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, 2009

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, TX 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

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

Large Accelerated Filer 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 76,088,834 Class A common units outstanding as of July 24, 2009.

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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. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as anticipate, believe, continue, estimate, expect, forecast, intend, may, plan, position, projection, strategy, could, should, would, or will or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. 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 our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see Risk Factors included in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2008 and in Part II, Item 1A of our quarterly reports on Form 10-Q.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(unaudited; in millions, except per share amounts)			
Operating revenue	$ 1,310.2	$ 2,932.2	$ 2,769.9	$ 5,367.5
Operating expenses				
Cost of natural gas (Notes 4 and 10)	895.0	2,614.3	1,997.1	4,713.1
Operating and administrative	138.1	121.8	275.8	238.5
Power	29.8	31.3	63.2	69.6
Depreciation and amortization (Note 5)	70.1	55.3	134.2	104.5
	1,133.0	2,822.7	2,470.3	5,125.7
Operating income	177.2	109.5	299.6	241.8
Interest expense	57.9	51.4	109.2	79.0
Other income (expense)	0.3	2.5	(0.2)	2.2
Income from continuing operations before income tax expense	119.6	60.6	190.2	165.0
Income tax expense	2.1	1.8	4.1	3.1
Net income	$ 117.5	$ 58.8	$ 186.1	$ 161.9
Net income allocable to limited partner units	$ 102.9	$ 47.4	$ 157.9	$ 139.5
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.88	$ 0.49	$ 1.37	$ 1.48
Weighted average limited partner units outstanding	116.1	96.3	115.6	94.4

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 months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Net income	$ 117.5	$ 58.8	$ 186.1	$ 161.9
Other comprehensive loss, net of tax benefit of $0.5, $1.0, $0.4 and $1.2, respectively (Note 10)	(81.9)	(164.2)	(76.3)	(190.5)
Comprehensive income (loss)	$ 35.6	$ (105.4)	$ 109.8	$ (28.6)

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 months ended June 30, 2009	2008
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 186.1	$ 161.9
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	134.2	104.5
Derivative fair value losses (Notes 10)		30.1
Inventory market price adjustments (Note 4)	3.4	
Other	14.0	10.9
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(22.1)	(14.9)
Due from General Partner and affiliates (Note 8)	21.5	(6.3)
Accrued receivables	122.5	(265.3)
Inventory (Note 4)	(7.6)	(21.3)
Current and long term other assets (Note 10)	(29.6)	(2.8)
Due to General Partner and affiliates (Note 8)	0.1	18.9
Accounts payable and other (Notes 3 and 10)	(25.5)	2.8
Accrued purchases	(54.1)	258.7
Interest payable	20.7	13.8
Property and other taxes payable	(3.5)	4.8
Settlement of interest rate derivatives	(0.7)	(22.1)
Net cash provided by operating activities	359.4	273.7
Cash used in investing activities		
Additions to property, plant and equipment (Note 5)	(543.9)	(672.1)
Changes in construction payables	(33.3)	(40.8)
Changes in restricted cash (Note 3 and 6)	0.1	
Other	(0.2)	(5.4)
Net cash used in investing activities	(577.3)	(718.3)
Cash provided by financing activities		
Net proceeds from unit issuances		221.8
Distributions to partners (Notes 7 and 13)	(186.5)	(137.0)
Repayments of long-term debt (Note 6)	(175.0)	
Net proceeds from issuances of long-term debt (Note 6)		790.2
Net borrowings (repayments) under Credit Facility (Note 6)	376.2	(150.0)
Net commercial paper repayments (Note 6)		(168.6)
Other	(4.0)	
Net cash provided by financing activities	10.7	556.4
Net increase (decrease) in cash and cash equivalents	(207.2)	111.8
Cash and cash equivalents at beginning of year	339.9	50.5
Cash and cash equivalents at end of period	$ 132.7	$ 162.3

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, 2009	December 31, 2008
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 132.7	$ 339.9
Restricted cash (Note 3 and 6)		0.1
Receivables, trade and other, net of allowance for doubtful accounts of $2.0 in 2009 and $2.6 in 2008	125.1	103.0
Due from General Partner and affiliates (Note 8)	19.0	40.5
Accrued receivables	384.4	507.3
Inventory (Note 4)	57.2	53.0
Other current assets (Note 10)	44.9	80.7
	763.3	1,124.5
Property, plant and equipment, net (Note 5)	7,293.4	6,722.9
Goodwill	256.5	256.5
Intangibles, net	86.8	88.7
Other assets, net (Note 10)	76.0	108.3
	$ 8,476.0	$ 8,300.9
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 8)	$ 48.3	$ 42.2
Accounts payable and other (Notes 3, 9 and 10)	147.8	225.3
Accrued purchases	327.0	381.2
Interest payable	54.7	34.0
Property and other taxes payable	29.3	32.8
Current maturities of long-term debt (Note 6)	251.4	420.7
	858.5	1,136.2
Long-term debt (Note 6)	3,599.9	3,223.4
Notes payable to affiliate	130.0	130.0
Other long-term liabilities (Notes 9 and 10)	72.0	84.4
	4,660.4	4,574.0
Commitments and contingencies (Note 9)		
Partners capital (Note 7)		
Class A common units (76,088,834 at June 30, 2009 and December 31, 2008, respectively)	2,056.2	2,104.0
Class B common units (3,912,750 at June 30, 2009 and December 31, 2008)	82.8	85.0
Class C units (20,875,333 and 19,688,968 at June 30, 2009 and December 31, 2008, respectively)	914.6	886.5
i-units (15,684,406 and 14,763,055 at June 30, 2009 and December 31, 2008, respectively)	574.8	553.8
General Partner	250.6	84.7
Accumulated other comprehensive income (loss) (Note 10)	(63.4)	12.9
	3,815.6	3,726.9
	$ 8,476.0	$ 8,300.9

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 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 accounting principles generally accepted in the United States of America 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, 2009 and December 31, 2008; and our results of operations and cash flows for the three and six month periods ended June 30, 2009 and 2008. We derived our consolidated statement of financial position as of December 31, 2008 from the audited financial statements included in our 2008 Annual Report on Form 10-K. Our results of operations for the three and six month periods ended June 30, 2009 should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of our natural gas business, timing and completion of our construction projects, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. 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, 2008.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER UNIT

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

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly	Up to $0.59	2%	98%
First Target Distribution	> $0.59 to $0.70	15%	85%
Second Target Distribution	> $0.70 to $0.99	25%	75%
Over Second Target Distribution	In excess of $0.99	50%	50%

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We determined net income per limited partner unit as follows:

	For the three months ended June 30, 2009	2008	For the six months ended June 30, 2009	2008
	(in millions, except per share amounts)			
Net income	$ 117.5	$ 58.8	$ 186.1	$ 161.9
Less distributions paid:				
Incentive distributions to General Partner	(12.6)	(10.4)	(25.1)	(19.5)
Distributed earnings allocated to General Partner (2%)	(2.3)	(2.0)	(4.6)	(3.9)
Total distributed earnings to General Partner	(14.9)	(12.4)	(29.7)	(23.4)
Total distributed earnings to limited partners (98%)	(115.4)	(95.6)	(229.8)	(186.8)
Total distributed earnings	(130.3)	(108.0)	(259.5)	(210.2)
Distributions in excess of earnings	$ (12.8)	$ (49.2)	$ (73.4)	$ (48.3)
Weighted average limited partner units outstanding	116.1	96.3	115.6	94.4
Limited partner interests				
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit	$ 0.99[1]	$ 0.99[1]	$ 1.99[1]	$ 1.98[1]
Distributions in excess of earnings per limited partner unit	(0.11)[2]	(0.50)[2]	(0.62)[2]	(0.50)[2]
Net income per limited partner unit (basic and diluted)	$ 0.88	$ 0.49	$ 1.37	$ 1.48

(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.

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 issued check payments that have not yet been presented to the financial institution totaling approximately $20.3 million at June 30, 2009 and $30.5 million at December 31, 2008 are included in Accounts payable and other on our consolidated statements of financial position.

Bank of America, N.A., as administrative agent to our Second Amended and Restated Credit Agreement, which we refer to as the Credit Facility, previously required us to provide cash collateral for a portion of the letters of credit outstanding under the terms of our Credit Facility that would have been obligations of Lehman Brothers Bank, FSB, which we refer to as Lehman BB. The amount of cash collateral we provided was $0.1 million at December 31, 2008. On March 31, 2009, we amended our Credit Facility to remove Lehman BB which eliminated the collateral requirement imposed on us by Bank of America, N.A., as administrative agent. At June 30, 2009, no cash collateral was required and none of our cash and cash equivalents was restricted for use.

4. INVENTORY

Inventory is comprised of the following:

	June 30, 2009	December 31, 2008
	(in millions)	
Materials and supplies	$ 4.2	$ 3.9
Crude oil inventory	2.3	7.1
Natural gas and NGL inventory	50.7	42.0
	$ 57.2	$ 53.0

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The Cost of natural gas on our consolidated statements of income includes charges totaling $0.1 million and $3.4 million for the three and six month periods ended June 30, 2009, respectively, that we recorded to reduce the cost basis of our natural gas and natural gas liquids, or NGLs, inventory to reflect market value.

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	June 30, 2009	December 31, 2008
	(in millions)	
Land	$ 34.2	$ 17.9
Rights-of-way	490.8	437.1
Pipelines	5,163.1	4,327.8
Pumping equipment, buildings and tanks	1,091.7	995.4
Compressors, meters, and other operating equipment	699.2	639.3
Vehicles, office furniture and equipment	162.5	153.0
Processing and treating plants	331.2	343.1
Construction in progress	689.0	1,057.0
Total property, plant and equipment	8,661.7	7,970.6
Accumulated depreciation	(1,368.3)	(1,247.7)
Property, plant and equipment, net	$ 7,293.4	$ 6,722.9

6. DEBT

Credit Facility

On March 31, 2009, we amended our Credit Facility to remove Lehman BB as a lender, which effectively reduced the amounts available to us under our Credit Facility. The removal of Lehman BB permanently reduced both the amount we may borrow under the terms of our Credit Facility to $1,167.5 million as well as the number of committed lenders to 13. The amendment to our Credit Facility did not result in any changes to the pricing, fees or other commercial terms.

At June 30, 2009, we had $543.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.62% and outstanding letters of credit totaling $5.8 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the balance of our outstanding letters of credit.

At June 30, 2009, we could borrow $618.7 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$ 1,167.5
Less: Amounts outstanding under Credit Facility	(543.0)
Balance of letters of credit outstanding	(5.8)
Total amount we could borrow at June 30, 2009	$ 618.7

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, which typically is a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the six month periods ended June 30, 2009 and 2008, we net settled borrowings of approximately $957.1 million and $410 million, respectively, on a non-cash basis.

Senior Notes

We repaid at face value $175.0 million in principal amount of our 4.0% Senior Notes that matured on January 15, 2009.

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364-day Credit Facilities

In April 2009, we entered into two unsecured and non-guaranteed revolving credit facility agreements totaling $350 million for funding our general activities and working capital, which we refer to as the 364-day Credit Facilities. The 364-day Credit Facilities include a $200 million agreement with Barclays Bank PLC, as administrative agent, and Barclays Bank PLC and Export Development Canada as lenders, which we refer to as the Barclays Agreement, and a $150 million affiliate credit agreement, or the EUS Agreement, with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc., or Enbridge. We entered into each agreement concurrently with an initial maturity date of April 7, 2010 and a one-year extension, for a fee, exercisable at our option. Amounts we may borrow under the agreements comprising the 364-day Credit Facilities have the same terms, which are summarized below; however, amounts we borrow under the EUS Agreement are subordinate to amounts we borrow under the Barclays Agreement.

Under our 364-day Credit Facilities, borrowings can be funded through either a Fixed Period Eurodollar Rate Loan or Base Rate Loan, as those terms are defined in the agreements. Borrowings drawn under the Fixed Period Eurodollar Rate Loan bear interest at a rate per annum equal to the British Bankers Association London Interbank Rate, or BBA Libor. Under the Base Rate Loan borrowings, interest will be at a rate per annum that is equal to the greater of (a) the Federal Funds Rate plus 0.5%; (b) the prime rate as determined by Barclays Bank PLC; or (c) the Fixed Period Eurodollar Rate plus 1.0%.

Our 364-day Credit Facilities contain restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending on or before March 31, 2010 and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At June 30, 2009, our leverage ratio was approximately 4.0 as computed pursuant to the terms of our 364-day Credit Facilities. Our 364-day Credit Facilities also place limitations on the debt that our subsidiaries may incur directly. Accordingly, we are expected to provide debt financing to our subsidiaries as necessary.

Any repayments on the 364-day Credit Facilities must be made pro-rata between the Barclays Agreement and the EUS Agreement, until such time as the Barclays credit facility is repaid. At June 30, 2009, we had no amounts outstanding under our 364-day Credit Facilities and the full amount remains available for our use. Both the Barclays Agreement and EUS Agreement rank equally to our Credit Facility and senior indebtedness and superior to our current and future junior notes.

