refunded.

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 75-mile Replacement and Mainline Expansion Projects, we recorded $15.9 million of AEDC in Property, plant and equipment on our consolidated statement of financial position at June 30, 2013, and corresponding $8.1 million and $15.9 million of Allowance for equity used during construction in our consolidated statement of income for the three and six month periods ended June 30, 2013, respectively, with no similar transactions in the same periods 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 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.

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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.

On May 31, 2013, we filed FERC tariffs with effective dates of July 1, 2013, 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 1.045923, which was issued by FERC on May 15, 2013, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with 18 C.F.R.342.3 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 $0.05 per barrel to an average of approximately $1.98 per barrel.

On July 25, 2013, we received a complaint from one of our shippers on our North Dakota system that our rates are not reasonable as it relates to our phase 6 expansion. We are in the process of evaluating this complaint.

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 18 C.F.R.342.3 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 six month period ended June 30, 2013	2012
	(in millions)	
Discount accretion	$ 0.4	$ 0.3
Amortization of debt issuance and hedging costs	3.6	6.5
Impairment of Marshall homes	2.7	
Loss on sale of assets	1.1	
Other	(0.5)	0.4
	$ 7.3	$ 7.2

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15. SUBSEQUENT EVENTS

Distribution to Partners

On July 29, 2013, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2013. The distribution will be paid to unitholders of record as of August 7, 2013, of our available cash of $206.8 million at June 30, 2013, or $0.5435 per limited partner unit. Of this distribution, $177.3 million will be paid in cash, $28.9 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 July 29, 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 $11.0 million to the noncontrolling interest in the Series AC, while $5.5 million will be paid to us.

Revised Credit Agreement

On July 3, 2013, we amended our 364-Day Credit Facility, dated as of July 6, 2012, with JPMorgan Chase Bank, National Association, to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on July 24, 2013, we further amended the 364-Day Credit Facility, adding a new lender and increasing our aggregate commitments under the facility by another $50.0 million. After these amendments, our 364-day Credit Facility now provides aggregate lending commitments of $1.2 billion.

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.

Initial Public Offering of Midcoast Energy Partners, L.P.

In May 2013, we formed Midcoast Energy Partners, L.P., or MEP, which currently is our wholly-owned subsidiary. On June 14, 2013, MEP filed a Registration Statement on Form S-1 with the Securities and Exchange Commission related to MEP s proposed initial public offering of common units representing limited partner interests in MEP. If the proposed offering closes, MEP s initial asset will consist of an approximate 40% ownership interest in our existing natural gas and NGL midstream business. We will retain ownership of the general partner and all the incentive distribution rights in MEP. We expect that MEP will sell a minority of its total limited partner interests in the offering, which is expected to occur in the second half of 2013.

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.

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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 and six month periods ended June 30, 2013 and 2012.

	For the three month period ended June 30, 2013	For the three month period ended June 30, 2012	For the six month period ended June 30, 2013	For the six month period ended June 30, 2012
	(unaudited; in millions)			
Operating income				
Liquids	$ 173.1	$ 156.6	$ 150.4	$ 306.8
Natural Gas	37.8	70.5	65.7	123.4
Marketing	1.3	(3.1)	(1.1)	(8.1)
Corporate, operating and administrative	(3.2)	(0.5)	(3.6)	(0.9)
Total operating income	209.0	223.5	211.4	421.2
Interest expense	79.5	81.8	155.9	165.4
Other income (expense)	0.3	(0.3)	0.6	(0.3)
Allowance for equity used during construction	8.1		15.9	
Income before income tax expense	137.9	141.4	72.0	255.5
Income tax expense	14.2	1.7	16.0	3.8
Net income	123.7	139.7	56.0	251.7
Less: Net income attributable to:				
Noncontrolling interest	18.4	15.1	34.0	28.1
Series 1 preferred unit distributions	13.1		13.1	
Accretion of discount on Series 1 preferred units	2.3		2.3	
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 89.9	$ 124.6	$ 6.6	$ 223.6

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 following factors primarily affected the $16.5 million increase and the $156.4 million decrease in operating income for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods of 2012:

Increased operating revenue of $33.4 million and $43.3 million for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods in 2012, primarily due to higher indexed tariff rates on our Lakehead, North Dakota and Ozark systems. We also had higher revenue

during the three months ended June 30, 2013 due to $13.4 million of revenue from our Bakken expansion, which has ship or pay agreements in place, and $3.6 million of revenue from our Berthold Rail system. The increased revenues were partially offset by decreased average daily delivery volumes on our three systems of $31.6 million and $48.2 million for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods in 2012;

Increased operating revenue of $3.8 million and $11.5 million due to the collection of fees from our Cushing storage terminal facilities for the three and six month periods ended June 30, 2013, respectively;

Decreased unrealized, non-cash, mark-to-market net gains of $17.7 million and $11.5 million for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods in 2012, related to derivative financial instruments;

Decreased environmental expense of $17.5 million for the three month period ended June 30, 2013 as compared with the same period in 2012, primarily due to a net decrease of $22.0 million in accrued expenses for the Line 6B crude oil release, net of insurance receivables, partially offset by $7.0 million of additional accrued expenses related to our Cushing storage crude oil release recognized in the second quarter 2013. Environmental expense increased $157.8 million for the six month period ended June 30, 2013 as compared to the same period in 2012, primarily due to a net increase of $153.0 million in accrued expenses for the Line 6B crude oil release, net of insurance receivables, for supplementary work required by the Environmental Protection Agency, or the EPA, during the first half of 2013 compared to the same period in 2012;

Increased operating and administrative expenses of $4.9 million and $14.4 million for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods in 2012 primarily due to additional integrity related costs and increased property tax expenses for both periods and increased workforce related costs for the six month period;

Decreased power costs of $8.2 million and $15.8 million due to decreased average daily delivery volumes on our systems for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods in 2012; and

Increased depreciation expense of $8.0 million and $14.3 million for the three and six month periods ended June 30, 2013, respectively, when compared to the same periods in 2012, directly attributable to additional assets placed into service.

