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

FORM 10-Q

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

For the quarterly period ended March 31, 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 incorporation or organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, TX 77002
(Address of principal executive offices and zip code)
(713) 821-2000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T 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.

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

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

The Registrant had 76,088,834 Class A common units outstanding as of May 4, 2009.

ENBRIDGE ENERGY PARTNERS, L.P.

TABLE OF CONTENTS

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.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions, except per share amounts)	
Operating revenue	$1,459.7	$2,435.3
Operating expenses		
Cost of natural gas (Notes 4, 10 and 11)	1,102.1	2,098.8
Operating and administrative	137.7	116.7
Power	33.4	38.3
Depreciation and amortization (Note 5)	64.1	49.2
	1,337.3	2,303.0
Operating income	122.4	132.3
Interest expense	51.3	27.6
Other expense	0.5	0.3
Income from continuing operations before income tax expense	70.6	104.4
Income tax expense	2.0	1.3
Net income	$ 68.6	$ 103.1
Net income allocable to limited partner units (Note 2)	$ 55.0	$ 91.9
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.47	$ 0.99
Weighted average limited partner units outstanding	115.0	92.6

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions, except per share amounts)	
Net income	$68.6	$103.1
Other comprehensive income (loss), net of tax benefit (expense) of $(0.1) and $0.2, respectively (Note 11)	5.6	(26.3)
Comprehensive income	$74.2	$ 76.8

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the three months ended March 31, 2009	2008
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 68.6	$ 103.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	64.1	49.2
Derivative fair value (gains) losses (Notes 10 and 11)	16.9	(13.7)
Inventory market price adjustments (Note 4)	3.3	—
Other	5.1	5.5
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(1.3)	20.7
Due from General Partner and affiliates (Note 8)	15.7	0.6
Accrued receivables	138.3	(63.8)
Inventory (Note 4)	12.3	21.1
Current and long term other assets (Notes 10 and 11)	(18.5)	1.0
Due to General Partner and affiliates (Note 8)	3.0	(1.9)
Accounts payable and other (Notes 3, 10 and 11)	(24.3)	(0.3)
Accrued purchases	(60.3)	118.5
Interest payable	51.9	28.4
Property and other taxes payable	1.1	7.8
Settlement of interest rate derivatives	(0.7)	—
Net cash provided by operating activities	275.2	276.2
Cash used in investing activities		
Additions to property, plant and equipment (Note 5)	(212.9)	(373.5)
Changes in construction payables	(12.9)	(63.2)
Changes in restricted cash (Note 3 and 6)	0.1	—
Other	—	(5.3)
Net cash used in investing activities	(225.7)	(442.0)
Cash provided by (used in) financing activities		
Net proceeds from unit issuances	—	221.8
Distributions to partners (Notes 7 and 14)	(93.2)	(66.0)
Repayments of long-term debt (Note 6)	(175.0)	—
Net borrowings under Credit Facility (Note 6)	53.2	130.0
Net commercial paper repayments (Note 6)	—	(44.7)
Net cash provided by (used in) financing activities	(215.0)	241.1
Net increase (decrease) in cash and cash equivalents	(165.5)	75.3
Cash and cash equivalents at beginning of year	339.9	50.5
Cash and cash equivalents at end of period	$ 174.4	$ 125.8

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2009	December 31, 2008
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 174.4	$ 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	104.3	103.0
Due from General Partner and affiliates (Note 8)	24.8	40.5
Accrued receivables	368.6	507.3
Inventory (Note 4)	37.4	53.0
Other current assets (Notes 10 and 11)	69.3	80.7
	778.8	1,124.5
Property, plant and equipment, net (Note 5)	7,032.1	6,722.9
Goodwill	256.5	256.5
Intangibles, net	87.7	88.7
Other assets, net (Notes 10 and 11)	103.8	108.3
	$8,258.9	$8,300.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 8)	$ 68.4	$ 42.2
Accounts payable and other (Notes 3, 9, 10 and 11)	161.0	225.3
Accrued purchases	320.8	381.2
Interest payable	85.9	34.0
Property and other taxes payable	33.9	32.8
Current maturities of long-term debt (Note 6)	248.5	420.7
	918.5	1,136.2
Long-term debt (Note 6)	3,276.8	3,223.4
Notes payable to affiliate	130.0	130.0
Other long-term liabilities (Notes 9, 10 and 11)	65.0	84.4
	4,390.3	4,574.0
Commitments and contingencies (Note 9)		
Partners' capital (Note 7)		
Class A common units (76,088,834 at March 31, 2009 and December 31, 2008, respectively)	2,064.1	2,104.0
Class B common units (3,912,750 at March 31, 2009 and December 31, 2008)	83.1	85.0
Class C units (20,313,522 and 19,688,968 at March 31, 2009 and December 31, 2008, respectively)	896.4	886.5
i-units (15,247,549 and 14,763,055 at March 31, 2009 and December 31, 2008, respectively)	561.2	553.8
General Partner	245.3	84.7
Accumulated other comprehensive income (Notes 10 and 11)	18.5	12.9
	3,868.6	3,726.9
	$8,258.9	$8,300.9