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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 Credit Facility borrowings approximate their fair values at June 30, 2009 and December 31, 2008 due to the short-term nature of these obligations. 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.

	June 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Credit Facility	$ 543.0	$ 543.0	$ 166.8	$ 166.8
9.150% First Mortgage Notes	93.0	100.0	93.0	93.8
5.358% Senior unsecured zero coupon notes due 2022	220.4	225.2	214.7	211.0
4.000% Senior Notes due 2009			175.0	175.2
7.900% Senior Notes due 2012	100.0	105.8	99.9	93.7
4.750% Senior Notes due 2013	199.9	189.6	199.9	163.4
5.350% Senior Notes due 2014	199.9	191.9	199.9	151.3
5.875% Senior Notes due 2016	299.8	293.5	299.8	234.5
7.000% Senior Notes due 2018	99.9	102.3	99.9	81.9
6.500% Senior Notes due 2018	398.1	398.3	398.0	317.7
9.875% Senior Notes due 2019	499.7	614.2	499.7	500.4
7.125% Senior Notes due 2028	99.8	96.0	99.8	72.7
5.950% Senior Notes due 2033	199.7	160.1	199.7	119.7
6.300% Senior Notes due 2034	99.8	83.1	99.8	62.3
7.500% Senior Notes due 2038	398.9	382.0	398.9	289.2
8.050% Junior subordinated notes due 2067	399.4	291.5	399.3	209.3
Total	$ 3,851.3	$ 3,776.5	$ 3,644.1	$ 2,942.9

7. PARTNERS CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C., which we refer to as Enbridge Management, during the six month period ended June 30, 2009:

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)	Amount of Distribution of Class C units to Class C unit Holders(2)	Retained from General Partner(3)	Distribution of Cash
		(in millions, except per unit amounts)						
April 30, 2009	May 7, 2009	May 15, 2009	$ 0.990	$ 129.2	$ 15.1	$ 20.1	$ 0.7	$ 93.3
January 30, 2009	February 5, 2009	February 13, 2009	0.990	128.0	14.6	19.5	0.7	93.2

(1) During 2009, in lieu of cash distributions, we issued 921,351 i-units to Enbridge Management.

(2) During 2009, in lieu of cash distributions, we issued 1,186,365 Class C units to our Class C unitholders.

(3) We retain an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner in respect of its 2 percent general partner interest.

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8. RELATED PARTY TRANSACTIONS

UTOS Disposition

In January 2009, we sold the member interests of our UTOS system for minimal consideration to Enbridge Offshore (Gas Transportation), L.L.C., a wholly-owned subsidiary of Enbridge. The UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term contracts. The UTOS system was not considered strategic to our ongoing operations, but is strategically aligned with Enbridge s offshore operations.

Purchase of Line Pipe

We, our general partner and Enbridge Pipelines Inc., which we refer to as Enbridge Pipelines, a subsidiary of Enbridge, regularly collaborate on construction projects that are mutually beneficial to our respective customers and operations. Examples of such projects include the Southern Access and Alberta Clipper projects where we have constructed and are constructing the U.S. portion of the projects and Enbridge Pipelines has constructed and is constructing the Canadian portion. In March 2009, we acquired, for $27.0 million, approximately 25 miles of 36-inch diameter line pipe from our general partner for our use in constructing the Alberta Clipper project. The line pipe was initially obtained by our general partner for use in constructing the Southern Access extension, which has been delayed due to a protracted regulatory process. This transaction was previously approved by the Enbridge Management Board of Directors.

Line 13 Exchange and Lease

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C., or Southern Lights, a wholly-owned subsidiary of our general partner, we completed the transfer of a 156-mile section of pipeline, which we refer to as Line 13, from our Lakehead system to Southern Lights in exchange for a newly constructed pipeline for transporting light sour crude oil. In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines, or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $165.2 million increase in Property, plant and equipment and the capital account of our general partner included in Partners capital on our June 30, 2009 consolidated statement of financial position, representing the $170.2 million cost of the light sour pipeline that was in excess of the $5.0 million net book value of the Line 13 assets we exchanged. Subsequent to the exchange, we incurred $4.5 million of additional costs during the three month period ended June 30, 2009. The light sour pipeline is newer and has a slightly higher capacity than Line 13, which will allow us to transport additional volumes of light sour crude oil on our Lakehead system with less integrity and maintenance costs, although depreciation and property tax expense is anticipated to increase in future periods due to the higher book value associated with these assets.

EUS Credit Facility

In April 2009, we entered into a $150 million unsecured and non-guaranteed revolving credit facility agreement with Enbridge (U.S.) Inc., as discussed in Note 6 Debt *364-day Credit Facilities.*

Purchase of Spearhead Pipeline

On May 1, 2009, we purchased a portion of a crude oil pipeline system from CCPS Transportation, L.L.C., a wholly-owned subsidiary of our general partner, for $75.0 million, representing the carrying value in the records of our general partner. The portion of the system, which we refer to as Spearhead North, includes approximately seven storage tanks and 75 miles of pipeline that our general partner reversed to provide northbound service from

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Flanagan, Illinois to Griffith, Indiana. The acquisition of Spearhead North will serve to complement our existing operations on our Lakehead system, as our newly-constructed Southern Access pipeline ends in Flanagan where it connects to Spearhead North. The transaction was previously approved by the Enbridge Management Board of Directors.

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 could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact that our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, 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, and, to date, no material environmental risks have been identified.

As of June 30, 2009 and December 31, 2008, we have recorded $5.7 million and $5.5 million, respectively, in Accounts payable and other and $2.5 million and $2.8 million, respectively, in Other long-term liabilities, 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.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

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 and fractionation margins, representing 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 variable rate debt obligations are issued. Our exposure to commodity price risk exists within our Natural Gas and Marketing 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 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. We have hedged a portion of our exposure to variability in future cash flows associated with natural gas and NGL sales and purchases and changes in interest rates on our variable rate debt through 2013 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, which we 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 use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

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In accordance with the 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 Cost of natural gas for our commodity-based derivatives and Interest expense for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

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

If a derivative financial instrument is designated and qualifies as a hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings and is adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge s change in fair market value is recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. Although we do not presently hold any derivative financial instruments designated as fair value hedges, in the past we have designated derivatives as fair value hedges of fixed rate debt in periods of high interest rates to achieve effectively lower variable rates. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in Interest expense on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have transaction types associated with our commodity and interest rate derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualified. These non-qualified 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 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.

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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 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 Collars In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options and, pursuant to the authoritative accounting guidance, do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of 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. Our natural gas contracts allow us the option of processing natural gas when it is economical and ceasing to do 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 purchases of natural gas required for processing. We will typically designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

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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. Prior to April 1, 2009, forward contracts were not treated as derivative financial instruments pursuant to the normal purchase normal sale, or NPNS, exception allowed under authoritative accounting guidance, since the forward contracts resulted in physical receipt or delivery of NGLs. However, evolving markets for NGLs have increased opportunities for a portion of our forward contracts to be settled net rather than physically receiving or delivering the NGLs. Accordingly, we have revoked the NPNS exception on certain forward contracts associated with the liquids marketing operations of Dufour Petroleum, L.P., our wholly-owned subsidiary, executed after April 1, 2009. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting and are being marked-to-market each period with the changes in fair value being recorded to earnings. As a result, our operating income will be subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.

Interest Rate Risk Exposures:

Interest Rate Caps At the corporate level, our earnings and cash flows are affected by fluctuations in interest rates associated with our variable interest rate debt. Our variable interest rate borrowing cost is determined at the time of each borrowing or interest rate reset based upon a posted LIBOR rate for the period of borrowing or interest rate reset, plus a defined credit spread. In order to mitigate the effect on our cash flows that can result in a rising interest rate environment, we have entered into interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness. Although our interest rate caps protect us from the adverse effect of higher interest rates, they do not qualify for hedge accounting and, as a result, changes in the market value of these instruments will create additional volatility in our earnings.

In all instances related to the commodity price exposures described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we employ for the derivative financial instruments we use 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 historical cost) 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.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of cost of natural gas and interest expense in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ (0.4)	$ 0.7	$ (0.6)	$ (1.2)
Non-qualified hedges	(2.6)	(22.7)	(12.4)	6.0
Marketing				
Non-qualified hedges	17.5	(22.0)	10.6	(34.9)
Commodity derivative fair value gains (losses)	14.5	(44.0)	(2.4)	(30.1)
Corporate				
Non-qualified interest rate hedges	2.4	0.2	2.4	
Derivative fair value gains (losses)	$ 16.9	$ (43.8)	$	$ (30.1)

Derivative Positions

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

	June 30, 2009	December 31, 2008
	(in millions)	
Other current assets	$ 27.5	$ 70.6
Other assets, net	36.6	75.7
Accounts payable and other	(29.0)	(40.6)
Other long-term liabilities	(58.6)	(71.0)
	$ (23.5)	$ 34.7

The changes in net assets and liabilities associated with our derivatives are primarily due to the increase in forward and daily NGL prices from December 31, 2008 to June 30, 2009. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

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 $1.3 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three and six months ended June 30, 2009, we reclassified unrealized net gains of $9.7 million and $19.8 million, respectively, from AOCI to cost of natural gas on our consolidated statements of income for the fair value of derivative financial instruments that were settled. For the three and six months ended June 30, 2008 we reclassified from AOCI to cost of natural gas on our consolidated statements of income unrealized net losses of $29.0 million and $60.3 million, respectively. We estimate that approximately $0.9 million of AOCI, representing unrealized net losses on cash flow hedging activities based on pricing and positions at June 30, 2009, will be reclassified to earnings during the next twelve months.

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

	June 30, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$	$
AA	4.3	(39.6)
A	(27.6)	73.3
Lower than A	(0.9)	(1.2)
	(24.2)	32.5
Credit valuation adjustment	0.7	2.2
Total	$ (23.5)	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure has also declined. When credit thresholds are met pursuant to the terms of our ISDA® financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. 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 or require immediate settlement of 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 each counterparty s credit rating. 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, but the agreements do not contain additional triggers or automatic termination clauses relating to credit downgrades. 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 the tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At June 30, 2009, we were in an overall net liability position of $23.5 million, which included assets of $64.1 million. Based on our forward positions at June 30, 2009, if our credit ratings were downgraded to BBB- by Standard & Poor s or Baa3 by Moody s Investors Service, we would be required to provide an additional $27.0 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements.

Counterparties to our derivative financial instruments include credit concentrations with U.S. financial institutions, international financial institutions, investment banking entities and, to a lesser extent, international integrated oil companies. At June 30, 2009, approximately $26.6 million of receivables were payable to us from U.S. financial institutions, including investment banks. We are also in net liability positions of $9.4 million and $40.7 million with integrated oil companies and non-U.S. financial institutions, respectively, representing amounts payable by us. We are holding no cash collateral on our asset exposures nor have we posted any amounts under letters of credit relating to our liability exposure pursuant to the margin thresholds in effect at June 30, 2009 under our ISDA®.

Gross derivative balances are presented below without the effects of collateral received or posted and without the effects of master netting arrangements. Our assets are adjusted for the non-performance risk of our counterparties using their credit default swap spread rates. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted based on current credit default swap spread rates on our outstanding indebtedness. 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 these schedules presented at gross values rather than the net amounts we present in our other derivative schedules, is also provided below.

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Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	June 30, 2009			
	Asset Derivatives		Liability Derivatives	
	Financial Position Location	Fair Value	Financial Position Location	Fair Value
		(in millions)		
Derivatives designated as hedging instruments under SFAS No. 133				
Interest rate contracts	Other current assets	$	Accounts payable and other	$ (0.7)
Interest rate contracts	Other assets, net	0.1	Other long-term liabilities	(13.6)
Commodity contracts	Other current assets	35.6	Accounts payable and other	(36.5)
Commodity contracts	Other assets, net	32.5	Other long-term liabilities	(53.3)
		68.2		(104.1)
Derivatives not designated as hedging instruments under SFAS No. 133				
Interest rate contracts	Other current assets	5.6	Accounts payable and other	(4.5)
Interest rate contracts	Other assets, net	7.7	Other long-term liabilities	(4.5)
Commodity contracts	Other current assets	18.7	Accounts payable and other	(19.7)
Commodity contracts	Other assets, net	19.9	Other long-term liabilities	(10.8)
		51.9		(39.5)
Total derivative instruments		$ 120.1		$ (143.6)

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

For the three months ended June 30, 2009					
Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Amount of gain (loss) recognized in AOCI on Derivative (Effective Portion)	Location of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Amount of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Location of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)*	Amount of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)*
		(in millions)			
Interest rate contracts	$ (14.2)	Interest expense	$ (1.8)	Interest expense	$
Commodity contracts	(69.0)	Cost of natural gas	9.7	Cost of natural gas	(0.4)
Total	$ (83.2)		$ 7.9		$ (0.4)

* 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.