Natural Gas

The operating income of our Natural Gas business for the three and six month periods ended June 30, 2013 decreased $32.7 million and $57.7 million, for the three and six month periods ended June 30, 2013, respectively, when compared to the same period in 2012, primarily due to the following:

Decreased operating income of approximately $15.4 million and $28.1 million for the three and six month periods ended June 30, 2013, respectively, when compared to the same period in 2012, primarily due to the decline in NGL prices;

Decreased operating income of $10.2 million and $12.6 million for the three and six month periods ended June 30, 2013, respectively, 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;

Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings of $9.1 million and $22.2 million, respectively, when compared to the same period in 2012, due to a decline in total NGL production, primarily due to ethane rejection in the Mid-Continent and lower NGL prices when compared to the same period in 2012;

Increased pipeline integrity costs of $3.7 million and $5.2 million for the three and six month periods ended June 30, 2013, respectively, as part of the operational risk management plan to ensure our systems are safe and to maintain our existing pipelines; and

Increased depreciation expense of $1.7 and $4.0 million, for the three and six month periods ended June 30, 2013, respectively, 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 for the three and six month periods ended June 30, 2013, as compared with the same period in 2012 primarily due to:

Increased operating income of $5.7 million and $5.3 million for the three and six month periods ended June 30, 2013, respectively, due to decreased non-cash charges to inventory, to reduce the cost basis of our natural gas inventory to net realizable value, when compared with the same periods in 2012.

Decreased current year costs of $7.4 million for six month period ended June 30, 2013, 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; and

Decreased supporting costs of $1.7 million and $6.8 million for the three and six month periods ended June 30, 2013, respectively, due to favorable maintenance, supplies and other outside services requirements when compared to 2012.

Marketing

The increases in operating results of our Marketing segment for the three and six month periods ended June 30, 2013, when compared to the same periods in 2012, were due to net gains associated with our storage derivative instruments, an improved pricing environment and the expiration of certain transportation fees for natural gas being transported on a third party pipeline.

In addition, for the six month period ended June 30, 2013 we recorded only $0.2 million of non-cash charges in inventory to reduce the cost basis of our natural gas inventory to net realizable value, compared with $2.0 million of similar charges recorded for the same period in 2012.

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

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

	For the three month period ended June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(unaudited; in millions)			
Liquids segment				
Non-qualified hedges	$ 3.2	$ 21.1	$ 1.2	$ 12.3
Natural Gas segment				
Hedge ineffectiveness	1.8	6.9	2.3	5.1
Non-qualified hedges	19.2	24.3	20.0	29.8
Marketing				
Non-qualified hedges	1.3	(0.6)	(1.5)	(2.4)
Commodity derivative fair value net gains	25.5	51.7	22.0	44.8
Corporate				
Hedge ineffectiveness	1.1	0.3	0.6	0.3
Non-qualified interest rate hedges	(0.1)	(0.2)	(0.3)	(0.2)
Derivative fair value net gains	$ 26.5	$ 51.8	$ 22.3	$ 44.9

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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 June 30, 2013	For the three month period ended June 30, 2012	For the six month period ended June 30, 2013	For the six month period ended June 30, 2012
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 366.3	$ 362.6	$ 699.2	$ 684.9
Environmental costs, net of recoveries	5.2	22.7	183.7	25.9
Operating and administrative	98.4	93.5	185.1	170.7
Power	29.2	37.4	62.8	78.6
Depreciation and amortization	60.4	52.4	117.2	102.9
Operating expenses	193.2	206.0	548.8	378.1
Operating income	$ 173.1	$ 156.6	$ 150.4	$ 306.8
Operating Statistics				
Lakehead system:				
United States [(1)]	1,281	1,435	1,375	1,452
Province of Ontario [(1)]	402	376	384	383
Total Lakehead system deliveries [(1)]	1,683	1,811	1,759	1,835
Barrel miles (billions)	113	122	233	245
Average haul (miles)	739	738	732	735
Mid-Continent system deliveries [(1)]	170	235	196	234
North Dakota system:				
Trunkline [(1)]	148	217	136	219
Gathering [(1)]	3	2	3	3
Total North Dakota system deliveries [(1)]	151	219	139	222
Total Liquids Segment Delivery Volumes [(1)]	2,004	2,265	2,094	2,291

(1) Average barrels per day in thousands.

Three month period ended June 30, 2013 compared with three month period ended June 30, 2012

Our operating revenue of our Liquids segment was positively impacted by the filing of tariffs that became effective July 1, 2012 and April 1, 2013 to increase the rates for our Lakehead, North Dakota and Ozark systems with Federal Energy Regulatory Commission, or FERC. The rate increases that became effective July 1, 2012 resulted from application of the index allowed by FERC. The rate increases effective April 1, 2013 primarily resulted from the annual tariff rate adjustment for our Lakehead system to reflect our projected costs and throughput for 2013, true-ups for the prior year for the Lakehead system and recovery of costs related to several of our major capital projects on our Lakehead and North Dakota systems. These changes in index comprised approximately $33.4 million of the increase in operating revenue for the three month period ended June 30, 2013 when compared to the same period in 2012.

Additionally, our operating revenue increased by $3.8 million during the three month period ended June 30, 2013, when compared with the same period in 2012, 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.

Partially offsetting the increase to operating revenue was the lower average daily delivery volumes on all our systems. Operating revenue decreased by $31.6 million for the three month period ended June 30, 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 systems was attributable to unplanned downstream refinery maintenance that impacted deliveries on our Lakehead system, as well as lower deliveries on our North Dakota system as rail was an alternative option available to our shippers. This loss of volume was slightly offset by $13.4 million of revenue from our Bakken expansion which has ship or pay agreements in place and $3.6 million of revenue from our Berthold Rail system.

The operating revenue also decreased for the three month period ended June 30, 2013, when compared with the same period in 2012, partly due to a $17.7 million decrease in unrealized, non-cash, mark-to-market net gains 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.