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. 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 March 31, 2009 and December 31, 2008; and our results of operations and cash flows for the three month periods ended March 31, 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 month period ended March 31, 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 adopted the provisions of Emerging Issues Task Force ("EITF") Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited* Partnerships ("EITF No. 07-4") effective January 1, 2009. Under the two-class method, we allocate our net income, including any incentive distribution rights ("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 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%

We determined net income per limited partner unit as follows:

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions, except per unit amounts)	
Net income	$ 68.6	$ 103.1
Less distributions paid:		
Incentive distributions to General Partner	(12.5)	(9.1)
Distributed earnings allocated to General Partner (2%)	(2.3)	(1.9)
Total distributed earnings to General Partner	(14.8)	(11.0)
Total distributed earnings to limited partners (98%)	(114.4)	(91.2)
Total distributed earnings	(129.2)	(102.2)
Undistributed (overdistributed) earnings	$ (60.6)	$ 0.9
Weighted average limited partner units outstanding	115.0	92.6
Limited partner interests		
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit	$ 0.99(1)	$ 0.98(1)
Undistributed (overdistributed) earnings per limited partner unit	(0.52)(2)	0.01(3)
Net income per limited partner unit (basic and diluted)	$ 0.47	$ 0.99

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

(2) Equal to the limited partners' share (98%) of overdistributed earnings divided by the weighted average number of limited partner interests outstanding for the period.

(3) Undistributed earnings are allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

Our adoption of the provisions of EITF 07-4 resulted in a $0.01 reduction of net income per limited partner unit for the three months ended March 31, 2009 from the method we previously used to calculate our earnings per limited partner unit. The change in calculating earnings per limited partner unit for the three months ended March 31, 2008 did not yield any difference.

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 $21.2 million at March 31, 2009 and $30.5 million at December 31, 2008, are included in "Accounts payable and other" on our consolidated statements of financial position.

In September 2008, following the bankruptcy filing by Lehman Brothers Holdings Inc. ("Lehman"), Lehman Brothers Bank, FSB ("Lehman BB"), as discussed in Note 6, ceased to honor its funding commitment under the terms of our Second Amended and Restated Credit Agreement ("Credit Facility"). As a result, Bank of America, N.A., as administrative agent to our Credit Facility, 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 BB. The amount of cash collateral required to be posted was $0.1 million at December 31, 2008. On March 31, 2009, the Credit Facility was amended to remove Lehman BB, from our Credit Facility, which eliminated the collateral requirement imposed on us by Bank of America, N.A., as administrative agent. At March 31, 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:

	March 31, 2009	December 31, 2008
	(in millions)	
Materials and supplies	$ 4.2	$ 3.9
Liquids inventory	5.2	7.1
Natural gas and NGL inventory	28.0	42.0
	$37.4	$53.0

The cost of natural gas on our consolidated statements of income includes charges totaling $3.3 million for the three months ended March 31, 2009 that we recorded to reduce the cost basis of our natural gas inventory to reflect market value.

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	March 31, 2009	December 31, 2008
	(in millions)	
Land	$ 18.8	$ 17.9
Rights-of-way	445.6	437.1
Pipelines	4,535.8	4,327.8
Pumping equipment, buildings and tanks	1,027.5	995.4
Compressors, meters, and other operating equipment	648.4	639.3
Vehicles, office furniture and equipment	160.1	153.0
Processing and treating plants	330.5	343.1
Construction in progress	1,162.6	1,057.0
Total property, plant and equipment	8,329.3	7,970.6
Accumulated depreciation	(1,297.2)	(1,247.7)
Property, plant and equipment, net	$ 7,032.1	$ 6,722.9

6. DEBT

Credit Facility

On March 31, 2009, we amended our Credit Facility to remove Lehman BB, a subsidiary of Lehman, as a party to the Credit Facility, following Lehman's filing for bankruptcy protection under Chapter 11 of the United States ("U.S.") Bankruptcy Code in September 2008. Lehman BB ceased to honor its commitments under the Credit Facility of $82.5 million, effectively reducing the amounts available to us under our Credit Facility to $1,167.5 million. 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 March 31, 2009, we had $220.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.83% and letters of credit totaling $6.1 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 March 31, 2009, we could borrow $941.4 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	(220.0)
Balance of letters of credit outstanding	(6.1)
Total amount we could borrow at March 31	$ 941.4

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 amounts due. During the three month periods ended March 31, 2009 and 2008, we net settled borrowings of approximately $240 million and $390 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.

7. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") during the three months ended March 31, 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)					
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 484,494 i-units to Enbridge Management.

(2) During 2009, in lieu of cash distributions, we issued 624,554 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.

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 Inc. ("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 the ongoing operations of the Partnership, but is strategically aligned with Enbridge's offshore operations.

Purchase of Line Pipe

We, our general partner and Enbridge Pipelines Inc. ("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 $23.2 million, approximately 23 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. ("Southern Lights"), a wholly-owned subsidiary of our general partner, we completed the transfer of a 156-mile section of pipeline from our Lakehead system ("Line 13") to Southern Lights, in exchange for a newly constructed light sour pipeline. 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 back 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 will be recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow is expected to approximate zero. The exchange resulted in a $160.7 million increase in "Property, plant and equipment" and the capital account of our general partner included in "Partners' capital" on our March 31, 2009 consolidated statement of financial position for the $165.7 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. The light sour line is newer and has a slightly higher capacity than the Line 13 pipeline, 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 expense is anticipated to increase in future periods due to the higher book value associated with these assets.

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 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 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 March 31, 2009 and December 31, 2008, we have recorded $5.1 million and $5.5 million, respectively, in "Accounts payable and other" and $3.2 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. FAIR VALUE MEASUREMENTS

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 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.

	Fair Value at March 31, 2009			
Recurring fair value measures	**Level 1**	**Level 2**	**Level 3**	**Total**
		(in millions)		
Assets:				
Derivative instruments, net	$ 21.7	$2.0	$ 87.0	$110.7
Liabilities:				
Derivative instruments, net	(44.0)	—	(24.1)	(68.1)
Total	$(22.3)	$2.0	$ 62.9	$ 42.6

The table below provides a summary of changes in the fair value of our Level 3 financial assets and liabilities for the three months ended March 31, 2009. As reflected in the table, the net unrealized losses on Level 3 financial assets and liabilities was $9.6 million for the three months ended March 31, 2009, which resulted from forward price increases in natural gas liquids (“NGLs”), including condensate in the form of crude oil derivative instruments that we held at March 31, 2009. 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.

	Derivative Instruments, net
	(in millions)
Balance at January 1, 2009	$ 91.8
Realized and unrealized net losses	(27.1)
Purchases and settlements	—
Transfer out of Level 3	(1.8)
Balance at March 31, 2009	$ 62.9
Change in unrealized net losses relating to instruments still held at March 31, 2009	$ (9.6)

11. 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 (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. We have hedged a portion of our exposure to the variability in future cash flows associated with forecasted natural gas and NGL sales and purchases 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 ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive, other than in a forced or liquidation sale, 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.

Under the guidance of FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or 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" ("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 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 as set forth in SFAS No. 133, 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 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 under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 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" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **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 under SFAS No. 133, 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.

2. **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, given 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.

3. **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 under SFAS No. 133 and 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.

4. **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 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.

In each of the instances 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 utilize for the derivative financial instruments employed 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 March 31,	
	2009	2008
	(in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ (0.2)	$ (1.8)
Non-qualified hedges	(9.8)	28.6
Marketing		
Non-qualified hedges	(6.9)	(12.9)
Commodity derivative fair value gains (losses)	(16.9)	13.9
Corporate		
Non-qualified interest rate hedges	—	(0.2)
Derivative fair value gains (losses)	$(16.9)	$ 13.7

Derivative Positions

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

	March 31, 2009	December 31, 2008
	(in millions)	
Other current assets	$ 59.8	$ 70.6
Other assets, net	72.4	75.7
Accounts payable and other	(38.7)	(40.6)
Other long-term liabilities	(50.9)	(71.0)
	$ 42.6	$ 34.7

The changes in net assets associated with derivative activities are primarily due to the decrease in current and forward natural gas prices from December 31, 2008 to March 31, 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 months ended March 31, 2009 and 2008, we reclassified unrealized net gains of $9.9 million and unrealized net losses of $31.3 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. We estimate that approximately $36.0 million of AOCI, representing unrealized net gains on cash flow hedging activities based on pricing and positions at March 31, 2009, will be reclassified to earnings during the next twelve months.

As of March 31, 2009, we have provided $4.3 million of collateral in the form of letters of credit to our counterparties pursuant to the terms of our International Securities Dealers Association ("ISDA®") agreements.