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For the six months ended June 30, 2009

Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Amount of gain (loss) recognized in AOCI on Derivative (Effective Portion)	Location of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Amount of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Location of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)*	Amount of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)*
		(in millions)			
Interest rate contracts	$ (14.2)	Interest expense	$ (0.9)	Interest expense	$
Commodity contracts	(62.6)	Cost of natural gas	19.8	Cost of natural gas	(0.6)
Total	$ (76.8)		$ 18.9		$ (0.6)

* 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.

The amount of loss recognized in earnings represents $0.6 million related to the ineffective portion of the hedging relationships.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments under SFAS No. 133	Location of Gain or (Loss) Recognized in Earnings	For the three months ended June 30, 2009	For the six months ended June 30, 2009
		Amount of Gain or (Loss) Recognized in Earnings* (in millions)	
Interest rate contracts	Interest expense	$ 2.4	$ 2.4
Commodity contracts	Cost of natural gas	14.9	(1.8)
Total		$ 17.3	$ 0.6

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

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	June 30, 2009		
	Assets	Liabilities	Total
		(in millions)	
Fair value of derivatives gross presentation	$ 120.1	$ (143.6)	$ (23.5)
Effects of netting agreements	(56.0)	56.0	
Fair value of derivatives net presentation	$ 64.1	$ (87.6)	$ (23.5)

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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, 2009. 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, 2009				December 31, 2008			
Recurring fair value measures	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
				(in millions)				
Assets:								
Derivative instruments, net	$ 8.9	$ 13.4	$ 49.4	$ 71.7	$ 20.4	$	$ 119.6	$ 140.0
Liabilities:								
Derivative instruments, net	(61.3)	(23.4)	(10.5)	(95.2)	(77.5)		(27.8)	(105.3)
Total	$ (52.4)	$ (10.0)	$ 38.9	$ (23.5)	$ (57.1)	$	$ 91.8	$ 34.7

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities from January 1, 2009 to June 30, 2009 and from January 1, 2008 to June 30, 2008, for the respective periods. Interest rate swaps totaling $1.8 million were reclassified to Level 2 following our evaluation of the inputs used to compute fair value for these financial instruments and determination that the valuation inputs meet the qualifications for Level 2 classification.

	2009	**2008**
	(in millions)	
Beginning balance as of January 1	$ 91.8	$ (160.6)
Realized and unrealized net gains (losses)	(27.1)	49.4
Purchases		(0.9)
Transfer out of Level 3	(1.8)	
Balance as of March 31	62.9	(112.1)
Realized and unrealized net losses	(22.3)	(93.7)
Purchases	(1.7)	(1.6)
Transfer out of Level 3		
Balance as of June 30	$ 38.9	$ (207.4)
Change in unrealized net losses relating to instruments still held at June 30:		
For the three months ended June 30	$ (29.3)	$ (139.8)
For the six months ended June 30	$ (38.9)	$ (91.3)

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Fair Value Measurements of Commodity Price Derivatives

The following table provides summarized information about the fair values of our outstanding commodity derivative financial instruments at June 30, 2009 and December 31, 2008.

			At June 30, 2009				At December 31, 2008	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural Gas	12,259,562	$ 3.96	$ 6.75	$ 0.4	$ (34.5)	$ 2.5	$ (56.0)
	NGL	44,863	20.78	37.81		(2.1)		(6.5)
Receive fixed/pay variable	Natural Gas	12,490,056	5.70	4.19	21.9	(3.1)	38.7	(19.6)
	NGL	1,965,672	45.82	38.27	16.7	(1.9)	70.0	
	Crude Oil	374,728	66.62	71.92	1.2	(2.9)	5.8	(0.6)
Receive variable/pay variable	Natural Gas	68,097,561	3.93	3.91	5.5	(3.7)	8.9	(12.8)
Options								
Calls (written)	Natural Gas	184,000	4.31	4.38		(0.1)		(0.6)
Puts (purchased)	Natural Gas	184,000	4.38	3.40				(1.2)
	NGL	656,328	36.57	35.41	2.9		9.3	
	Crude Oil	128,800	71.92	64.86	0.2			
Forward Sales								
Receive variable/pay fixed	NGL	568,620	46.30	43.85	1.4			
Receive fixed/pay variable	NGL	1,021,718	46.53	48.63		(2.2)		
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	10,397,990	$ 5.69	$ 6.43	$ 2.4	$ (10.0)	$ 2.5	$ (6.5)
	NGL	200,322	49.58	46.50	3.7	(1.0)		(1.3)
Receive fixed/pay variable	Natural Gas	16,814,622	4.97	5.83	5.5	(19.9)	2.2	(27.5)
	NGL	2,615,225	46.07	42.87	19.1	(10.8)	28.0	
	Crude Oil	720,790	71.95	75.35	3.9	(6.3)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	75,292,893	5.72	5.70	2.9	(1.6)	0.8	(3.1)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.06		(0.6)		(1.0)
Puts (written)	Crude Oil	36,500	67.75	75.35		(0.2)		
Puts (purchased)	Natural Gas	365,000	6.06	3.40				
	NGL	595,680	46.04	42.85	6.0		5.2	
	Crude Oil	255,500	75.41	69.76	1.5			
Forward Sales								
Receive variable/pay fixed	NGL	10,000	36.18	28.56	0.1			
Receive fixed/pay variable	NGL	95,122	39.67	41.68		(0.2)		
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	2,944,510	$ 6.58	$ 7.20	$ 2.4	$ (4.1)	$ 2.6	$ (3.4)
	NGL	2,857	66.72	47.67	2.2			
Receive fixed/pay variable	Natural Gas	9,301,675	4.19	6.82	1.4	(25.1)	1.1	(28.1)
	NGL	581,810	55.84	42.01	9.1	(1.3)	13.0	(0.3)
	Crude Oil	621,875	71.24	78.39	1.1	(5.6)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.73	6.69	1.3	(0.6)		(1.0)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.89		(0.9)		(1.0)
Puts (purchased)	Natural Gas	365,000	6.89	3.40				
	NGL	83,220	63.34	38.41	2.3		2.7	
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	1,661,265	$ 6.85	$ 7.94	$ 0.7	$ (2.4)	$ 0.8	$ (2.1)
	NGL	36,600	38.16	55.58		(0.6)		(0.9)
Receive fixed/pay variable	Natural Gas	2,175,556	4.68	7.25	0.2	(5.5)		(5.8)
	NGL	458,232	70.56	44.05	11.3		15.7	
	Crude Oil	366,000	75.72	80.30		(1.6)	0.8	
Receive variable/pay variable	Natural Gas	1,089,000	6.84	6.48	0.4			

Options								
Puts (purchased)	NGL	128,832	66.80	41.22	3.7		4.4	
Contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	896,805	$ 6.90	$ 6.88	$ 0.1	$ (0.1)	$	$
Receive fixed/pay variable	Natural Gas	1,626,805	8.20	6.92	2.0	(0.1)	2.0	
	Crude Oil	292,000	86.41	81.88	2.7	(1.5)	3.4	

(1) Volumes of Natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and Crude are measured in barrels, or Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at June 30, 2009 and December 31, 2008, 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.

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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.

	Notional Principal (dollars in millions)	Partnership Pays	Partnership Receives	Maturity Date	Fair Value June 30, 2009 (dollars in millions)	Fair Value December 31, 2008 (dollars in millions)
Interest Rate Swaps						
Floating to Fixed:						
	$ 50.0	4.6175%	LIBOR[2]	January 15, 2009	$	$
	$ 50.0	4.6130%	LIBOR	January 29, 2009		
	$ 50.0	4.6525%	LIBOR	February 13, 2009		(0.1)
	$ 50.0	4.5875%	LIBOR	February 20, 2009		(0.2)
	$ 50.0	1.6510%	LIBOR	December 2, 2010	(0.1)	
	$ 50.0	1.6570%	LIBOR	December 5, 2010	(0.1)	
	$ 50.0	1.6870%	LIBOR	December 12, 2010	(0.1)	
	$ 50.0	1.7040%	LIBOR	December 14, 2010	(0.1)	
	$ 50.0	1.7180%	LIBOR	December 18, 2010	(0.1)	
	$ 50.0	4.3700%	LIBOR-21 bps[1]	June 1, 2013	(3.7)	(5.3)
	$ 50.0	4.3425%	LIBOR-21 bps	June 1, 2013	(3.6)	(5.2)
	$ 25.0	4.3100%	LIBOR-25 bps	June 1, 2013	(1.8)	(2.7)
	$ 50.0	4.1160%	LIBOR	December 2, 2013	(0.7)	
	$ 50.0	4.1250%	LIBOR	December 4, 2013	(0.7)	
	$ 50.0	4.1320%	LIBOR	December 8, 2013	(0.7)	
	$ 50.0	4.1270%	LIBOR	December 10, 2013	(0.7)	
	$ 50.0	4.1570%	LIBOR	December 12, 2013	(0.7)	
	$ 50.0	4.1720%	LIBOR	December 14, 2013	(0.7)	
	$ 75.0	4.1380%	LIBOR	December 15, 2013	(1.0)	
	$ 50.0	4.1740%	LIBOR	December 18, 2013	(0.7)	
	$ 50.0	4.1920%	LIBOR	December 22, 2013	(0.7)	
	$ 125.0	4.1680%	LIBOR	December 31, 2013	(1.8)	
Fixed to Floating:						
	$ 25.0	LIBOR-25bps	4.7500%	June 1, 2013	2.2	3.1
	$ 50.0	LIBOR-21bps	4.7500%	June 1, 2013	4.4	6.1
	$ 50.0	LIBOR-21bps	4.7500%	June 1, 2013	4.4	6.1
Treasury Locks:						
	$ 20.0	4.6230%	LIBOR	June 30, 2020	(0.5)	
	$ 200.0	4.6190%	LIBOR	June 30, 2020	(5.0)	
Interest Rate Caps:						
	$ 25.0	1.0900%	N/A	December 17, 2010	0.1	
	$ 50.0	1.1500%	N/A	December 22, 2010	0.3	
	$ 125.0	1.0700%	N/A	December 31, 2010	0.8	
	$ 50.0	1.1450%	N/A	January 4, 2011	0.3	
	$ 25.0	1.1500%	N/A	January 8, 2011	0.2	
	$ 50.0	1.1150%	N/A	January 10, 2011	0.3	
	$ 75.0	1.1500%	N/A	January 15, 2011	0.5	

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

(2) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

11. 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 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 financial information about our business segments:

	For the three months ended June 30, 2009				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[(1)]	Total
Total revenue	$ 228.4	$ 889.4	$ 503.9	$	$ 1,621.7
Less: Intersegment revenue		306.5	5.0		311.5
Operating revenue	228.4	582.9	498.9		1,310.2
Cost of natural gas		421.9	473.1		895.0
Operating and administrative	59.2	76.0	1.7	1.2	138.1
Power	29.8				29.8
Depreciation and amortization	34.6	35.1	0.4		70.1
Operating income	104.8	49.9	23.7	(1.2)	177.2
Interest expense				57.9	57.9
Other income				0.3	0.3
Income before income tax expense	104.8	49.9	23.7	(58.8)	119.6
Income tax expense				2.1	2.1
Net income	$ 104.8	$ 49.9	$ 23.7	$ (60.9)	$ 117.5
Capital expenditures (excluding acquisitions)	$ 295.8	$ 30.4	$	$ 4.8	$ 331.0

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

	For the three months ended June 30, 2008				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[(1)]	Total
Total revenue	$ 189.2	$ 2,280.7	$ 1,474.2	$	$ 3,944.1
Less: Intersegment revenue	0.2	944.3	67.4		1,011.9
Operating revenue	189.0	1,336.4	1,406.8		2,932.2
Cost of natural gas		1,192.6	1,421.7		2,614.3
Operating and administrative	41.3	77.1	2.3	1.1	121.8

Power	31.3				31.3
Depreciation and amortization	26.7	28.2	0.4		55.3
Operating income	89.7	38.5	(17.6)	(1.1)	109.5
Interest expense				51.4	51.4
Other income				2.5	2.5
Income before income tax expense	89.7	38.5	(17.6)	(50.0)	60.6
Income tax expense				1.8	1.8
Net income	$ 89.7	$ 38.5	$ (17.6)	$ (51.8)	$ 58.8
Capital expenditures (excluding acquisitions)	$ 204.9	$ 90.4	$	$ 3.3	$ 298.6