Environmental costs, net of recoveries decreased $17.5 million for the three month period ended June 30, 2013, when compared with the same period in 2012. During the three month period ended June 30, 2013, we increased our estimated costs related to the Line 6B crude oil release by $40.0 million attributable to further refinement and definition of the additional dredging scope per the EPA order and all associated environmental, permitting, waste removal and other related costs as compared to a $20.0 million increase in estimated costs related to the release during the same period in 2012. This was offset by $42.0 million of insurance recoveries related to the Line 6B crude oil release we recognized for the three month period ended June 30, 2013. We also recognized $7.0 million of environmental costs during the three months ended June 30, 2013 related to a crude oil release at our Cushing storage facility that occurred on May 18, 2013.

The operating and administrative expenses of our Liquids business increased $4.9 million for the three month period ended June 30, 2013, when compared with the same period in 2012, primarily due to additional integrity related costs of $2.2 million as part of the operational risk management plan to ensure our systems are safe and to maintain our existing pipelines and increased property tax expenses of $2.1 million. We recognized approximately $1.2 million of costs associated with the Line 14 hydrotesting during the three month period ended June 30, 2013 and expect a significant portion of the remaining costs will be incurred during the third quarter of 2013.

Power cost decreased $8.2 million for the year ended June 30, 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 $8.0 million for the three month period ended June 30, 2013 is directly attributable to the additional assets we have placed in service since the same period in 2012.

Six month period ended June 30, 2013 compared with six month period ended June 30, 2012

Our Liquids segment contributed $150.4 million of operating income during the six month period ended June 30, 2013, representing a $156.4 million decrease over the $306.8 million operating income for the same period in 2012. The components comprising the operating income of our Liquids business changed during the six month period ended June 30, 2013, as compared with the same period in 2012, primarily for the reasons noted above in our three month analysis, in addition to the factors discussed below.

Environmental costs, net of recoveries increased $157.8 million for the six month period ended June 30, 2013, when compared with the same period in 2012, of which $215.0 million is primarily attributable to

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additional work required by the Order we received on March 14, 2013, compared to $20.0 million in 2012. We also recognized $7.0 million for the six month period ended June 30, 2013 related to our Cushing storage terminal facility crude oil release as discussed above. These increases in environmental costs were partially offset by $42.0 million of insurance recoveries related to the Line 6B crude oil release we recognized for the three month period ended June 30, 2013.

In addition, the operating and administrative expenses of our Liquids business increased for the six month period ended June 30, 2013, when compared with the same period in 2012, due to additional workforce related costs of $5.4 million.

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 (in millions)	Expected In-Service Date	Funding
Eastern Access Projects			
Line 5, Line 62 Expansion, Line 6B Replacement	$ 2,070	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-Q3 2013	EEP
Sandpiper Project	2,500	Early 2016	EEP
Line 6B 75-mile Replacement Program	390	Q2-Q4 2013	EEP

(1) Jointly funded 25% by the Partnership and 75% by our General Partner under Eastern Access Joint Funding agreement. Estimated capital costs presented are before our General Partner s contributions.

(2) Jointly funded 25% by the Partnership and 75% 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 approximate 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.

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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 was placed into service in May 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 discussed Line 5 expansion completion, 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. From May 2012 through June 27, 2013, our General Partner funded the Eastern Access Projects at 60% under the Eastern Access Joint Funding agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we will have the option to increase our economic interest by up to 15 percentage points back to 40%.

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 the 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, 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 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. From December 2012 through June 27, 2013, the projects were 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. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for 2016, the Partnership will have the option to increase its economic interest by up to 15 percentage points back to 40%.

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. The 35-mile pipeline adjacent to Enbridge s Toledo Pipeline was completed and placed into service in May 2013. 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 an estimated cost of approximately $300 million.

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 by the end of the third 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. The new segments are being completed in components, with approximately 65 miles of segments placed in service since the first quarter of 2013. Subject to regulatory and other approvals related to two remaining 5-mile segments in Indiana, these new segments are expected to be placed in service in components by the end of 2013. The replacement program has been carried out in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. The total capital for this replacement program is now estimated to cost $390 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

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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 590-mile, 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 the third quarter of 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 the 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, or Enterprise Product s, ECHO crude oil terminal, or ECHO Terminal, in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013.

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. In June 2013, Enbridge announced a second open season to solicit additional commitments from shippers for capacity on the proposed pipeline. The diameter of the pipeline could be increased depending on the results of the open season which is set to close in August 2013. Subject to regulatory and other approvals, the project is expected to be placed into service in 2015.

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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 June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(unaudited; in millions)			
Operating revenues	$ 829.2	$ 906.5	$ 1,794.9	$ 2,075.7
Cost of natural gas	640.9	691.7	1,436.8	1,657.3
Operating and administrative	115.1	110.6	221.6	228.2
Depreciation and amortization	35.4	33.7	70.8	66.8
Operating expenses	791.4	836.0	1,729.2	1,952.3
Operating income	$ 37.8	$ 70.5	$ 65.7	$ 123.4
Operating Statistics (MMBtu/d)				
East Texas	1,211,000	1,291,000	1,231,000	1,305,000
Anadarko	972,000	1,062,000	968,000	1,002,000
North Texas	344,000	332,000	338,000	323,000
Total	2,527,000	2,685,000	2,537,000	2,630,000

Three month period ended June 30, 2013 compared with three month period ended June 30, 2012

The operating income of our Natural Gas business for the three month period ended June 30, 2013 decreased $32.7 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 $26.5 million for the three month period ended June 30, 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 physical 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. NGLs increased approximately 7% per composite barrel at our Conway pricing hub and decreased approximately 13% per composite barrel at our Mont Belvieu pricing hub, for the three month period ended June 30, 2013 as compared to the same period in 2012.

Recent shifts in supply and demand fundamentals for NGLs, particularly ethane and propane, have resulted in downward pressure on current and forward NGL prices. As a result, several plants were periodically rejecting ethane and selling these molecules as natural gas during the three months ended June 30, 2013. The segment gross margin for our gathering, processing and transportation business was affected by this decline in NGL prices, which resulted in approximately $15.4 million less segment gross margin for the three month period ended June 30, 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 June 30, 2013 decreased $9.1 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 June 30, 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 $10.2 million for the three month period ended June 30, 2013 compared to the same period of 2012, primarily related to realized gains on our fractioning hedges and hedge ineffectiveness.