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

	March 31, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(0.3)	(39.6)
A	43.1	73.3
Lower than A	(0.5)	(1.2)
	42.3	32.5
Credit valuation adjustment	0.3	2.2
Total	$42.6	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

As the net value of our derivative financial instruments has increased in response to decreases in forward commodity prices, we continue to closely monitor our outstanding financial exposure. 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 March 31, 2009, we were in an overall net asset position of $42.6 million, which included liabilities of $89.6 million for which we were required to provide $4.3 million in the form of letters of credit to our counterparties under the ISDA® agreements based on the thresholds then in effect. Based on our forward positions at March 31, 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 $29.3 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements. If our credit ratings were further downgraded to below investment grade an additional $29.7 million would be required to be posted 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. A net asset, or receivable position, of approximately $92.1 million as of March 31, 2009 is due to us from U.S. financial institutions, including investment banks. We are in a net liability position of $21.8 million with integrated oil companies and a net liability position of $27.7 million with non-U.S. financial institutions. We are holding no cash collateral on our asset exposures pursuant to the margin thresholds in effect at March 31, 2009 under our ISDA® agreements and $4.3 million has been posted under letters of credit relating to our liability exposure.

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.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	March 31, 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	$ —
Interest rate contracts	Other assets, net	—	Other long-term liabilities	—
Commodity contracts	Other current assets	66.3	Accounts payable and other	(32.3)
Commodity contracts	Other assets, net	47.4	Other long-term liabilities	(36.4)
		113.7		(68.7)
Derivatives not designated as hedging instruments under SFAS No. 133				
Interest rate contracts	Other current assets	4.7	Accounts payable and other	(4.2)
Interest rate contracts	Other assets, net	9.9	Other long-term liabilities	(8.4)
Commodity contracts	Other current assets	22.5	Accounts payable and other	(37.0)
Commodity contracts	Other assets, net	25.5	Other long-term liabilities	(15.4)
		62.6		(65.0)
Total derivative instruments		$176.3		$(133.7)

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

Three months ended March 31, 2009					
Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	**Amount of gain (loss) recorded 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	$ —	Interest expense	$ 0.9	Interest expense	$ —
Commodity contracts	6.4	Cost of natural gas	10.1	Cost of natural gas	(0.2)
Total	$6.4		$11.0		$(0.2)

The amount of loss recognized in income represents $0.2 million related to the ineffective portion of the hedging relationships.

Effect of Derivative Instruments on Consolidated Statement of Income

Three months ended March 31, 2009		
Derivatives Not Designated as Hedging Instruments under Statement 133	**Location of Gain or (Loss) Recognized in earnings**	**Amount of Gain or (Loss) Recognized in earnings**
(in millions)		
Interest rate contracts	Interest expense	$ —
Commodity contracts	Cost of natural gas	(16.7)
Total		$(16.7)

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	March 31, 2009		
	Assets	**Liabilities**	**Total**
Fair value of derivatives—gross presentation	$176.3	$(133.7)	$42.6
Effects of netting agreements	(44.1)	44.1	—
Fair value of derivatives—net presentation	$132.2	$ (89.6)	$42.6

Commodity Price Derivatives

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

	At March 31, 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	18,906,195	$ 3.58	$ 7.06	$ 0.4	$(70.5)	$ 2.5	$(56.0)
	NGL	132,950	30.16	63.63	—	(4.4)	—	(6.5)
Receive fixed/pay variable	Natural Gas	16,567,705	6.02	4.04	37.9	(4.8)	38.7	(19.6)
	NGL	2,937,825	45.82	29.45	47.9	—	70.0	—
	Crude Oil	266,875	69.26	54.97	4.3	(0.4)	5.8	(0.6)
Receive variable/pay variable	Natural Gas	96,573,109	3.73	3.73	7.2	(6.8)	8.9	(12.8)
Options								
Calls (written)	Natural Gas	275,000	4.31	4.32	—	(0.1)	—	(0.6)
Puts (written)	Natural Gas	137,345	3.69	7.28	—	(0.5)	—	—
Puts (purchased)	Natural Gas	370,000	4.56	3.47	0.1	—	—	(1.2)
	NGL	431,000	45.98	32.06	6.7	—	9.3	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	4,488,550	$ 5.44	$ 7.34	$ 1.7	$(10.1)	$ 2.5	$ (6.5)
	NGL	165,625	43.73	48.70	0.5	(1.3)	—	(1.3)
Receive fixed/pay variable	Natural Gas	11,636,287	4.64	5.73	5.6	(18.2)	2.2	(27.5)
	NGL	1,513,655	49.12	30.22	28.2	—	28.0	—
	Crude Oil	525,150	71.76	62.68	5.9	(1.1)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	64,508,963	5.58	5.63	0.7	(3.9)	0.8	(3.1)
Options								
Calls (written)	Natural Gas	365,000	4.31	5.93	—	(0.6)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	5.93	3.40	—	—	—	—
	NGL	245,280	56.60	35.80	5.9	—	5.2	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	2,944,510	$ 6.25	$ 7.20	$ 2.2	$ (4.9)	$ 2.6	$ (3.4)
	NGL	10,000	51.75	47.67	—	—	—	—
Receive fixed/pay variable	Natural Gas	9,301,675	4.19	6.57	2.0	(23.4)	1.1	(28.1)
	NGL	581,810	55.84	33.64	12.5	—	13.0	(0.3)
	Crude Oil	538,375	71.70	67.62	3.5	(1.6)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.44	6.49	0.4	(1.2)	—	(1.0)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.67	—	(0.8)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	6.67	3.40	—	—	—	—
	NGL	83,220	63.34	30.95	2.8	—	2.7	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	941,709	$ 6.80	$ 8.72	$ 0.7	$ (2.4)	$ 0.8	$ (2.1)
	NGL	36,600	31.13	55.58	—	(0.8)	—	(0.9)
Receive fixed/pay variable	Natural Gas	1,456,000	3.57	7.33	—	(5.2)	—	(5.8)
	NGL	458,232	70.56	35.46	15.2	—	15.7	—
	Crude Oil	219,600	74.85	70.36	0.9	—	0.8	—
Receive variable/pay variable	Natural Gas	1,089,000	6.45	6.27	0.2	—	—	—
Options								
Puts (purchased)	NGL	128,832	66.80	33.33	4.5	—	4.4	—
Contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 6.78	$ 2.0	$ —	$ 2.0	$ —
	Crude Oil	73,000	124.05	72.40	3.4	—	3.4	—