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

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	As of and for the six months ended June 30, 2009				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 448.1	$ 1,883.8	$ 1,153.2	$	$ 3,485.1
Less: Intersegment revenue	0.3	698.8	16.1		715.2
Operating revenue	447.8	1,185.0	1,137.1		2,769.9
Cost of natural gas		891.9	1,105.2		1,997.1
Operating and administrative	113.6	156.6	3.5	2.1	275.8
Power	63.2				63.2
Depreciation and amortization	64.0	69.4	0.8		134.2
Operating income	207.0	67.1	27.6	(2.1)	299.6
Interest expense				109.2	109.2
Other expense				0.2	0.2
Income before income tax expense	207.0	67.1	27.6	(111.5)	190.2
Income tax expense				4.1	4.1
Net income	$ 207.0	$ 67.1	$ 27.6	$ (115.6)	$ 186.1
Total assets	$ 4,512.1	$ 3,527.8	$ 207.2	$ 228.9	$ 8,476.0
Capital expenditures (excluding acquisitions)	$ 458.3	$ 77.4	$	$ 8.2	$ 543.9

[1] Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

	As of and for the six months ended June 30, 2008				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 346.2	$ 4,154.8	$ 2,673.0	$	$ 7,174.0
Less: Intersegment revenue	0.2	1,654.4	151.9		1,806.5
Operating revenue	346.0	2,500.4	2,521.1		5,367.5
Cost of natural gas		2,180.4	2,532.7		4,713.1
Operating and administrative	78.8	152.0	4.6	3.1	238.5
Power	69.6				69.6
Depreciation and amortization	46.3	57.3	0.9		104.5
Operating income	151.3	110.7	(17.1)	(3.1)	241.8
Interest expense				79.0	79.0
Other income				2.2	2.2
Income before income tax expense	151.3	110.7	(17.1)	(79.9)	165.0
Income tax expense				3.1	3.1
Net income	$ 151.3	$ 110.7	$ (17.1)	$ (83.0)	$ 161.9
Total assets	$ 3,460.5	$ 3,652.4	$ 549.5	$ 224.7	$ 7,887.1
Capital expenditures (excluding acquisitions)	$ 501.7	$ 163.9	$	$ 6.5	$ 672.1

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

12. UNRECORDED REVENUES

Enbridge Energy, Limited Partnership, also referred to as the Enbridge Partnership, our wholly-owned subsidiary, was party to a joint tariff agreement with Mustang Pipe Line, LLC, or Mustang, a business partially-owned by Enbridge (30%) and a major integrated oil company (70%). Mustang receives crude oil from the

Enbridge Partnership system in the Chicago, Illinois market area. Crude oil delivered to Mustang is then transported on its pipeline system to markets south of Chicago. The joint tariff agreement that was in place with Mustang allowed for shippers on our Lakehead system to reach markets downstream of Chicago through a discounted transportation rate for their commitments to transport crude oil on our Lakehead system and then on the Mustang pipeline. Since October 2005, a shipper on our Lakehead system, which was not a committed shipper, was incorrectly invoiced at the discounted transportation rate. Additionally, we continued to invoice two shippers whose commitments expired in September 2008 at discounted transportation rates rather than the undiscounted non-committed shipper rates. As a result of invoicing these shippers at the discounted rate rather than the undiscounted rate, we under-recorded approximately $13.8 million of operating revenues on our Lakehead system from October 2005 through December 2008. The unrecorded revenues, which we recorded in the first quarter of 2009 and subsequently collected, were not material to prior financial statement periods and we have included the entire $13.8 million in our consolidated statement of income for the six months ended June 30, 2009.

13. REGULATORY ACCOUNTING

Certain of our liquids and natural gas activities are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers. The rates we are allowed to charge shippers associated with our Southern Access expansion project include an allowance that provides a rate of return to our partners. For rate-making purposes, we have capitalized approximately $102.0 million that we have not reflected on our consolidated statements of financial position at June 30, 2009.

14. SUBSEQUENT EVENTS

We have evaluated events subsequent to June 30, 2009 through July 27, 2009, the date we issued these financial statements, and identified the events disclosed below.

Zero Coupon Senior Note Repayment

On July 21, 2009, we received notice that the holders of our senior, unsecured zero coupon notes due on August 28, 2022, referred to as the Zero Coupon Notes, have elected to exercise the call feature of the notes that require early repayment of the debt. We will be required to be repay the Zero Coupon Notes on August 28, 2009 at an amount of approximately $222.3 million, representing the principal amount of the Zero Coupon Notes on the repayment date. The carrying amount of our Zero Coupon Notes is currently included in Current maturities of long-term debt on our consolidated statement of financial position.

Joint Funding Arrangement for Alberta Clipper Project

In July 2009 we announced a joint funding arrangement with our general partner and other affiliates of ours and Enbridge to participate in financing construction of the United States portion of our $1.2 billion Alberta Clipper project being constructed by the Enbridge Partnership. Enbridge, through our general partner, will fund two-thirds of the debt financing for the project and two-thirds of the project s equity requirements directly into the Enbridge Partnership. We will fund one-third of the debt and equity financing required for the project. Enbridge, through our general partner, will be entitled to two-thirds of the earnings and cash flows that the Enbridge Partnership generates from the project. We will be entitled to one-third of the project s earnings and cash flows. We and our general partner each have a right of first refusal on the other s investment in the project and we will retain the right to fund up to 100 percent of any expansion of the project, which would result in a corresponding adjustment to our general partner s interest. Promptly following the in-service date for the project, we must use commercially reasonable efforts to issue debt in one or more capital market transactions, the proceeds of which would be used to refinance the loan we make to the Enbridge Partnership under the funding arrangement, on substantially the same terms as the debt issued in the capital market transaction. On the same date, our general partner will refinance its loans with respect to the project on the same terms as our refinanced loan to the Enbridge Partnership.

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Distribution to Partners

On July 24, 2009, the Board of Directors of Enbridge Management declared a distribution payable to our partners on August 14, 2009. The distribution will be paid to unitholders of record as of August 6, 2009, of our available cash of $130.3 million at June 30, 2009, or $0.990 per common unit. Of this distribution, $93.4 million will be paid in cash, $15.5 million will be distributed in i-units to our i-unitholder, $20.7 million will be distributed in Class C units to the holders of our Class C units and $0.7 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

FERC Transportation Tariffs-Liquids

Effective July 1, 2009, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, and does not apply to the SEP II, Terrace and Facilities surcharges, which includes Southern Access. Effective July 2009, we increased the base tariff rates on our Lakehead system by an average of 7.6 percent to equal the indexed ceiling level allowed under the FERC s indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is $1.46 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2009. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 7.6 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology. We anticipate the rate increase will contribute approximately $33 million to our operating revenues over the next twelve months.

15. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

FASB Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board, or FASB, approved the FASB Accounting Standards Codification™, which we refer to as the FASB ASC, or codification, as the single source of authoritative, nongovernmental Generally Accepted Accounting Principles, or GAAP. The FASB ASC reorganizes all of the pronouncements under GAAP and displays them in approximately 90 accounting topics. The reorganization and codification of GAAP was initiated by the FASB in an effort to:

- Reduce the amount of time and effort required to solve an accounting research issue.
- Mitigate the risk of noncompliance with standards through improved usability of the literature.
- Provide accurate information with real-time updates as new standards are released.
- Assist FASB with the research and convergence efforts required during the standard setting process.
- Become the authoritative source of literature for the completed XBRL taxonomy.

Included in the codification are relevant portions of authoritative content issued by the Securities and Exchange Commission, or SEC, as well as selected SEC staff interpretations and administrative guidance. The FASB ASC will be effective for both interim and annual reporting periods ending after September 15, 2009. We do not expect our adoption of the codification in the third quarter of 2009 to have a significant effect on our financial statements.

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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 should be read together with our consolidated financial statements and the accompanying notes included in Item 1. Financial Statements of this report.

Additionally, this quarterly report on Form 10-Q should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2008.

IMPACT OF CURRENT ECONOMIC CONDITIONS

The recession that began in late 2007 has continued to curtail the availability of capital in the United States during the three and six months ended June 30, 2009. As a result, our ability to raise funds through issuances of debt and equity at prices that are similar to offerings in recent years continues to be limited and is expected to remain so as long as the capital markets remain constrained. We have taken several tangible steps to enhance our liquidity position since the end of 2008. First, we continue to limit our capital expenditure activities to those projects strategic to us. We have also put in place bridge liquidity in the form of our $350 million 364-day Credit Facilities, as discussed below. Most significantly, we recently announced a joint funding arrangement for our Alberta Clipper project through which our general partner and other affiliates of ours and Enbridge Inc., or Enbridge, will participate jointly in financing the United States portion of the construction project, which will substantially reduce our need to raise equity over the next 12 to 18 months. Following our announcement, both Standard & Poor s Ratings Services and Moody s Investors Service revised their ratings outlook on our senior unsecured debt to stable from negative. Standard & Poor s also raised our short-term rating to A-2 from A-3, which will allow us to once again access the commercial paper market.

Our efforts are intended to maintain sufficient liquidity to fund our remaining growth programs and sustain the present distribution rate to our unitholders, while preserving our credit rating. Maintaining adequate liquidity may also involve the issuance of debt and equity at less attractive terms than our most recent offerings and could involve the sale of non-core assets, further asset partnership or joint venture arrangements or other strategies to limit the amount of external funding required for our growth projects.

RESULTS OF OPERATIONS OVERVIEW

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

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

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

The following table reflects our operating income by business segment and corporate charges for the three and six month periods ended June 30, 2009 and 2008.

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating Income				
Liquids	$ 104.8	$ 89.7	$ 207.0	$ 151.3
Natural Gas	49.9	38.5	67.1	110.7
Marketing	23.7	(17.6)	27.6	(17.1)
Corporate, operating and administrative	(1.2)	(1.1)	(2.1)	(3.1)
Total Operating Income	177.2	109.5	299.6	241.8
Interest expense	57.9	51.4	109.2	79.0
Other income (expense)	0.3	2.5	(0.2)	2.2
Income tax expense	2.1	1.8	4.1	3.1
Net Income	$ 117.5	$ 58.8	$ 186.1	$ 161.9

Contractual arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be very significant as evidenced by commodity prices during 2008. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The operating income of our Liquids segment for the three and six month periods ended June 30, 2009 compared to the same periods in 2008 was affected by the following:

- Transportation rate increases that went into effect July 2008 and in January and April 2009, which include increases in our tolls associated with the annual index rate ceiling adjustments, additional facilities added, and a true-up of prior year surcharges;

- Completion and start-up of the second stage of our Southern Access Expansion and the Phase V expansion of our North Dakota system

- Higher delivered volumes on our Lakehead system; and

- Additional spot storage fee revenue generated by our Mid-Continent storage terminal system.

The above increases to operating income were partially offset by:

Lower prices associated with the allowance oil we receive coupled with less favorable oil measurement adjustments; and

Increased operating costs and depreciation associated with the additional assets we have placed into service.

Natural Gas

The following factors affected the operating income of our Natural Gas business for the three month period ended June 30, 2009 compared to the same period of 2008:

$3.0 million of unrealized, non-cash mark-to-market losses from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of $22.0 million for the same period of 2008;

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- Lower margins resulting from a less favorable pricing environment for natural gas and NGLs as compared with the same period of 2008;

- Growth in transportation volumes associated with the completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project;

- Benefits yielded from our continued efforts to reduce measurement losses; and

- Overall improvement in operating and administrative costs as a result of our cost reduction measures offset by increased work-force and depreciation costs associated with our completed expansion projects.

For the six month period ended June 30, 2009, in addition to the factors discussed above, we had $13.0 million of unrealized, non-cash mark-to-market losses compared with $4.8 million of gains we experienced in the same period of 2008.

Marketing

The operating results of our Marketing segment for the three and six month periods ended June 30, 2009 were positively affected by unrealized, non-cash, mark-to-market net gains of $17.5 million and $10.6 million, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The non-cash, mark-to-market net gains during the three and six months ended June 30, 2009 resulted from narrower transportation differentials and the settlement of derivatives associated with our park and loan activities. Additionally, our Marketing business continues to benefit from improved access to downstream natural gas pipelines provided by the natural gas system expansions and initiatives we completed in 2008, namely the Clarity project, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

For the three and six month periods ended June 30, 2008, our Marketing business was negatively impacted by unrealized, non-cash, mark-to-market losses of $22.0 million and $34.9 million, respectively, which resulted from wider transportation differentials associated with the increases in the forward and daily market prices of natural gas from March 31, 2008 and December 31, 2007, respectively.

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 interest rates and commodity prices, and minimize 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 interest rates or commodity prices. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period.