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 June 30, 2013 and 2012:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(unaudited; in millions)			
Hedge ineffectiveness	$ 1.8	$ 6.9	$ 2.3	$ 5.1
Non-qualified hedges	19.2	24.3	20.0	29.8
Derivative fair value gains	$ 21.0	$ 31.2	$ 22.3	$ 34.9

The above decreases in gross margin for the three month period ended June 30, 2013, were partially offset by an increase of $5.7 million related to decreases in non-cash charges to inventory, to reduce the cost basis of our natural gas inventory to net realizable value, when compared with the same periods in 2012.

Operating and administrative costs of our Natural Gas segment increased $4.5 million for the three month period ended June 30, 2013 compared to the same period in 2012, primarily due to increased pipeline integrity costs of $3.7 million as part of the operational risk management plan to ensure our systems are safe and to maintain our existing pipelines and increased workforce cost of $2.1 million. These costs were partially offset by decreased supporting costs of $1.7 million.

Depreciation expense for our Natural Gas segment increased $1.7 million, for the three month period ended June 30, 2013 compared with the same period of 2012, due to additional assets that were put in service during 2012.

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Six month period ended June 30, 2013 compared with six month period ended June 30, 2012

The primary factors affecting the operating income of our Natural Gas business for the six month period ended June 30, 2013, as compared with the same period of 2012, are the same as noted in our three month analysis in addition to the factors discussed below.

Operating and administrative costs of our Natural Gas segment decreased $6.6 million for the six month period ended June 30, 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 $6.8 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 $5.2 million as part of the operational risk management plan.

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 (in millions)	Expected In-service Date	Funding
Beckville Cryogenic Processing Facility	$ 145	Early 2015	EEP
Texas Express NGL system	$ 400	Q3 2013	Joint [(1)]
Ajax Cryogenic Processing Plant	$ 230	Q3 2013	EEP

(1) Our ownership of the Texas Express NGL system 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 $145 million. 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 in early 2015.

Texas Express NGL system

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 NGL gathering system, collectively referred to as the Texas Express NGL system. In April 2012, DCP Midstream LLC, or DCP, announced plans to purchase a 10% ownership in the NGL pipeline portion of the Texas Express NGL system from Enterprise Products. After DCP s purchase, the NGL pipeline portion of the Texas Express NGL system is owned 35% by Enterprise Products, 35% by us, 20% by Anadarko and 10% by DCP, while the ownership in the new NGL gathering system will be owned 45% by Enterprise Products, 35% by us and 20% by Anadarko. Our portion of the total estimated cost is $400 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 new NGL gathering system will initially consist of approximately 116 miles of gathering lines that will connect the mainline to natural gas processing plants in the Anadarko/Granite Wash production

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area located in the Texas Panhandle and western Oklahoma and to Barnett Shale processing plants in North Texas. The gathering system is currently expected to include 270 miles of gathering lines by 2019. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the Texas Express NGL 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 the Texas Express NGL system 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 system. The pipeline and portions of the gathering system are expected to begin service in the third quarter of 2013.

The Texas Express NGL system will serve as a link between growing supply sources of NGLs in the Anadarko, Permian basins, Mid-Continent and Rockies regions of the United States, the primary demand markets on the United States Gulf Coast and will provide guaranteed NGL access to the primary United States petrochemical market located in Mont Belvieu. The Texas Express NGL system 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. Construction of the Ajax Plant was completed in April 2013 and is anticipated to be placed into service in the third quarter of 2013, corresponding with the completion of the Texas Express NGL system 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 June 30,		For the six month period ended June 30,	
	2013	2012	2013	2012
	(unaudited; in millions)			
Operating revenues	$ 477.2	$ 282.0	$ 871.6	$ 610.0
Cost of natural gas	474.6	283.5	870.1	614.8
Operating and administrative	1.3	1.6	2.6	3.3
Operating expenses	475.9	285.1	872.7	618.1
Operating income (loss)	$ 1.3	$ (3.1)	$ (1.1)	$ (8.1)

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.

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Three month period ended June 30, 2013 compared with three month period ended June 30, 2012

The operating results of our Marketing segment for the three month period ended June 30, 2013 increased by $4.4 million when compared to the same period in 2012.

Operating income for the three month period ended June 30, 2013 was positively affected by unrealized, non-cash, mark-to-market net gains of $1.3 million as compared with $0.6 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 gains for the three month period ended June 30, 2013, as compared to the same period in 2012, was primarily attributed to financial instruments used to hedge our storage positions. The net gains associated with our storage derivative instruments resulted from the narrowing 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.

Also contributing to the increase in operating results of our Marketing business, was the improvement of natural gas prices during the three month period ended June 30, 2013, when compared to the same period of 2012. This improved pricing environment led to additional opportunities to benefit from favorable price differentials between market centers. As a result, our marketing operations generated a $0.5 million gain for the three month period ended June 30, 2013, as compared to a $0.9 million loss for the same period in 2012.

Further contributing to the increase in operating results of our Marketing segment, for the three month period ended June 30, 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 June 30, 2013, as compared to the same period in 2012.

Six month period ended June 30, 2013 compared with six month period ended June 30, 2012

The components comprising our operating results changed during the six month period ended June 30, 2013, compared to the same period in 2012, for primarily the same reasons as in the three month analysis, in addition to the items noted below.

Operating results for the current year were positively affected by only $0.2 million of non-cash charges to inventory for the six month period ended June 30, 2013, compared to $2.0 million for the six month period ended June 30, 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.