(1) Volumes of Natural gas are measured in millions of British Thermal Units ("MMBtu"), whereas volumes of NGL and Crude are measured in barrels ("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 March 31, 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.

Interest Rate Derivatives

We enter into interest rate swaps, collars 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.

		Partnership			Fair Value	
	Notional Principal	**Pays**	**Receives**	**Maturity Date**	**March 31, 2009**	**December 31, 2008**
	(dollars in millions)				**(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	4.3700%	LIBOR-21 bps[1]	June 1, 2013	(5.1)	(5.3)
	$50.0	4.3425%	LIBOR-21 bps	June 1, 2013	(5.0)	(5.2)
	$25.0	4.3100%	LIBOR-25 bps	June 1, 2013	(2.5)	(2.7)
Fixed to Floating:						
	$50.0	LIBOR-21 bps	4.7500%	June 1, 2013	5.8	6.1
	$50.0	LIBOR-21 bps	4.7500%	June 1, 2013	5.8	6.1
	$25.0	LIBOR-25 bps	4.7500%	June 1, 2013	3.0	3.1

(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.

Our short-term floating to fixed rate interest rate swaps, with the exception of the contract that matured February 13, 2009, qualify for hedge accounting treatment pursuant to the requirements of SFAS No. 133 and have been designated as cash flow hedges of future interest payments on $150 million of our variable rate indebtedness. As such, 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 "Accumulated other comprehensive income," or AOCI. We discontinued hedge accounting treatment in December 2008 for our floating to fixed rate interest rate swap that matured February 13, 2009 originally hedging $50 million of our variable rate indebtedness when we reduced the balance of our Credit Facility below $200 million. As such, changes in the fair value of this derivative financial instrument are recorded in earnings as an increase or decrease in "Interest expense."

The long-term floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 have not been designated as cash flow or fair value hedges under SFAS No. 133 and, as a result, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense.

12. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present financial information about our business segments:

	As of and for the three months ended March 31, 2009				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 219.7	$ 994.4	$649.3	$ —	$1,863.4
Less: Intersegment revenue	0.3	392.3	11.1	—	403.7
Operating revenue	219.4	602.1	638.2	—	1,459.7
Cost of natural gas	—	470.0	632.1	—	1,102.1
Operating and administrative	54.4	80.6	1.8	0.9	137.7
Power	33.4	—	—	—	33.4
Depreciation and amortization	29.4	34.3	0.4	—	64.1
Operating income	102.2	17.2	3.9	(0.9)	122.4
Interest expense	—	—	—	51.3	51.3
Other expense	—	—	—	0.5	0.5
Income before income tax expense	102.2	17.2	3.9	(52.7)	70.6
Income tax expense	—	—	—	2.0	2.0
Net income	$ 102.2	$ 17.2	$ 3.9	$ (54.7)	$ 68.6
Total assets	$4,262.9	$3,529.0	$206.8	$260.2	$8,258.9
Capital expenditures (excluding acquisitions)	$ 162.5	$ 47.0	$ —	$ 3.4	$ 212.9