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The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of Cost of natural gas or Interest expense in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the three months ended June 30, 2009	For the three months ended June 30, 2008	For the six months ended June 30, 2009	For the six months ended June 30, 2008
	(unaudited; in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ (0.4)	$ 0.7	$ (0.6)	$ (1.2)
Non-qualified hedges	(2.6)	(22.7)	(12.4)	6.0
Marketing				
Non-qualified hedges	17.5	(22.0)	10.6	(34.9)
Commodity derivative fair value gains (losses)	14.5	(44.0)	(2.4)	(30.1)
Corporate				
Non-qualified interest rate hedges	2.4	0.2	2.4	
Derivative fair value gains (losses)	$ 16.9	$ (43.8)	$	$ (30.1)

RESULTS OF OPERATIONS BY SEGMENT

Liquids

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

	For the three months ended June 30, 2009	For the three months ended June 30, 2008	For the six months ended June 30, 2009	For the six months ended June 30, 2008
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 228.4	$ 189.0	$ 447.8	$ 346.0
Operating and administrative	59.2	41.3	113.6	78.8
Power	29.8	31.3	63.2	69.6
Depreciation and amortization	34.6	26.7	64.0	46.3
Operating expenses	123.6	99.3	240.8	194.7
Operating Income	$ 104.8	$ 89.7	$ 207.0	$ 151.3
Operating Statistics				
Lakehead system:				
United States[(1)]	1,270	1,235	1,267	1,246
Province of Ontario[(1)]	336	322	345	351
Total Lakehead system deliveries[(1)]	1,606	1,557	1,612	1,597
Barrel miles (billions)	102	103	207	212
Average haul (miles)	698	728	709	728

Mid-Continent system deliveries[1]	238	237	239	244
North Dakota system:				
Trunkline	109	107	109	105
Gathering	6	6	6	5
Total North Dakota system deliveries[1]	115	113	115	110
Total Liquids Segment Delivery Volumes[1]	1,959	1,907	1,966	1,951

(1) Average barrels per day, or Bpd in thousands.

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Three months ended June 30, 2009 compared with three months ended June 30, 2008

Our Liquids segment accounted for $104.8 million of operating income during the three months ended June 30, 2009, an increase of $15.1 million from the $89.7 million generated during the same period in 2008. The favorable results are primarily attributable to transportation rate increases that went into effect during 2008 and 2009, partially offset by higher operating and administrative costs, and depreciation.

Operating revenue for the three months ended June 30, 2009 increased by $39.4 million to $228.4 million from $189.0 million for the same period in 2008. The increase in operating revenue is due to the following:

- Increased average rates for transportation on all of our major systems as noted below;
- Higher delivered volumes on our Lakehead system; and
- Additional storage fee revenue generated by our Mid-Continent storage terminal system.

These increases in operating revenue were partially offset by lower prices associated with the allowance oil we receive in connection with our transportation services.

Increases in average transportation rates on all three Liquids systems contributed approximately $40.2 million of additional operating revenue.

- Effective July 1, 2008, we increased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment;
- Effective January 1, 2009, we increased the rates for transportation on our North Dakota system to include an updated calculation of the two surcharges related to the Phase V Expansion program; and
- Effective April 1, 2009, we increased the rates for transportation on our Lakehead system in connection with the completion of Stage 2 of our Southern Access Expansion. We also increased the transportation rates on our Lakehead system for additional facilities we added on which we receive a cost of service return and a true-up for costs associated with our Southern Access Stage 1 project.

We expect our transportation revenues to grow over the rest of 2009 due to the annual index rate ceiling adjustment that became effective July 1, 2009, which increased the average transportation rates on all three of our Liquids systems. Additional discussion of these tariffs is provided below under the section labeled *Regulatory Matters FERC Transportation Tariffs Liquids*.

Average delivery volumes on our Lakehead system increased approximately three percent, to 1.606 million Bpd for the three months ended June 30, 2009 from 1.557 million Bpd during the same period in 2008, contributing $4.4 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily due to increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands.

Also contributing to the increase in revenues for the three months ended June 30, 2009, was an approximately $3.0 million increase in storage fees generated by our Mid-Continent system due to wider storage spreads in the market coupled with variable capacity.

Our transportation tariffs allow our pipelines to deduct an allowance from our customers for the transportation of their crude oil. We recognize revenue for this allowance at the prevailing market price for crude oil. The average prices of crude oil during the three months ended June 30, 2009 are substantially lower than the average prices for the same period of 2008. For example, the average daily price of West Texas Intermediate crude oil has decreased approximately 52 percent for the three months ended June 30, 2009 as compared with the same period in 2008. As a result of the decrease in crude oil prices, we have experienced an approximate $8.1 million decrease in allowance oil revenues.

Operating and administrative expenses for the Liquids segment increased $17.9 million for the three months ended June 30, 2009, compared with the same period in 2008. The increase in these costs is primarily attributable to the following:

- Increased workforce related costs associated with the operational, administrative, regulatory, and compliance support necessary for our expansion projects;

Less favorable oil measurement adjustments as described below, primarily attributable to physical and revaluation adjustments;

Higher operating costs associated with our lease of Line 13 from an affiliate of our general partner which contributed $5.4 million to our costs. We are recovering the cost through a tolling surcharge on our Lakehead system with the net effect on our cash flow expected to approximate zero.

Oil measurement adjustments occur as part of the normal operations associated with our Liquids systems and contributed approximately $9.0 million to the increase in our operating expenses for the three months ended June 30, 2009, as compared to the same period in 2008. Our oil measurement expense level, while less than favorable than 2008, is well within accepted industry experience. The three types of oil measurement adjustments that normally occur on our systems include:

Physical, which results from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;

Degradation, which results from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil; and

Revaluation, which is a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Power costs decreased $1.5 million in the three months ended June 30, 2009, compared with the same period in 2008, predominantly due to lower utility rates we are charged by our power suppliers. The decrease in utility rates was a direct result of lower prices for natural gas and coal that are used to produce electricity.

The increase in depreciation expense of $7.9 million is attributable to the additional assets we have placed in service during the last two quarters of 2008 and first half of 2009, primarily the second stage of the Southern Access Expansion assets which we placed in service on April 1, 2009.

Six months ended June 30, 2009 compared with six months ended June 30, 2008

Our liquids segment accounted for $207.0 million of operating income during the six months ended June 30, 2009, representing a $55.7 million increase over the $151.3 million for the same period in 2008. The components comprising our operating income changed during the six months ended June 30, 2009 compared with the six months ended June 30, 2008, primarily for the same reasons as noted above in our three-month analysis. However, our operating revenues for the six months ended June 30, 2009 include approximately $13.8 million of previously unbilled operating revenues on our Lakehead system that resulted from incorrectly invoicing shippers from October 2005 through December 2008 that we recorded in March 2009.

Other Matters

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C., or Southern Lights, a wholly-owned subsidiary of our general partner, we completed the transfer of a 156-mile section of pipeline, which we refer to as Line 13, from our Lakehead system to Southern Lights, in exchange for a newly constructed pipeline for transporting light sour crude oil. In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines, or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would only be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $165.2 million increase in Property, plant and equipment and the capital account of our general partner included in Partners capital on our June 30, 2009 consolidated statement of financial position, representing the $170.2 million cost of the light sour pipeline that was in excess of the $5.0 million net book value of the Line 13 assets we exchanged. Subsequent to the exchange, we incurred $4.5 million of additional costs during the three month period ended June 30, 2009. The light sour pipeline is newer and has a slightly higher capacity than Line 13, which will allow us to transport additional volumes of light sour crude oil on our Lakehead system with less integrity and maintenance costs, although depreciation and property tax expense is anticipated to increase in future periods due to the higher book value associated with these assets.

Future Prospects Update for Liquids

We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States. The following discussion provides an update to the status of projects that we and Enbridge are developing and should be read in conjunction with the information included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2008.

Partnership Projects

Southern Access

We completed the second and final stage of our Southern Access expansion project and placed it into service on April 1, 2009. The related tolling surcharge has been adjusted to include costs of this phase of the expansion and became effective April 1, 2009. We will begin to realize revenues in connection with this increased surcharge as crude oil is delivered from our pipeline, generally the month following the effective date of the tariff. This stage provides additional upstream pumping capacity and a new pipeline from Delavan, Wisconsin to Flanagan, Illinois. Completion of the total Southern Access expansion project created a 42-inch, 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system, which can be further expanded to 1.2 million Bpd with expenditures for additional pumping equipment. The commercial structure for this expansion is a cost-of-service based surcharge that has been added to the existing transportation rates. We anticipate that earnings before interest, taxes, depreciation, and amortization, or EBITDA, associated with this project will be approximately $230 million to $250 million annually in the first full year that both stages of the Southern Access project are fully operational.

Alberta Clipper

The Alberta Clipper project involves construction of a new 36-inch diameter, 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior, Wisconsin, generally within or adjacent to our and Enbridge s existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior, a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pump stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the U.S. segment of the project will approximate $1.2 billion. Alberta Clipper will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. We and Enbridge are progressing with the project, which is expected to be in service by mid-2010. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. We anticipate financing the $1.2 billion of expected construction costs for the United States portion of the project through our recently announced joint funding arrangement through which our general partner and other affiliates of ours and Enbridge will participate jointly in financing a portion of the construction project in return for a two-thirds interest in the earnings and cash flows. The joint funding arrangement also contemplates our issuance of additional term debt in one or more capital markets transactions, following the in-service date of the project, to refinance our initial debt financing of the project. Our general partner will

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refinance its portion of its initial debt financing of the project on the same terms. We anticipate that the first full year EBITDA resulting from the completion of this project will approximate $170 million.

North Dakota

We have commenced an approximate $0.15 billion additional expansion consisting of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents, or DRA, that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. The proposed tolling methodology is similar to the structure being used on the recently completed Phase V expansion project and was approved by the Federal Energy Regulatory Commission, also referred to as the FERC, in October 2008. All necessary permits and approvals have been received and the Phase VI expansion is expected to be in service in early 2010.

Enbridge Market Access

Enbridge continues to pursue new opportunities to provide broader market access for Canadian bitumen and synthetic crudes. In addition to the planned construction of the Southern Access Extension which is expected to provide access to the Patoka market and the recently completed expansion of the Spearhead Pipeline, other key opportunities being pursued include:

- Eastern PADD II access into the Michigan and Ohio markets;
- Access to the U.S. Gulf Coast refining centers through a combination of smaller incremental opportunities and large volumes solutions; and
- PADD I access into the East Coast market near Philadelphia, Pennsylvania.

Spearhead Pipeline

The Spearhead pipeline has operated at or near its capacity of 125,000 Bpd since it was acquired and reversed by Enbridge. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 193,300 Bpd, with binding commitments for capacity of 30,000 Bpd. In December 2007, the FERC issued a favorable declaratory order effectively approving the tolling methodology and priority service for shippers with binding commitments. Construction on the 68,300 Bpd expansion was completed on schedule in early 2009 and was placed into service in May 2009. The Spearhead pipeline is complementary to our Lakehead system as western Canadian crude oil is carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline.

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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 per day, or MMBtu/d, for the periods presented:

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating revenues	$ 582.9	$ 1,336.4	$ 1,185.0	$ 2,500.4
Cost of natural gas	421.9	1,192.6	891.9	2,180.4
Operating and administrative	76.0	77.1	156.6	152.0
Depreciation and amortization	35.1	28.2	69.4	57.3
Operating expenses	533.0	1,297.9	1,117.9	2,389.7
Operating Income	$ 49.9	$ 38.5	$ 67.1	$ 110.7
Operating Statistics (MMBtu/d)				
East Texas	1,567,000	1,454,000	1,599,000	1,425,000
Anadarko	594,000	647,000	596,000	631,000
North Texas	388,000	392,000	398,000	380,000
MidLa	74,000	91,000	87,000	108,000
AlaTenn	30,000	33,000	41,000	48,000
Bamagas	93,000	36,000	117,000	69,000
Other major intrastates(1)	321,000	289,000	316,000	286,000
Total(2)	3,067,000	2,942,000	3,154,000	2,947,000

(1) We have included in the table above average daily volumes of 98,000 MMBtu/d and 75,000 MMBtu/d related to our Quivira system for the three month periods ended June 30, 2009 and 2008, respectively, and 102,000 MMBtu/d and 65,000 MMBtu/d for the six month periods ended June 30, 2009 and 2008, respectively.

(2) In January 2009, we sold the member interests of our UTOS asset, which contributed average daily volumes of approximately 178,000 MMBtu/d and 187,000 MMBtu/d for the three and six months ended June 30, 2008 and have been excluded.

Three months ended June 30, 2009 compared with the three months ended June 30, 2008

Our Natural Gas segment contributed $49.9 million of operating income for the three months ended June 30, 2009, an increase of $11.4 million from the $38.5 million contributed in the corresponding period of 2008. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the three months ended June 30, 2009 as compared with the same period of 2008:

$3.0 million of unrealized, non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of $22.0 million for the same period of 2008;

The overall decline in prices for NGLs, natural gas and condensate reduced the economic value of these commodities which we receive in-kind as payment for our services under some of our contract structures;

- Growth in transportation volumes associated with the completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project; and

- Decreased operating and administrative costs associated with our cost reduction efforts, offset by increased work-force and depreciation costs associated with our system growth projects.