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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 June 30, 2013	For the three month period ended June 30, 2012	For the six month period ended June 30, 2013	For the six month period ended June 30, 2012
	(unaudited; in millions)			
Operating and administrative expenses	$ 3.2	$ 0.5	$ 3.6	$ 0.9
Operating loss	(3.2)	(0.5)	(3.6)	(0.9)
Interest expense	79.5	81.8	155.9	165.4
Allowance for equity used during construction	8.1		15.9	
Other income (expense)	0.3	(0.3)	0.6	(0.3)
Income tax expense	14.2	1.7	16.0	3.8
Net loss	(88.5)	(84.3)	(159.0)	(170.4)
Less: Net income attributable to:				
Noncontrolling interest	18.4	15.1	34.0	28.1
Series 1 preferred unit distributions	13.1		13.1	
Accretion of discount on Series 1 Preferred units	2.3		2.3	
Net loss attributable to general and limited partners	$ (122.3)	$ (99.4)	$ (208.4)	$ (198.5)

Our interest cost for the three and six month periods ended June 30, 2013 and 2012 is comprised of the following:

	For the three month period ended June 30, 2013	For the three month period ended June 30, 2012	For the six month period ended June 30, 2013	For the six month period ended June 30, 2012
	(unaudited; in millions)			
Interest expense	$ 79.5	$ 81.8	$ 155.9	$ 165.4
Interest capitalized	12.1	8.2	26.4	14.7
Interest cost incurred	$ 91.6	$ 90.0	$ 182.3	$ 180.1
Weighted average interest rate	6.1%	6.5%	6.1%	6.5%

Three month period ended June 30, 2013 compared with three month period ended June 30, 2012

The $4.2 million increase in our net loss for the three month period ended June 30, 2013 as compared to the same period in 2012 was primarily attributable to an increase in income tax expense partially offset by an increase in AEDC.

Income tax expense increased $12.5 million for the three month period ended June 30, 2013 compared to the same period in 2012, primarily due to a $12.1 million of income tax expense recognized for the three month period ended June 30, 2013 related to a new law passed in the State of Texas. See Note 11. *Income Taxes* for further discussion regarding this new tax law.

The increase in net loss was partially offset by an $8.1 million increase in AEDC for the three month period ended June 30, 2013 compared to the same period 2012, primarily related to our Line 6B and Eastern Access projects.

Interest expense decreased $2.3 million for the three month period ended June 30, 2013, compared with the corresponding period in 2012, primarily due to an increase of $3.9 million in capitalized interest related to our

capital projects and a decreased weighted average interest rate. Partially offsetting the decrease in the interest expense was a higher weighted average outstanding debt balance due to an increase in the commercial paper balance slightly offset with the repayment of the $200 million senior unsecured note due 2013 in June 2013.

During the current quarter it was determined that a portion of forecasted short term debt transactions are not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer meet the cash flow hedging requirements. These terminations resulted in an increase in interest expense of $5.3 million for the three and six month periods ended June 30, 2013.

Six month period ended June 30, 2013 compared with six month period ended June 30, 2012

The results for corporate activities for the six month period ended June 30, 2013, compared to the same period in 2012, changed for the same reasons as noted in the three month analysis above.

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 $13.3 million and $15.1 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month periods ended June 30, 2013 and June 30, 2012 respectively. We allocated earnings derived from operating the Alberta Clipper pipeline in the amount of $26.2 million and $28.1 million to our General Partner for the six month periods ended June 30, 2013 and June 30, 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.

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 $5.1 million and $7.8 million to our General Partner for its 60% ownership of the EA interest for the three and six month periods ended June 30, 2013, respectively. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Series 1 Preferred Units

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner to issue and sell of 48,000,000 of our Series 1 Preferred Units, or Preferred Units, representing limited partner interests in the Partnership. The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price. For the three and six month periods ended June 30, 2013, we have recognized $13.1 million in Preferred Unit distributions, and $2.3 million for accretion of beneficial conversion option discounts on these units.

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LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had approximately $2.6 billion of liquidity available to us at June 30, 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	$	27.3
Total credit available under Credit Facilities [(1)]		3,100.0
Less: Amounts outstanding under Credit Facilities [(1)]		
Principal amount of commercial paper issuances		435.0
Letters of credit outstanding		74.0
Total	$	2,618.3

(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 financings. 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 financings, including monetization or disposition of non-core assets, but there can be no assurance that this funding can be obtained.

As of June 30, 2013, we had a working capital deficit of approximately $655.5 million and approximately $2.6 billion of liquidity to meet our ongoing operational, investing and finance needs as of June 30, 2013 as shown above, as well as the funding requirements associated with the environmental costs resulting from the crude oil release 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 debt 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

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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.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, or Preferred Units, representing limited partner interests in the Partnership for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, which is subject to reset every five years. In addition, quarterly cash distributions will not be payable on the Preferred Units during the first full eight quarters ending June 30, 2015, and instead accrue and accumulate the payment deferral, which is referred to as the Payment Deferral, and will be payable upon the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) the Partnership uses the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders and General Partner s capital and a decrease in Preferred Unitholders capital to reflect the fair value of the Preferred Units at issuance on the Partnership s consolidated statement of changes in partners capital for the six month period ended June 30, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders capital. The impact of the beneficial conversion feature is also included in earnings per unit for the three and six month periods ended June 30, 2013 and 2012.

Proceeds from the Preferred Unit issuance were used by the Partnership to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

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 a number of our i-units equal to the number of Listed Shares sold in the offering. We used 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 six month period ended June 30, 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.

On July 3, 2013, we amended our 364-Day Credit Facility, to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on July 24, 2013, we further amended the 364-Day Credit Facility, adding a new lender and increasing our aggregate commitments under the facility by another $50.0 million. After these amendments, our 364-day Credit Facility now provides aggregate lending commitments of $1.2 billion.

We refer to the Credit Facility and the 364-Day Credit Facility, collectively, as our Credit Facilities. Our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit, as of June 30, 2013, 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

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that policy into account, at June 30, 2013, we could borrow approximately $2.6 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	435.0
Letters of credit outstanding	74.0
Total amount we could borrow at June 30, 2013	$ 2,591.0

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 and six month periods ended June 30, 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 Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of our 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 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. At June 30, 2013, we were in compliance with the terms of our financial covenants.

Commercial Paper

At June 30, 2013, we had $435.0 million of commercial paper outstanding at a weighted average interest rate of 0.35%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately $724.7 million during the six month period ended June 30, 2013, which includes gross borrowings of $7,368.1 million and gross repayments of $8,092.8 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 June 30, 2013, we had approximately $324.0 million outstanding under the A1 Term Note.