(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 three months ended March 31, 2008				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 157.0	$1,874.1	$1,198.8	$ —	$3,229.9
Less: Intersegment revenue	—	710.1	84.5	—	794.6
Operating revenue	157.0	1,164.0	1,114.3	—	2,435.3
Cost of natural gas	—	987.8	1,111.0	—	2,098.8
Operating and administrative	37.5	74.9	2.3	2.0	116.7
Power	38.3	—	—	—	38.3
Depreciation and amortization	19.6	29.1	0.5	—	49.2
Operating income	61.6	72.2	0.5	(2.0)	132.3
Interest expense	—	—	—	27.6	27.6
Other expense	—	—	—	0.3	0.3
Income before income tax expense	61.6	72.2	0.5	(29.9)	104.4
Income tax expense	—	—	—	1.3	1.3
Net income	$ 61.6	$ 72.2	$ 0.5	$ (31.2)	$ 103.1
Total assets	$3,252.8	$3,439.3	$ 438.5	$184.8	$7,315.4
Capital expenditures (excluding acquisitions)	$ 296.8	$ 73.5	$ —	$ 3.2	$ 373.5

(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.

13. UNRECORDED REVENUES

Enbridge Energy, Limited Partnership (the "Enbridge Partnership"), our wholly-owned subsidiary, is party to a joint tariff agreement with Mustang Pipe Line, LLC, ("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 their pipeline system to markets south of Chicago. The joint tariff agreement in place with Mustang allows for shippers on our Lakehead system to reach markets downstream of Chicago by providing committed shippers with a discounted transportation rate for their agreements to transport crude oil exiting our Lakehead system in the Chicago region through 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 did not record approximately $13.8 million of operating revenues on our Lakehead system from October 2005 through December 2008. The unrecorded revenues 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 three months ended March 31, 2009.

14. SUBSEQUENT EVENTS

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.) Inc. ("Enbridge U.S."), a wholly and directly owned subsidiary of Enbridge. 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.

Distribution to Partners

On April 30, 2009, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2009. The distribution will be paid to unitholders of record as of May 7, 2009, of our available cash of $129.2 million at March 31, 2009, or $0.990 per common unit. Of this distribution, $93.3 million will be paid in cash, $15.1 million will be distributed in i-units to our i-unitholder, $20.1 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.

15. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Interim Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued FASB Staff Position ("FSP") FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. The objective of the FSP is to increase the frequency of similar types of disclosures regarding the fair values of financial instruments to improve the transparency of information for financial statement users. The provisions require disclosure of the following on both an interim and annual basis:

- The fair value of all financial instruments, whether or not recognized in the statement of financial position;
- Fair value information disclosed in the notes shall be presented together with the related carrying amount in a form that makes it clear whether the fair value and carrying amount represent assets or liabilities and how the carrying amount relates to what is reported in the statement of financial position; and
- The method(s) and significant assumptions used to estimate the fair value of financial instruments.

The FSP is effective for interim and annual reporting periods ending after June 15, 2009, with earlier application of the provisions of the FSP permitted. The FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, the FSP requires comparative disclosures only for periods ending subsequent to the initial adoption date. We did not adopt the provisions of this pronouncement early and we do not expect our adoption of the FSP in the second quarter of 2009 to have a significant effect on our financial statements other than the additional disclosures required.

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 CRISIS

The weakened world economy that existed in the last half of 2008 has continued through the first three months of 2009. Liquidity constraints continue to exist within the capital markets of the United States ("U.S.") and around the world. Our ability to raise 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 intend to move forward with our planned internal growth projects, although our capital spending, particularly on the natural gas side of our business, will be tempered to reduce our capital raising requirements. In the near-term, we will focus on maintaining sufficient liquidity to fund our growth programs, see "Liquidity and Capital Resources." Maintaining 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, 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 month periods ended March 31, 2009 and 2008.

	For the three months ended March 31,	
	2009	**2008**
	(unaudited; in millions)	
Operating Income		
Liquids	$102.2	$ 61.6
Natural Gas	17.2	72.2
Marketing	3.9	0.5
Corporate, operating and administrative	(0.9)	(2.0)
Total Operating Income	122.4	132.3
Interest expense	51.3	27.6
Other expense	0.5	0.3
Income tax expense	2.0	1.3
Net Income	$ 68.6	$103.1

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 Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), 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

Operating income from our Liquids segment increased by $40.6 million to $102.2 million for the three months ended March 31, 2009, from the $61.6 million generated during the same period of 2008. The operating income of our Liquids segment was affected by the following:

- Tariff increases that went into effect in April and July 2008 and January 2009, which include increases associated with the first stage of our Southern Access Expansion and the Phase V expansion of our North Dakota system; and
- Additional revenue we recorded in the first quarter of 2009 resulting from our joint tolling arrangement with Mustang Pipe Line, LLC ("Mustang").

The above increases to operating income were partially offset by:

- Reduced delivery volumes on our Lakehead system resulting from the line-filling of the first stage of our Southern Access Expansion in March 2009;
- Lower prices associated with the allowance oil we receive coupled with unfavorable oil measurement adjustments; and
- Increased workforce-related and other operating costs.