Higher average forward and daily NGL prices at June 30, 2009 relative to March 31, 2009, produced unrealized, non-cash, mark-to-market net losses of $3.0 million for the three months ended June 30, 2009 from the derivatives we use to hedge the sales prices of a portion of the NGLs we derive from processing natural gas. The average forward and daily prices for natural gas were relatively stable at June 30, 2009 in relation to prices at March 31, 2009. Comparatively, at June 30, 2008 the average forward and daily prices for both natural gas and NGLs were higher than the prices at March 31, 2008, which produced $22.0 million of unrealized, non-cash, mark-to-market net losses for the derivative instruments we used to fix the price of the natural gas purchased for processing and for the derivatives we used to hedge the sales prices of a portion of the NGLs derived from processing natural gas.

The following table depicts the effect that unrealized, non-cash, mark-to-market gains and losses had on the operating results of our Natural Gas segment for the three and six months ended June 30, 2009 and 2008:

	For the three months ended June 30,		For the six months ended June 30,	
Derivative fair value gains (losses)	**2009**	**2008**	**2009**	**2008**
		(unaudited; in millions)		
Natural Gas segment				
Hedge ineffectiveness	$ (0.4)	$ 0.7	$ (0.6)	$ (1.2)
Non-qualified hedges	(2.6)	(22.7)	(12.4)	6.0
Derivative fair value gains (losses)	$ (3.0)	$ (22.0)	$ (13.0)	$ 4.8

We are exposed to fluctuations in commodity prices in the near term on approximately 10 to 25 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our margins generally increase when the prices of these commodities are rising and generally decrease when the prices are declining. During both the three months ended June 30, 2009 and 2008, NGL and condensate prices increased, while natural gas prices were relatively stable during the three months ended June 30, 2009 and increased during the same period in 2008. The commodity price environment that existed for both the three months ended June 30, 2009 and 2008, was favorable for the processing of NGLs and condensate. However, due to the overall decline in commodity prices from June 30, 2008 to June 30, 2009, the economic value of the volumes of NGLs we received from processing the natural gas was significantly lower as compared with the volumes for the same period of 2008.

The general increase in average daily volume of our Natural Gas business is directly attributable to the significant investments we have made to expand the capacity and service capability of our systems, namely the Clarity project. With the expansions we are able to provide additional gathering, processing, treating and transportation services for the customers on our East Texas system.

Our volumes and revenues are also the result of wellhead supply contracts and drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale and Granite Wash areas. During the three months ended June 30, 2009, natural gas production decreased relative to the same period in 2008. Due to the significant decline in natural gas prices over the past several months, producers have slowed down drilling activity levels compared to 2008. The number of approved drilling permits for the three months ended June 30, 2009 has declined 59% from the same period in 2008, an indicator of the producer s reluctance to engage in new drilling activities and production. Existing active drilling rigs in the areas we serve have also declined 58% during the three months ended June 30, 2009 from levels that existed in the corresponding period in 2008. Our margin growth may be tempered since our customers and certain of our assets may experience volume declines relative to 2008. Weak demand together with low commodity prices may lead to the inability or unwillingness of natural gas producers to commit the necessary capital to engage in new projects, which could decrease the amount of new natural gas production in the areas we serve. A decrease in new natural gas production has the potential to adversely affect the margins we derive from our Natural Gas business.

A variable element of our Natural Gas segment s operating income is derived from processing natural gas under keep-whole arrangements on our East Texas, North Texas and Anadarko systems. Operating income derived from keep-whole processing arrangements for the three months ended June 30, 2009 was $16.3 million, representing a decrease of $1.7 million, or nine percent, from the $18.0 million we produced for the same period in 2008. Although operating income derived from our keep-whole processing arrangements experienced a decline for the three months ended June 30, 2009 when compared to the same period in 2008; our keep-whole processing margin increased 37% from the margin contributed in the first three-month period of 2009. The significant increase was due largely in part to the favorable processing environment that existed as natural gas prices remained relatively stable relative to increases in the prices of NGLs and condensate in three months ended June 30, 2009 when compared to the first quarter of 2009.

Operating and administrative costs of our Natural Gas segment were $1.1 million lower for the three months ended June 30, 2009 compared to the same period in 2008, primarily due to the implementation of enhanced cost reduction measures. Our efforts to monitor costs have yielded positive results by reducing the costs associated with material and supplies and other outside services when compared to the three month period ended June 30, 2008. Although overall operating and administrative costs declined, our Natural Gas segment was affected by slight increases in both workforce-related and outside contract labor costs associated with our larger systems. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount.

Depreciation expense for our Natural Gas segment was higher for the three months ended June 30, 2009 as compared to the same period in 2008, as a result of the capital projects completed and placed into service in the last half of 2008.

Six months ended June 30, 2009 compared with six months ended June 30, 2008

Our Natural Gas segment accounted for $67.1 million of operating income during the six months ended June 30, 2009, representing a $43.6 million decrease from the $110.7 million for the same period in 2008. Some of the components comprising our operating income changed unfavorably during the six months ended June 30, 2009 compared with the six months ended June 30, 2008, which are described below.

The average forward and daily prices for natural gas at December 31, 2008 were higher relative to natural gas prices at June 30, 2009, resulting in unrealized, non-cash, mark-to-market net losses of $13.0 million for the six months ended June 30, 2009 from the derivative instruments we use to fix the price of the natural gas we purchase for processing. These net losses were compounded by unrealized, non-cash, mark-to-market net losses associated with the derivatives we use to fix the sales price of NGLs we derive from processing natural gas that resulted from higher average forward and daily NGL prices at June 30, 2009 as compared with the prices at December 31, 2008. Comparatively, at December 31, 2007 the average forward and daily prices for natural gas were lower than the prices at June 30, 2008, which produced $4.8 million of unrealized, non-cash, mark-to-market net gains on the derivative instruments used to fix the price of the natural gas we purchase for processing. These net gains were partially offset by unrealized, non-cash, mark-to-market net losses associated with the derivatives we use to fix the sales prices of a portion of the NGLs we derive from processing natural gas that resulted from higher average forward and daily NGL prices at June 30, 2008 relative to prices at December 31, 2007.

Operating income we derive from keep-whole processing arrangements for the six months ended June 30, 2009 was $28.1 million, representing a decrease of $19.9 million, or 41 percent, from the $48.0 million we produced for the same period in 2008. The favorable pricing environment that existed for NGLs and condensate for the six months ended June 30, 2008, did not exist for the same period in 2009 significantly reducing the operating income we derive from our keep-whole processing arrangements.

Operating and administrative costs of our Natural Gas segment were $4.6 million greater for the six months ended June 30, 2009 compared to the same period in 2008, primarily due to increased workforce-related costs associated with our systems. Enbridge Energy Company, Inc., our general partner, charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

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Future Prospects Update for Natural Gas

The following discussion provides an update to the status of projects we and Enbridge are developing and should be read in conjunction with the information included in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

Partnership Projects

Shelby County Loop and Compression

We commenced construction during the third quarter of 2008 to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. We have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. Commercial terms for this project predominately involve firm volume commitments from customers. During the second quarter of 2009, construction on the approximately $60 million project was substantially completed. Additional compression will be added over the next several months.

Enbridge Projects

LaCrosse Pipeline

The proposed interstate natural gas pipeline, known as the LaCrosse Pipeline, will run from our Carthage Hub in Panola County, Texas to the Sonat Pipeline in Washington Parish, Louisiana. The 300-mile pipeline, which would have a capacity of at least one billion cubic feet per day, is designed to provide an outlet for increasing supplies of natural gas originating in the East Texas and Fort Worth producing basins and the growing Haynesville Shale Play. The pipeline would interconnect with pipelines accessing the Perryville, Louisiana Hub as well as Louisiana industrial markets and pipelines serving southeastern U.S. markets. The pipeline would provide our customers with additional markets and options when transporting their natural gas. In May 2009, Enbridge conducted a successful non-binding open season for the proposed pipeline. The next stage of the project involves confirming customer interest and the expected cost of the new construction.

Marketing

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

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating revenues	$ 498.9	$ 1,406.8	$ 1,137.1	$ 2,521.1
Cost of natural gas	473.1	1,421.7	1,105.2	2,532.7
Operating and administrative	1.7	2.3	3.5	4.6
Depreciation and amortization	0.4	0.4	0.8	0.9
Operating expenses	475.2	1,424.4	1,109.5	2,538.2
Operating Income (Loss)	$ 23.7	$ (17.6)	$ 27.6	$ (17.1)

A majority of the operating income of our Marketing segment is derived from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers who need natural gas. As a result of our natural gas system expansions and other initiatives, our Marketing business now has access to several additional downstream natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

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Three months ended June 30, 2009 compared with three months ended June 30, 2008

The operating results of our Marketing segment for the three months ended June 30, 2009 were positively affected by unrealized, non-cash, mark-to-market net gains of $17.5 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. The non-cash, mark-to-market net gains during the three months ended June 30, 2009 resulted from narrower transportation differentials and the settlement of derivatives associated with our park and loan activities. The unrealized, non-cash, mark-to-market losses for the three months ended June 30, 2008 resulted from increases in the forward and daily market prices of natural gas from March 31, 2008. Partially offsetting the $22.0 million of losses associated was income derived from selling natural gas and NGLs into markets with more favorable pricing.

Six months ended June 30, 2009 compared with six months ended June 30, 2008

Similar to the three month analysis, operating income of our Marketing segment improved to $27.6 million for the six month period ended June 30, 2009 from a loss of $17.1 million for the corresponding period in 2008. Included in operating income for the first six months of 2009 are approximately $10.6 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment, which is a $45.5 million increase from the $34.9 million of unrealized, non-cash, mark-to-market losses for the comparable period of 2008. The unrealized, mark-to-market gains for the six months ended June 30, 2009 resulted primarily from narrower transportation differentials, while the unrealized, non-cash, mark-to-market losses of $34.9 million for the six months ended June 30, 2008 resulted from the increases in the forward and daily market prices of natural gas from December 31, 2007.

Corporate

Interest expense was $57.9 million and $109.2 million for the three and six months ended June 30, 2009, compared with $51.4 million and $79.0 million for the corresponding periods in 2008. The increases are primarily the result of higher weighted average debt balance associated with debt issuances that did not impact the first three months of 2008. The debt issuances that impacted the entire six month period ended June 30, 2009 are as follows:

- $400 million of our 6.5% Senior Notes in April 2008;
- $400 million of our 7.5% Senior Notes in April 2008; and
- $500 million of our 9.875% Senior Notes in December 2008.

Our weighted average interest rates are 6.9% and 7.0% for the three and six month periods ended June 30, 2009, respectively, as compared with our weighted average interest rates of 6.6% and 6.4% for the same periods in 2008.

We are exposed to interest rate risk associated with changes in interest rates on our variable rate debt. Our variable interest rate borrowing cost is determined at the time of each borrowing or interest rate reset based upon a posted London Interbank Offered Rate, or LIBOR, rate for the period of borrowing or interest rate reset, plus a defined credit spread. In order to mitigate the negative effect high interest rates have on our cash flows, we purchased interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness. The interest rate caps do not qualify for hedge accounting and, as a result, the fair values of these derivative financial instruments are recorded as assets or liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in Interest expense on our consolidated statements of income. For both the three and six month periods ended June 30, 2009 we recorded $2.4 million of unrealized, non-cash, mark-to-market net gains associated with the changes in fair value of these derivative that resulted from the increase in interest rates from the May 2009 date these derivative financial instruments were purchased to June 30, 2009.

Further contributing to the increase in interest expense is the $0.4 million decrease in interest capitalized to our construction projects in the three month period ended June 30, 2009 from the same period in 2008. The increase in interest expense in the six months ended June 30, 2009 was attributable to a $6.6 million reduction of capitalized interest when compared to the same period in 2008. For the three and six months ended June 30, 2009 and 2008, our interest cost is comprised of the following:

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Interest expense	$ 57.9	$ 51.4	$ 109.2	$ 79.0
Interest capitalized	5.5	5.9	18.4	25.0
Interest cost incurred	$ 63.4	$ 57.3	$ 127.6	$ 104.0

* Interest expense for the three and six months ended June 30, 2009 includes $2.4 million of unrealized, non-cash, mark-to-market gains associated with our interest rate caps.

LIQUIDITY AND CAPITAL RESOURCES

Impact of Current Economic Conditions

The recession that began in late 2007 continues to curtail demand for goods and services in the United States during the three and six months ended June 30, 2009. The effect of lower demand for goods and services translates into lower demand for crude oil and natural gas supplies by refiners, utilities and other end users of the products we transport on our pipelines. We have responded to these changes in our operating environment by taking steps to reduce our operating and administrative costs, which are evident in the near nominal change in these costs, despite the deployment of additional assets on our systems.

While the U.S. money supply remains at historically high levels, investors remain wary of investing in uncertain capital markets. As a result, liquidity constraints continue to exist within the capital markets of the United States and around the world. We continue to remain confident in our ability to obtain the capital necessary to fund our growth programs and maintain our credit rating, although the prices at which we can access capital remain higher than the prices we incurred for similar capital in recent years. Our cost for both debt and equity capital is likely to remain historically high throughout 2009 and possibly longer should capital markets remain constrained. As a result, we expect to selectively access the capital markets as necessary to fund our internal growth projects and continue to explore alternative means of financing our projects. For example, we recently announced a joint funding arrangement through which our general partner and other affiliates of ours and Enbridge Inc. will participate jointly in financing our portion of the construction of the Alberta Clipper project. Following our announcement, both Standard & Poor s Ratings Services and Moody s Investors Service revised their ratings outlook on our senior unsecured debt to stable from negative. Standard & Poor s also raised our short-term rating to A-2 from A-3, which will allow us to once again access the commercial paper market.