The OLP paid a distribution of $28.7 million and $32.6 million to our General Partner and its affiliate during the six month periods ended June 30, 2013 and 2012, respectively, 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 $26.2 million and $28.1 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the six month periods ended June 30, 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, 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. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points back to 40%. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $5.1 million and $7.8 million to our General Partner for its ownership of the EA interest for the three and six month periods ended June 30, 2013, respectively. 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 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. From December 2012 through June 27, 2013, the projects were jointly funded by our

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General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest by up to 15 percentage points back to 40%. All other operations are captured by the Lakehead interests. We received $12.0 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to the Mainline Expansion Projects.

Our General Partner has made equity contributions totaling $36.7 million and $59.5 million to the OLP for the three and six month periods ended June 30, 2013, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects. No such contributions were made during the six month period ended June 30, 2012.

Accounts Receivable Sale Arrangements

On June 28, 2013, we and certain of our subsidiaries entered into a Receivables Purchase Agreement, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge, in exchange for cash. The Receivables Agreement and the transactions contemplated thereby were approved by a special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, current accounts receivables and accrued receivables, or the Receivables, of the Partnership s respective subsidiaries up to a monthly maximum of $350.0 million, of receivables from prior months that have not been collected, through December 2016. Following the sale and transfer of the Receivables to the Enbridge subsidiary, the Receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The primary objective of the accounts receivable transaction is to further enhance our available liquidity, and cash available from operations for payment of distributions, during the next few years until our large growth capital commitments are permanently funded.

Consideration for the Receivables sold is equivalent to the carrying value of the Receivables less a discount. The difference between the carrying value of the Receivables sold and the cash proceeds received is recognized in Operating and administrative expense in our consolidated statements of income. For the three and six month periods ended June 30, 2013, the loss stemming from the discount on the Receivables sold was not material. As of June 30, 2013, we sold and derecognized $213.0 million of our receivables to the Enbridge subsidiary of which $79.5 million were trade receivables and $133.5 million were accrued receivables for cash proceeds of $212.9 million.

As of June 30, 2013, we have $3.4 million included in Restricted cash on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary as of June 30, 2013. The Enbridge subsidiary retains the right to select a new collection agent at any time.

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 $3.0 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 $965 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 $992.5 million for the six month period ending June 30, 2013, including $48.8 million on core maintenance activities, $126.7 million in contributions to the Texas Express NGL system and $149.7 million of expenditures that were financed by contributions from our General Partner via the joint funding arrangement. At June 30, 2013, we had approximately $1.5 billion 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 the capital expenditures to approximate the following:

	Total Forecasted Expenditures (in millions)
Capital Projects	
Eastern Access Projects	$ 960
U.S. Mainline Expansions	325
North Dakota Expansion Program	150
Line 6B 75-mile Replacement Program	160
Liquids Integrity Program	400
Ajax Cryogenic Processing Plant	60
System Enhancements	590
Core Maintenance Activities	130
Joint Venture Projects	
Texas Express NGL System	215
	2,990
Less: Joint Funding by General Partner	965
	$ 2,025

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 six month period ended June 30, 2013, our cash flows were impacted by the approximate $23.6 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 $215.0 million, related to the Order received from the EPA during 2013.

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In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We will be receiving a partial recovery payment of $42.0 million from the other remaining insurers and have since amended our lawsuit, such that it now includes only one carrier. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit.

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 June 30, 2013 for each of the indicated calendar years:

	Notional	2013	2014	2015	2016	2017	Total [4]
			(in millions)				
Swaps							
Natural gas [1]	42,774,376	$ 3.6	$ 0.6	$	$	$	$ 4.2
NGL [2]	4,020,606	14.2	6.9	1.5			22.6
Crude Oil [2]	3,206,216	(2.6)	5.7	10.4	0.7		14.2
Options							
Natural gas puts purchased [1]	828,000	0.6					0.6
NGL puts purchased [2]	677,500	2.6	4.4				7.0
NGL call written [2]	273,750		(0.7)				(0.7)
Forward contracts							
Natural gas [1]	78,649,196	0.3	0.4	0.4	0.1		1.2
NGL [2]	19,288,570	12.0	0.6				12.6
Crude Oil [2]	1,411,270	1.4					1.4
Power [3]	80,251	(0.2)	(0.8)				(1.0)
Totals		$ 31.9	$ 17.1	$ 12.3	$ 0.8	$	$ 62.1

(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 $0.7 million of losses at June 30, 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 June 30, 2013 for each of the indicated calendar years:

	Notional Amount	2013	2014	2015	2016	2017	Thereafter	Total [1]
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 1,650.0	$ (6.4)	$ (8.6)	$ (6.1)	$ (2.2)	$ 2.7	$ 0.4	$ (20.2)
Pre-issuance hedges [2]	$ 1,950.0	(121.3)	(36.6)		43.0			(114.9)
		$ (127.7)	$ (45.2)	$ (6.1)	$ 40.8	$ 2.7	$ 0.4	$ (135.1)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $5.2 million of losses at June 30, 2013.
(2) Includes $9.3 million of cash collateral at June 30, 2013.

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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 six month period ended June 30, 2013	2012	Variance 2013 vs. 2012 Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 477.5	$ 356.5	$ 121.0
Investing activities	(993.8)	(657.3)	(336.5)
Financing activities	315.7	68.7	247.0
Net increase (decrease) in cash and cash equivalents	(200.6)	(232.1)	31.5
Cash and cash equivalents at beginning of year	227.9	422.9	(195.0)
Cash and cash equivalents at end of period	$ 27.3	$ 190.8	$ (163.5)

Operating Activities

Net cash provided by our operating activities increased $121.0 million for the six month period ended June 30, 2013, compared to the same period in 2012, is primarily due to:

- Decrease in net income of $195.7 million offset by non-cash items which primarily consisted of:
  - Increase of $162.2 million in environmental costs primarily attributed to the EPA Order;
  - Increase in deferred and state income taxes of $13.2 million and $7.4 million, primarily due to the new Texas Margin Tax law passed in the second quarter of 2013 and an uncertain tax benefit adjustment for the 2012 tax year, respectively;
  - Decrease in derivative net gains of $22.6 million; and
  - Offset by increased AEDC of $15.9 million.
- Decrease in our working capital accounts of $121.2 million as compared to the same period in 2012 were primarily affected by $115.9 million more of accrued receivables sold for the six month period ended June 30, 2013 as compared to collected in the same period in 2012.