Natural Gas

Operating income from our Natural Gas segment decreased by $55.0 million to $17.2 million for the three months ended March 31, 2009, from the $72.2 million for the same period of 2008. The following factors affected the operating income of our Natural Gas business:

- $10.0 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 gains of $26.8 million for the same period of 2008;
- Lower margins resulting from the overall deterioration of natural gas and NGL prices as compared with the first three months of 2008;
- Volume growth associated with the completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project; and
- Increased workforce-related costs coupled with variable operating and administrative cost increases associated with our system growth.

Marketing

Operating income from our Marketing segment increased by $3.4 million to $3.9 million for the three months ended March 31, 2009 compared to $0.5 million in the same period in 2008. The operating results of our Marketing segment for the three months ended March 31, 2009 were positively affected by $6.0 million fewer unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 as compared with the same period in 2008. Partially offsetting the lower unrealized non-cash, mark-to-market losses were $2.9 million of non-cash charges for the three months ended March 31, 2009 we recorded to reduce the cost basis of our natural gas inventory to fair market value. The non-cash, mark-to-market losses and revaluation charges during the three months ended March 31, 2009 resulted from wider transportation differentials and the declines in natural gas prices, respectively.

Derivative Transactions and Hedging Activities

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133 and the guidance set forth in SFAS No. 157, *Fair Value Measurement* ("SFAS No. 157"). 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. Based on our risk management policies, all of our derivative 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.

In our natural gas business, the forward prices for natural gas at December 31, 2008 were greater than these prices at March 31, 2009, producing unrealized, non-cash mark-to-market net losses of $10.0 million from the derivative instruments we use to fix the price of the natural gas we purchase for processing. These net losses were partially offset by unrealized non-cash mark-to-market net gains resulting from modestly lower forward NGL prices at March 31, 2009 as compared with the prices at December 31, 2008, associated with the derivatives we use to hedge the sales prices of a portion of the NGLs we derive from processing natural gas. Comparatively, at December 31, 2007 the forward prices for natural gas were lower than the prices at March 31, 2008, which produced $26.8 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 resulting from modestly higher forward and daily NGL prices at March 31, 2008 as compared with the prices at December 31, 2007, associated with the derivatives we use to hedge the sales prices of a portion of the NGLs we derive from processing natural gas.

In our marketing business, the lower forward prices for natural gas at March 31, 2009 in relation to the prices at December 31, 2008, produced unrealized non-cash mark-to-market net losses of $6.9 million in our portfolio of derivative instruments we use to fix the price of natural gas we purchase for storage activities. Partially offsetting net losses associated with the derivative instruments we use for our storage activities, were gains resulting from narrowing basis differentials (the relative difference in the price we pay to purchase natural gas at one location and the price we receive from the sale of natural gas to our customers at another location), on derivative instruments we use to hedge our transportation activities. For the same period of 2008, the forward prices of natural gas were higher at March 31, 2008 than the prices at December 31, 2007, producing $12.9 million of losses on our derivative instruments.

We intend to continue using derivative instruments in our Natural Gas and Marketing businesses to hedge our portfolio of natural gas and NGLs because of the benefit we derive from reducing the volatility in our cash flows. Our continued use of derivative instruments is likely to result in additional unrealized, non-cash gains and losses in the future. We expect the net mark-to-market losses to be offset when the related physical transactions are settled.

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" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ (0.2)	$ (1.8)
Non-qualified hedges	(9.8)	28.6
Marketing		
Non-qualified hedges	(6.9)	(12.9)
Commodity derivative fair value gains (losses)	(16.9)	13.9
Corporate		
Non-qualified interest rate hedges	—	(0.2)
Derivative fair value gains (losses)	$(16.9)	$ 13.7

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

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

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions)	
Operating Results		
Operating revenues	$219.4	$157.0
Operating and administrative	54.4	37.5
Power	33.4	38.3
Depreciation and amortization	29.4	19.6
Operating expenses	117.2	95.4
Operating Income	$102.2	$ 61.6
Operating Statistics		
Lakehead system:		
United States[(1)]	1,265	1,257
Province of Ontario[(1)]	354	380
Total Lakehead system deliveries[(1)]	1,619	1,637
Barrel miles (billions)	105	109
Average haul (miles)	720	729
Mid-Continent system deliveries[(1)]	239	251
North Dakota system:		
Trunkline	108	103
Gathering	6	5
Total North Dakota system deliveries[(1)]	114	108
Total Liquids Segment Delivery Volumes[(1)]	1,972	1,996

(1) Average barrels per day ("Bpd") in thousands.