We continue to focus on maintaining sufficient liquidity to fund our remaining growth programs and sustain the present distribution rate to our unitholders, while preserving our credit rating. Our ability to maintain adequate liquidity may involve the issuance of debt and equity at less attractive terms than our most recent offerings and could involve the sale of non-core assets, and further asset partnership or joint venture arrangements or other strategies to limit the amount of external funding required for our growth projects. We continue to move forward with our commercially supported internal growth projects, although our capital spending, particularly on the natural gas side of our business, has been tempered to minimize our capital raising requirements. Our ability to access the capital markets to fund new projects in the future at prices that make the proposed projects accretive is likely to be limited. We may revise the timing and scope of other projects as necessary to adapt to existing economic conditions and minimize the decrease in incremental benefits expected to accrue to our unitholders from these projects that can result from the substantial cost of capital increases during this period.

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At June 30, 2009, we have in excess of $1.6 billion of liquidity to meet our ongoing operational, investment and finance needs, as noted below:

	(in millions)
Availability under Credit Facility	$ 618.7
Available under Enbridge (U.S.) Credit Agreement	500.0
Available under 364-Day Credit Facilities	350.0
Cash and cash equivalents	132.7
Total	$ 1,601.4

General

Our primary operating cash requirements consist of normal operating expenses, core maintenance activities, distributions to our partners and payments associated with our derivative activities. We expect to fund our current and future short-term cash requirements from our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Second Amended and Restated Credit Agreement, which we refer to as the Credit Facility.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. Our need for investment capital to fund our expansion projects, make acquisitions of new assets and businesses and to retire maturing or callable debt obligations is expected to be funded from several sources. We anticipate initially funding long-term cash requirements for expansion projects and acquisitions first from operating cash flows, second, from borrowings under our Credit Facility, and from borrowings under our credit agreement with Enbridge (U.S.) Inc., or Enbridge U.S., a wholly-owned subsidiary of Enbridge and from other potential sources of capital. Likewise, we anticipate initially retiring our maturing and callable debt with similar borrowings on these existing facilities. We expect to obtain permanent financing through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities.

Enbridge, as the ultimate parent of our general partner, has been and continues to be supportive of our efforts in executing our significant capital expenditure program as some of these projects are beneficial to our mutual customers and operational asset bases. In addition to the liquidity support Enbridge has provided in the recent past, Enbridge has the capacity to provide further support in the form of participation in public and private equity transactions, direct investment in specific projects of our subsidiaries and other non-traditional forms of investments in our operations.

Capital Resources

Joint Funding Arrangement

In July 2009 we announced a joint funding arrangement with our general partner and other affiliates of ours and Enbridge to participate in financing construction of the United States portion of our $1.2 billion Alberta Clipper project being constructed by Enbridge Energy, Limited Partnership, which we refer to as the Enbridge Partnership. Enbridge, through our general partner, will fund two-thirds of the debt financing for the project and two-thirds of the project s equity requirements directly into the Enbridge Partnership. We will fund one-third of the debt and equity financing required for the project. Enbridge, through our general partner, will be entitled to two-thirds of the earnings and cash flows that the Enbridge Partnership generates from the project. We will be entitled to one-third of the project s earnings and cash flows. We and our general partner each have a right of first refusal on the other s investment in the project and we will retain the right to fund up to 100 percent of any expansion of the project, which would result in a corresponding adjustment to our general partner s interest. Promptly following the in-service date for the project, we must use commercially reasonable efforts to issue debt in one or more capital market transactions, the proceeds of which would be used to refinance the loan we make to the Enbridge Partnership under the funding arrangement, on substantially the same terms as the debt issued in the capital market transaction. On the same date, our general partner will refinance its loans with respect to the project on the same terms as our refinanced loan to the Enbridge Partnership.

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these projects. We have issued securities generating proceeds in excess of $4 billion over the past three years through the issuance of a balanced combination of debt and equity securities to fund our expansion projects. Our planned internal growth projects will require additional permanent capital and continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them. Prevailing market conditions may limit our ability and willingness to complete future debt and equity offerings while the capital markets remain constrained and costs are high. 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.

Available Credit

Historically our two primary sources of liquidity have been the commercial paper market and our Credit Facility. From November 2008 until July 2009 we have been unable to access the commercial paper market due to a downgrade in our short-term credit rating by Standard and Poor s to A-3 from A-2 and have used our Credit Facility as our primary source of liquidity. In July 2009, Standard and Poor s revised their ratings on our short-term credit to A-2 from A-3, which will allow us to once again make use of our $600 million commercial paper program, depending on market conditions. We will continue to use our Credit Facility primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions and access the commercial paper market for similar temporary financing as economic conditions warrant. In addition to our Credit Facility and commercial paper program we have available a $500 million revolving credit agreement from Enbridge (U.S.). Additionally, in April 2009 we entered into 364-day revolving credit facilities totaling $350 million with Barclays Bank PLC, Export Development Canada and Enbridge (U.S.).

Credit Facility

On March 31, 2009, we amended our Credit Facility to remove Lehman Brothers Bank, FSB, which we refer to as Lehman BB, as a lender which effectively reduced the amounts available to us under our Credit Facility. The removal of Lehman BB permanently reduced both the amount we may borrow under the terms of our Credit Facility to $1,167.5 million as well as the number of committed lenders to 13. The amendment to our Credit Facility did not result in any changes to the pricing, fees or other commercial terms.

At June 30, 2009, we had $543.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.62% and letters of credit totaling $5.8 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the balance of our letters of credit outstanding.

At June 30, 2009, we could borrow $618.7 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$ 1,167.5
Less: Amounts outstanding under Credit Facility	(543.0)
Balance of letters of credit outstanding	(5.8)
Total amount we could borrow at June 30	$ 618.7

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, which typically is a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the six month periods ended June 30, 2009 and 2008, we net settled borrowings of approximately $957.1 million and $410 million, respectively, on a non-cash basis.

364-day Credit Facilities

In April 2009, we entered into two unsecured and non-guaranteed revolving credit facility agreements totaling $350 million for funding our general activities and working capital. The credit facility agreements include a $200 million agreement with Barclays Bank PLC, as administrative agent, and Barclays Bank PLC and Export Development Canada as lenders; and a $150 million affiliate credit agreement with Enbridge U.S. Both credit facilities mature 364 days from the closing date of the agreements and include one-year extensions for a fee, exercisable at our option. The $150 million Enbridge U.S. facility is on the same terms as the $200 million facility with third parties.

EUS Credit Agreement

In addition to our Credit Facility and the 364-day Credit Facilities, we have access to an unsecured three year revolving credit agreement with Enbridge U.S., which we refer to as the EUS Credit Agreement. The EUS Credit Agreement provides us with access to an additional $500 million of financing on substantially the same terms as our Credit Facility and matures in December 2010. The amounts available to us under the EUS Credit Agreement remain undrawn at June 30, 2009 and available for our use.

Cash Requirements for Future Growth

Capital Spending

We expect to make additional expenditures during the next year and a half for the construction of additional natural gas and crude oil transportation infrastructure primarily for the Alberta Clipper project. Anticipated growth in western Canadian oil sands production and the need to reach new markets has prompted the Southern Access, Alberta Clipper and related projects associated with our liquid systems. In 2009, we expect to spend approximately $1.5 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed into service. At June 30, 2009, we had approximately $136.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2009.

Forecast 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 includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. We also began including well-connects associated with our Natural Gas system assets as core maintenance expenditures beginning in 2009 which totaled $8.8 million for the six months ended June 30, 2009. 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 forecast expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2009. Although we anticipate making the expenditures in 2009, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. 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. We made capital expenditures of $544 million, including $31.2 million on core maintenance activities, for the six months ended June 30, 2009.

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For the full year ending December 31, 2009, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures (in billions)
System enhancements	$ 0.4
Core maintenance activities	0.1
Southern Access expansion	0.2
Alberta Clipper	0.8
	$ 1.5

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through June 30, 2009, the incremental capacity that will or has become available upon completion of the project and the periods we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures			
	Estimated Total Cost	Actual Expenditures through June 30, 2009	Estimated Incremental Capacity Oil (Kbpd)[(1)]	Expected Completion
	(in billions)			
Southern Access expansion (Lakehead)	$ 2.1	$ 2.1	400	Completed-April 2009
Alberta Clipper	1.2	0.3	450	Mid-2010
North Dakota Phase VI expansion	0.2	0.1	50	Early 2010
Total	$ 3.5	$ 2.5	900	

(1) Thousands of barrels per day (Kbpd).

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to moderate over the next 12 months as we progress and complete our Alberta Clipper and North Dakota projects. Core maintenance capital is anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding our portions of the system enhancement capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate, or through asset partnership or joint venture arrangements. As previously discussed, we intend to finance construction of the Alberta Clipper crude oil pipeline through a joint funding arrangement with Enbridge through our general partner and other affiliates of ours and Enbridge. Core maintenance expenditures are expected to be funded by operating cash flows.

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 or maintenance; however, these are viewed to be consistent with industry trends.

Derivative Activities

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative instruments at June 30, 2009:

	Notional	2009	2010	2011	2012	2013	Total
			(dollars, in millions)				
Swaps							
Natural gas[1]	230,933,300	$ (13.5)	$ (20.7)	$ (24.7)	$ (6.6)	$ 1.9	$ (63.6)
NGL[2]	5,905,582	12.7	11.0	10.0	10.7		44.4
Crude[2]	2,375,393	(1.7)	(2.4)	(4.5)	(1.6)	1.2	(9.0)
Options-calls							
Natural gas calls written[1]	914,000	(0.1)	(0.6)	(0.9)			(1.6)
Options-puts							
Natural gas puts purchased[1]	914,000						
NGL puts purchased[2]	1,464,060	2.9	6.0	2.3	3.7		14.9
Crude puts purchased[2]	384,300	0.2	1.5				1.7
Crude puts written[2]	36,500		(0.2)				(0.2)
Forward contracts							
NGL[2]	1,695,460	(0.8)	(0.1)				(0.9)
Totals		$ (0.3)	$ (5.5)	$ (17.8)	$ 6.2	$ 3.1	$ (14.3)

(1) Notional amounts for natural gas are recorded in MMBtu.

(2) Notional amounts for NGL and Crude are recorded in Bbl.

Operating Activities

Net cash provided by operating activities for the six months ended June 30, 2009 was $359.4 million, an increase of $85.7 million from the $273.7 million generated during the same period in 2008. The increase in operating cash flow is directly attributable to higher net income resulting from the improved operating performance of our Liquids and Natural Gas systems. Net cash provided by operating activities also increased due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $141.0 million less in our investing activities during the six months ended June 30, 2009 in relation to the same period in 2008. The decrease is primarily attributable to the $135.7 million reduction of amounts spent in the first six months of 2009 on our construction projects as compared to the same period of 2008. The decrease in the amounts spent on our construction projects is primarily attributable to completion of the first and second stages of our Southern Access expansion project.

Financing Activities

Net cash provided by financing activities during the six months ended June 30, 2009 was $10.7 million, compared with net cash provided by financing activities of $556.4 million for the corresponding period in 2008. The reduction in the amount of cash provided by financing activities is due primarily to the lower amount of cash generated from our unit issuances as well as the $800 million of Senior Note offerings that did not exist in the first six months of 2009 when compared to the same period in 2008. Additionally, in the first six months of 2009 we repaid $175 million of our senior notes and had additional distributions of $49.5 million as compared with the same period of 2008.

Partially offsetting the cash out flows from financing activities are $694.8 million of increases in short-term financing over the $318.6 million of repayments in the comparable period of 2008. For the six months ended June 30, 2009, we had gross borrowings of $2,062.1 million under our Credit Facility and gross repayments of $1,685.9 million, including $957.1 million of non-cash borrowings and repayments.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

We have evaluated events subsequent to June 30, 2009 through July 27, 2009, the date we issued these financial statements, and identified the events disclosed below.

Zero Coupon Senior Note Repayment

On July 21, 2009, we received notice that the holders of our senior, unsecured zero coupon notes due on August 28, 2022, referred to as the Zero Coupon Notes, have elected to exercise the call feature of the notes that require early repayment of the debt. We will be required to be repay the Zero Coupon Notes on August 28, 2009 at an amount of approximately $222.3 million, representing the principal amount of the Zero Coupon Notes on the repayment date. The carrying amount of our Zero Coupon Notes is currently included in Current maturities of long-term debt on our consolidated statement of financial position.