Investing Activities

Net cash used in our investing activities during the six month period ended June 30, 2013 increased by $336.5 million, compared to the same period of 2012, primarily due to the following:

Additions to property, plant and equipment in 2013 related to various enhancement projects of approximately $215.4 million;

Additional cash contributions of $82.1 million and increased AIDC of $6.7 million associated with our joint venture project, Texas Express NGL system;

Decreased payments on our construction payables of $20.3 million; and

Increased restricted cash balance of $3.4 million for receivables collected from customers that we had previously sold to an indirect wholly owned subsidiary of Enbridge. For more information, refer to Note 8. *Related Parties-Sale of Accounts Receivable.*

Financing Activities

Net cash provided by our financing activities increased $247.0 million for the six month period ended June 30, 2013, compared to the same period in 2012, primarily due to the following:

- Increase in proceeds from the preferred unit issuance of $1,200.0 million;
- Increase in proceeds from i-unit issuance of $278.7 million; and
- Increase of $118.6 million in capital contributions from our General Partner and its affiliates for its ownership interest in the Mainline Expansion and Eastern Access Projects.

Offsetting the increases above were the following:

- Increased net repayments on our commercial paper of $1,119.7 million;
- Increased repayments on long-term debt of $200.0 million; and
- Increased $34.5 million of additional cash used for distributions to our partners in 2013.

SUBSEQUENT EVENTS

Distribution to Partners

On July 29, 2013, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2013. The distribution will be paid to unitholders of record as of August 7, 2013, of our available cash of $206.8 million at June 30, 2013, or $0.5435 per limited partner unit. Of this distribution, $177.3 million will be paid in cash, $28.9 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 July 29, 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 $11.0 million to the noncontrolling interest in the Series AC, while $5.5 million will be paid to us.

Revised Credit Agreement

On July 3, 2013, we amended our 364-Day Credit Facility, dated as of July 6, 2012, with JPMorgan Chase Bank, National Association, to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on July 24, 2013, we further amended the 364-Day Credit Facility, adding a new lender and increasing our aggregate commitments under the facility by another $50.0 million. After these amendments, our 364-day Credit Facility now provides aggregate lending commitments of $1.2 billion.

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 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.

On May 31, 2013, we filed FERC tariffs with effective dates of July 1, 2013, 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 1.045923, which was issued by FERC on May 15, 2013, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with 18 C.F.R.342.3 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 $0.05 per barrel to an average of approximately $1.98 per barrel.

On July 25, 2013, we received a complaint from one of our shippers on our North Dakota system that our rates are not reasonable as it relates to our phase 6 expansion. We are in the process of evaluating this complaint.

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 18 C.F.R.342.3 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 June 30, 2013.

Date of Maturity & Contract Type		Accounting Treatment	Notional	Average Fixed Rate (1)	Fair Value (2) at June 30, 2013	Fair Value (2) at December 31, 2012
			(dollars in millions)			
Contracts maturing in 2013						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 625	4.01%	$ (6.4)	$ (22.6)
Interest Rate Swaps	Pay Fixed	Non-qualifying	$		$	$ (2.2)
Interest Rate Swaps	Pay Float	Non-qualifying	$		$	$ 2.4
Contracts maturing in 2014						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$		$	$ (0.6)
Contracts maturing in 2015						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.5)	$ (6.7)
Contracts maturing in 2017						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (10.1)	$ (16.0)
Contracts maturing in 2018						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 325	1.26%	$ 2.8	$ (1.8)
Contracts settling prior to maturity						
2012	Pre-issuance Hedges	Cash Flow Hedge	$		$	$ (154.0)
2013	Pre-issuance Hedges(3)	Cash Flow Hedge	$ 800	4.47%	$ (121.3)	$ (84.4)
2014	Pre-issuance Hedges	Cash Flow Hedge	$ 1,050	3.71%	$ (36.6)	$ (45.3)
2016	Pre-issuance Hedges	Cash Flow Hedge	$ 100	2.08%	$ 43.0	$ 8.4

(1) Interest rate derivative contracts are based on the one-month or three-month LIBOR.

(2) The fair value is determined from quoted market prices at June 30, 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 $5.2 million of losses at June 30, 2013 and $13.7 million of gains at December 31, 2012.

(3) Includes $9.3 million of cash collateral at June 30, 2013.

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 June 30, 2013 and December 31, 2012.