Joint Funding Arrangement for Alberta Clipper Project

For a discussion of the joint funding arrangement for our Alberta Clipper project entered into in July 2009, see the discussion in *Liquidity and Capital Resources*.

Distribution to Partners

On July 24, 2009, the Board of Directors of Enbridge Management declared a distribution payable to our partners on August 14, 2009. The distribution will be paid to unitholders of record as of August 6, 2009, of our available cash of $130.3 million at June 30, 2009, or $0.990 per common unit. Of this distribution, $93.4 million will be paid in cash, $15.5 million will be distributed in i-units to our i-unitholder, $20.7 million will be distributed in Class C units to the holders of our Class C units and $0.7 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

FERC Transportation Tariffs-Liquids

Effective July 1, 2009, we increased our rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, and does not apply to the SEP II, Terrace and Facilities surcharges. Effective July 2009, we increased the base tariff rates on our Lakehead system by an average of 7.6 percent to equal the indexed ceiling level allowed under the FERC s indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is $1.46 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2009. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 7.6 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology. We anticipate that operating revenues will increase by approximately $33 million over the next twelve months in connection with the transportation rate increases.

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REGULATORY MATTERS

FERC Transportation Tariffs Liquids

Effective April 1, 2009, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimates and actual cost and throughput data for the prior year and our projected costs and throughput for 2009 related to our expansion projects. The projected costs for 2009 include three additional projects, the most significant being the Southern Lights replacement capacity project. The projected costs also include a rate update for two existing projects including the Hartsdale tanks charge and the Southern Access Expansion for the inclusion of the recently completed Stage 2 of the project. This filing increased the average transportation rate for crude oil movements from the Canadian border to Chicago by approximately $0.15 per barrel, to an average of approximately $1.41 per barrel. We will begin to realize revenues in relation to this increased surcharge as crude oil is delivered from our pipeline, generally the month following the effective date of the tariff.

Effective May 1, 2009, we filed a tariff with the FERC to reflect the addition of Flanagan as a component of the Southern Access project expansion in order to facilitate movements that originate from the Canadian border and Clearbrook destined for delivery to Flanagan. Notwithstanding the new rates for the delivery point in Flanagan, all rates in this tariff filing remain unchanged from the tariff filing effective April 1, 2009, discussed above. The average transportation rate for crude oil movements from the Canadian border to Flanagan will be approximately $1.41 per barrel, which is in line with the average transportation rates from the Canadian border to Chicago discussed above.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

FASB Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board, or FASB, approved the FASB Accounting Standards Codification, which we refer to as the FASB ASC, or codification, as the single source of authoritative, nongovernmental Generally Accepted Accounting Principles, or GAAP. The FASB ASC reorganizes all of the pronouncements under GAAP and displays them in approximately 90 accounting topics. The reorganization and codification of GAAP was initiated by the FASB in an effort to:

- Reduce the amount of time and effort required to solve an accounting research issue.
- Mitigate the risk of noncompliance with standards through improved usability of the literature.
- Provide accurate information with real-time updates as new standards are released.
- Assist FASB with the research and convergence efforts required during the standard setting process.
- Become the authoritative source of literature for the completed XBRL taxonomy.

Included in the codification are relevant portions of authoritative content issued by the Securities and Exchange Commission, or SEC, as well as selected SEC staff interpretations and administrative guidance. The FASB ASC will be effective for both interim and annual reporting periods ending after September 15, 2009. We do not expect our adoption of the codification in the third quarter of 2009 to have a significant effect on our financial statements.

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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, 2008, 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 (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 variable rate debt obligations are issued. Our exposure to commodity price risk exists within our Natural Gas and Marketing 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/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

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Commodity Price Derivatives

The following tables provides information about our derivative instruments at June 30, 2009 and December 31, 2008, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

			At June 30, 2009				At December 31, 2008	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	**Notional(1)**	**Receive**	**Pay**	**Asset**	**Liability**	**Asset**	**Liability**
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural Gas	12,259,562	$ 3.96	$ 6.75	$ 0.4	$ (34.5)	$ 2.5	$ (56.0)
	NGL	44,863	20.78	37.81		(2.1)		(6.5)
Receive fixed/pay variable	Natural Gas	12,490,056	5.70	4.19	21.9	(3.1)	38.7	(19.6)
	NGL	1,965,672	45.82	38.27	16.7	(1.9)	70.0	
	Crude Oil	374,728	66.62	71.92	1.2	(2.9)	5.8	(0.6)
Receive variable/pay variable	Natural Gas	68,097,561	3.93	3.91	5.5	(3.7)	8.9	(12.8)
Options								
Calls (written)	Natural Gas	184,000	4.31	4.38		(0.1)		(0.6)
Puts (purchased)	Natural Gas	184,000	4.38	3.40				(1.2)
	NGL	656,328	36.57	35.41	2.9		9.3	
	Crude Oil	128,800	71.92	64.86	0.2			
Forward Sales								
Receive variable/pay fixed	NGL	568,620	46.30	43.85	1.4			
Receive fixed/pay variable	NGL	1,021,718	46.53	48.63		(2.2)		
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	10,397,990	$ 5.69	$ 6.43	$ 2.4	$ (10.0)	$ 2.5	$ (6.5)
	NGL	200,322	49.58	46.50	3.7	(1.0)		(1.3)
Receive fixed/pay variable	Natural Gas	16,814,622	4.97	5.83	5.5	(19.9)	2.2	(27.5)
	NGL	2,615,225	46.07	42.87	19.1	(10.8)	28.0	
	Crude Oil	720,790	71.95	75.35	3.9	(6.3)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	75,292,893	5.72	5.70	2.9	(1.6)	0.8	(3.1)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.06		(0.6)		(1.0)
Puts (written)	Crude Oil	36,500	67.75	75.35		(0.2)		
Puts (purchased)	Natural Gas	365,000	6.06	3.40				
	NGL	595,680	46.04	42.85	6.0		5.2	
	Crude Oil	255,500	75.41	69.76	1.5			
Forward Sales								
Receive variable/pay fixed	NGL	10,000	36.18	28.56	0.1			
Receive fixed/pay variable	NGL	95,122	39.67	41.68		(0.2)		
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	2,944,510	$ 6.58	$ 7.20	$ 2.4	$ (4.1)	$ 2.6	$ (3.4)
	NGL	2,857	66.72	47.67	2.2			
Receive fixed/pay variable	Natural Gas	9,301,675	4.19	6.82	1.4	(25.1)	1.1	(28.1)
	NGL	581,810	55.84	42.01	9.1	(1.3)	13.0	(0.3)
	Crude Oil	621,875	71.24	78.39	1.1	(5.6)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.73	6.69	1.3	(0.6)		(1.0)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.89		(0.9)		(1.0)
Puts (purchased)	Natural Gas	365,000	6.89	3.40				
	NGL	83,220	63.34	38.41	2.3		2.7	
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	1,661,265	$ 6.85	$ 7.94	$ 0.7	$ (2.4)	$ 0.8	$ (2.1)
	NGL	36,600	38.16	55.58		(0.6)		(0.9)
Receive fixed/pay variable	Natural Gas	2,175,556	4.68	7.25	0.2	(5.5)		(5.8)
	NGL	458,232	70.56	44.05	11.3		15.7	
	Crude Oil	366,000	75.72	80.30		(1.6)	0.8	
Receive variable/pay variable	Natural Gas	1,089,000	6.84	6.48	0.4			

Options								
Puts (purchased)	NGL	128,832	66.80	41.22	3.7		4.4	
Contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	896,805	$ 6.90	$ 6.88	$ 0.1	$ (0.1)	$	$
Receive fixed/pay variable	Natural Gas	1,626,805	8.20	6.92	2.0	(0.1)	2.0	
	Crude Oil	292,000	86.41	81.88	2.7	(1.5)	3.4	

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at June 30, 2009 and December 31, 2008, 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.

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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.

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

	June 30, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$	$
AA	4.3	(39.6)
A	(27.6)	73.3
Lower than A	(0.9)	(1.2)
	(24.2)	32.5
Credit valuation adjustment	0.7	2.2
Total	$ (23.5)	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

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Interest Rate Derivatives

The following table provides information about our current interest rate derivatives for the specified periods.

		Partnership			Fair Value	
	Notional Principal (dollars in millions)	Pays	Receives	Maturity Date	June 30, 2009	December 31, 2008
					(dollars in millions)	
Interest Rate Swaps						
Floating to Fixed:						
	$ 50.0	4.6175%	LIBOR[2]	January 15, 2009	$	$
	$ 50.0	4.6130%	LIBOR	January 29, 2009		
	$ 50.0	4.6525%	LIBOR	February 13, 2009		(0.1)
	$ 50.0	4.5875%	LIBOR	February 20, 2009		(0.2)
	$ 50.0	1.6510%	LIBOR	December 2, 2010	(0.1)	
	$ 50.0	1.6570%	LIBOR	December 5, 2010	(0.1)	
	$ 50.0	1.6870%	LIBOR	December 12, 2010	(0.1)	
	$ 50.0	1.7040%	LIBOR	December 14, 2010	(0.1)	
	$ 50.0	1.7180%	LIBOR	December 18, 2010	(0.1)	
	$ 50.0	4.3700%	LIBOR-21 bps[1]	June 1, 2013	(3.7)	(5.3)
	$ 50.0	4.3425%	LIBOR-21 bps	June 1, 2013	(3.6)	(5.2)
	$ 25.0	4.3100%	LIBOR-25 bps	June 1, 2013	(1.8)	(2.7)
	$ 50.0	4.1160%	LIBOR	December 2, 2013	(0.7)	
	$ 50.0	4.1250%	LIBOR	December 4, 2013	(0.7)	
	$ 50.0	4.1320%	LIBOR	December 8, 2013	(0.7)	
	$ 50.0	4.1270%	LIBOR	December 10, 2013	(0.7)	
	$ 50.0	4.1570%	LIBOR	December 12, 2013	(0.7)	
	$ 50.0	4.1720%	LIBOR	December 14, 2013	(0.7)	
	$ 75.0	4.1380%	LIBOR	December 15, 2013	(1.0)	
	$ 50.0	4.1740%	LIBOR	December 18, 2013	(0.7)	
	$ 50.0	4.1920%	LIBOR	December 22, 2013	(0.7)	
	$ 125.0	4.1680%	LIBOR	December 31, 2013	(1.8)	
Fixed to Floating:						
	$ 25.0	LIBOR-25bps	4.7500%	June 1, 2013	2.2	3.1
	$ 50.0	LIBOR-21bps	4.7500%	June 1, 2013	4.4	6.1
	$ 50.0	LIBOR-21bps	4.7500%	June 1, 2013	4.4	6.1
Treasury Locks:						
	$ 20.0	4.6230%	LIBOR	June 30, 2020	(0.5)	
	$ 200.0	4.6190%	LIBOR	June 30, 2020	(5.0)	
Interest Rate Caps:						
	$ 25.0	1.0900%	N/A	December 17, 2010	0.1	
	$ 50.0	1.1500%	N/A	December 22, 2010	0.3	
	$ 125.0	1.0700%	N/A	December 31, 2010	0.8	
	$ 50.0	1.1450%	N/A	January 4, 2011	0.3	
	$ 25.0	1.1500%	N/A	January 8, 2011	0.2	
	$ 50.0	1.1150%	N/A	January 10, 2011	0.3	
	$ 75.0	1.1500%	N/A	January 15, 2011	0.5	

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

(2) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

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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 in our annual and quarterly reports under the Securities Exchange Act of 1934, as amended within the time periods specified in the SEC s rules and forms. These disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, 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 has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2009. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. 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. We have not made any changes that materially affected, nor are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended June 30, 2009.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 9, which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to the risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008 and Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2009.

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 27, 2009	By: /s/ STEPHEN J. J. LETWIN Stephen J. J. Letwin *Managing Director* *(Principal Executive Officer)*
Date: July 27, 2009	By: /s/ MARK A. MAKI Mark A. Maki *Vice President Finance* *(Principal Financial Officer)*

Index of Exhibits

Each exhibit identified below is filed as a part of this quarterly report. 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. Exhibits designated with a + constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (No. 33-43425)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership s 2000 Form 10-K/A filed on October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 16, 2006).
3.4	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on January 3, 2008).
3.5	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 7, 2008).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership s 2000 Form 10-K/A filed on October 9, 2001).
10.1	Contribution Agreement, dated July 17, 2009, by and among Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C., Enbridge Energy, Limited Partnership, Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C. and Enbridge Pipelines (Wisconsin) Inc. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on July 22, 2009).
10.2*+	Enbridge Inc. Incentive Stock Option Plan (2002), effective May 3, 2002.
10.3*+	Enbridge Inc. Incentive Stock Option Plan (2007), effective January 1, 2007.
10.4*+	Enbridge Inc. Performance Stock Option Plan (2007), effective January 1, 2007.
10.5*+	Enbridge Inc. Performance Stock Unit Plan (2007), effective January 1, 2007.
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.