			At June 30, 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	1,682,606	$ 3.47	$ 3.70	$ 0.1	$ (0.5)	$ 0.2	$ (0.3)
	NGL	313,000	$ 53.84	$ 56.23	$	$ (0.8)	$ 1.4	$
	Crude Oil		$	$	$	$	$ 0.2	$
Receive fixed/pay variable	Natural Gas	3,007,500	$ 4.72	$ 3.53	$ 3.6	$	$ 7.8	$
	NGL	2,568,056	$ 50.93	$ 45.10	$ 16.2	$ (1.2)	$ 9.3	$ (9.9)
	Crude Oil	933,096	$ 92.36	$ 95.13	$ 2.6	$ (5.2)	$ 6.3	$ (8.8)
Receive variable/pay variable	Natural Gas	27,438,000	$ 3.58	$ 3.56	$ 0.7	$ (0.3)	$ 1.2	$ (0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	1,475,000	$ 33.92	$ 34.68	$ 0.5	$ (1.6)	$ 0.6	$ (0.8)
	Crude Oil	125,475	$ 96.46	$ 96.63	$ 0.2	$ (0.2)	$ 0.4	$ (0.4)
Receive fixed/pay variable	NGL	3,056,484	$ 35.94	$ 33.05	$ 9.2	$ (0.3)	$ 2.6	$ (2.2)
	Crude Oil	213,075	$ 95.88	$ 96.40	$ 0.3	$ (0.4)	$ 0.2	$ (1.0)
Receive variable/pay variable	Natural Gas	36,846,656	$ 3.58	$ 3.57	$ 0.6	$ (0.3)	$ 0.9	$
	NGL	9,359,030	$ 39.49	$ 39.03	$ 7.8	$ (3.6)	$ 5.2	$ (2.3)
	Crude Oil	1,072,720	$ 97.76	$ 96.32	$ 3.0	$ (1.5)	$ 6.4	$ (3.0)
Pay fixed	Power [(4)]	21,643	$ 34.10	$ 42.82	$	$ (0.2)	$	$ (0.5)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 3.82	$ 5.22	$	$	$	$
	NGL	75,000	$ 74.54	$ 78.98	$	$ (0.3)	$	$
Receive fixed/pay variable	Natural Gas	2,511,900	$ 4.01	$ 3.80	$ 0.5	$	$ 0.2	$
	NGL	955,050	$ 66.09	$ 58.47	$ 7.9	$ (0.7)	$ 0.9	$ (2.7)
	Crude Oil	1,361,955	$ 94.22	$ 90.03	$ 7.2	$ (1.5)	$ 5.4	$ (2.7)
Receive variable/pay variable	Natural Gas	8,112,500	$ 3.84	$ 3.83	$ 0.2	$ (0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive fixed/pay variable	NGL	8,631	$ 40.40	$ 37.16	$	$	$	$
Receive variable/pay variable	Natural Gas	32,502,275	$ 3.84	$ 3.83	$ 0.8	$ (0.4)	$ 0.5	$
	NGL	5,389,425	$ 24.27	$ 24.15	$ 0.9	$ (0.3)	$	$
Pay fixed	Power [(4)]	58,608	$ 32.68	$ 46.58	$	$ (0.8)	$	$ (0.8)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$ 75.04	$ 1.5	$	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 85.55	$ 10.4	$	$ 6.8	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,517,025	$ 4.18	$ 4.14	$ 0.5	$ (0.1)	$ 0.4	$
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 82.79	$ 0.7	$	$ 0.5	$
Physical Contracts								
Receive variable/pay variable	Natural Gas	783,240	$ 4.45	$ 4.33	$ 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 June 30, 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 $0.7 million of losses at June 30, 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.

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The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2013 and December 31, 2012.

		At June 30, 2013			Fair Value [3]		At December 31, 2012 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	828,000	$ 4.18	$ 3.48	$ 0.6	$	$ 1.4	$
	NGL	276,000	$ 31.26	$ 23.13	$ 2.6	$	$ 3.7	$
Portion of option contracts maturing in 2014								
Puts (purchased)	NGL	401,500	$ 52.21	$ 45.06	$ 4.4	$	$ 1.3	$
Calls (written)	NGL	273,750	$ 57.93	$ 42.55	$	$ (0.7)	$	$

(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 June 30, 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.

	June 30, 2013	December 31, 2012
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.2	$
AA	(41.5)	(116.5)
A [2]	(47.1)	(147.7)
Lower than A	9.5	(16.7)
	$ (78.9)	$ (280.9)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $9.3 million of cash collateral at June 30, 2013.

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 June 30, 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 June 30, 2013.

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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 to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

Holders of our Series 1 Preferred Units have a distribution preference, which may adversely affect the value the Class A common units

The holders of our Series 1 Preferred Units, or Preferred Units, have a preferential right to distributions prior to distributions to the holders of our Class A common units. For the first eight full quarters ending June 30, 2015, the quarterly cash distributions will not be payable on the Preferred Units and instead accrue and accumulate and are payable on the earlier of May 8, 2018 or on our redemption of the Preferred Units. Thereafter, the distributions will be paid in cash on a quarterly basis. To the extent that we do not pay in full any distribution on the Preferred Units, the unpaid amount will accrue and accumulate until it is paid in full, and no distributions may be made on the common units during that time.

Item 5. Other Information

Mr. William M. Ramos, who has served as Controller of Enbridge Energy Company, Inc., our General Partner and of Enbridge Energy Management, L.L.C. or Enbridge Management, since October 2010, and will be assuming another position with an indirect wholly owned subsidiary of Enbridge Inc., the indirect parent of the General Partner. Mr. Ramos will assume his new role and resigned his position as Controller our General Partner and Enbridge Management on July 29, 2013. Commensurate with Mr. Ramos resignation, Ms. Noor Kaissi was appointed Controller of the General Partner and of Enbridge Management effective July 29, 2013. Ms. Kaissi, 41, served as Chief Auditor and in other managerial roles of the General Partner with responsibility for financial accounting, internal audit and controls from June 2005.

Item 6. Exhibits

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

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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: July 30, 2013	By: /s/ Mark A. Maki Mark A. Maki *President* *(Principal Executive Officer)*
Date: July 30, 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
3.1	Fifth Amended and Restated Agreement of Limited Partnership of the Partnership, dated May 8, 2013 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on May 13, 2013).
4.1	Series 1 Preferred Unit Purchase Agreement, dated May 7, 2013 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 13, 2013).
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).
10.3	Amendment No. 2 to Credit Agreement and Extension and Increase Agreement, dated as of July 3, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on July 5, 2013).
10.4	Option Interests Purchase Agreement, dated as of June 28, 2013, between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on July 5, 2013).
10.5	Registration Rights Agreement, dated as of May 7, 2013, by and between the Partnership and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on May 13, 2013).
10.6 *	Form of Indemnification Agreement, and Schedule of Omitted Agreements.
10.7 *	Form of Guarantee, and Schedule of Omitted Agreements.
10.8 *	Incremental Commitment Activation Notice to Credit Agreement, dated July 24, 2013, between the Partnership, the Borrower, 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.
10.9 *	New Lender Supplement to Credit Agreement, dated July 24, 2013, between the Partnership, the Borrower, 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.
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.

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Exhibit Number	Description
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.