Three months ended March 31, 2009 compared with three months ended March 31, 2008

Our Liquids segment accounted for $102.2 million of operating income during the three months ended March 31, 2009, an increase of $40.6 million from the $61.6 million generated during the same period in 2008. The favorable results are primarily attributable to tariff increases that went into effect during 2008 and 2009 and additional revenue that was recognized in the first quarter of 2009 as a result of a joint tariff invoicing error that occurred in prior periods, partially offset by higher operating and administrative costs, and depreciation.

Operating revenue for the three months ended March 31, 2009 increased by $62.4 million to $219.4 million from $157 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;
- Additional revenue we recognized in the first quarter of 2009 resulting from our joint tolling arrangement with Mustang; and
- Additional contract storage fees revenue generated by our Mid-Continent storage terminal system.

These increases in operating revenue were partially offset by the following:

- Lower delivered volumes on our Lakehead system resulting from the line-filling of the first stage of our Southern Access Expansion; and
- 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 $55.5 million of additional operating revenue. We filed and implemented new tariff rates in 2008 on our Lakehead system, effective April 1, 2008, to reflect the completion of four projects: (1) the Southern Access mainline expansion, (2) two Superior terminal tank projects, (3) two Griffith terminal tank projects and (4) the Clearbrook Manifold project. 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. Additionally, 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. We expect our transportation revenues to grow over the rest of 2009 due to the Southern Access Surcharge that became effective April 1, 2009 which include rates related to our recently completed Stage 2 Southern Access Expansion. Additional discussion of these tariffs is provided below under the section labeled *Regulatory Matters—FERC Transportation Tariffs—Liquids.*

During the three months ended March 31, 2009, we recorded approximately $13.8 million of previously unbilled operating revenues associated with our Lakehead system that relate to incorrectly invoicing shippers from October 2005 through December 2008. Enbridge Energy, Limited Partnership (the "Enbridge Partnership"), our wholly-owned subsidiary, is party to a joint tariff agreement with Mustang, a business partially-owned by Enbridge Inc. ("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 their pipeline system to markets south of Chicago. The joint tariff agreement in place with Mustang allows for shippers on our Lakehead system to reach markets downstream of Chicago by providing committed shippers with a discounted transportation rate for their commitments to transport crude oil exiting our Lakehead system in the Chicago region through 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 did not record approximately $13.8 million of operating revenues on our Lakehead system from October 2005 through December 2008. The unrecorded revenues 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 three months ended March 31, 2009.

Also contributing to the increase in revenues for the three months ended March 31, 2009, was an approximately $3.2 million increase in contract storage and spot storage fees generated by our Mid-Continent system derived primarily from increased spot storage deals.

Average delivery volumes on our Lakehead system decreased approximately 1.1 percent, to 1.619 million Bpd during the three months ended March 31, 2009 from 1.637 million Bpd during the same period in 2008, contributing a decrease of $2.5 million to operating revenue. The decrease in average deliveries on our Lakehead system is primarily the result of the line-filling of the first stage of our Southern Access expansion that occurred in March 2009. Filling the pipeline reduced deliveries for the three months ended March 31, 2009 by approximately 27,000 Bpd, since the crude oil shipped by customers on our Southern Access pipeline is not delivered. We expect volumes to increase in the second half of the year after we have completed line-filling the Southern Access pipeline. Further compounding the reduced delivery volumes was a decrease in crude oil supplies from upstream production facilities of the oil sands in Alberta, Canada, ("Alberta Oil Sands") due to delays in upgrader projects and turnaround maintenance.

Our transportation tariff allows 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 March 31, 2009 are substantially lower than the average prices for the same period of 2008. For example, the average price of West Texas Intermediate crude oil has decreased approximately 56 percent for the three months ended March 31, 2009 as compared with the same period in 2008. As a result of the decrease in crude oil prices, we experienced an approximate $7.6 million decrease in allowance oil revenues.

Operating and administrative expenses for the Liquids segment increased $16.9 million for the three months ended March 31, 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 growing systems;
- Unfavorable oil measurement adjustments as described below, primarily attributable to physical and revaluation adjustments;
- Favorable settlements of property tax assessments that were realized during the three months ended March 31, 2008, which were not present for the same period in 2009; and
- Higher operating costs mainly attributable to the Line 13 lease for $2.3 million for the quarter as discussed in Item 1. Financial Statements—*Note 8—Related Party Transactions—Line 13 Exchange and Lease*, which will be recovered through a tolling surcharge on our Lakehead system with the net effect on our cash flow expected to approximate zero beginning April 1, 2009.

Oil measurement adjustments occur as part of the normal operations associated with our Liquids systems. 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 $4.9 million in the three months ended March 31, 2009, compared with the same period in 2008, predominantly due to the lower delivery volumes transported on our systems.

The increase in depreciation expense of $9.8 million is attributable to the additional assets we have placed in service during the last three quarters of 2008, primarily the Southern Access Expansion stage one assets that we placed in service during the second quarter of 2008.

Other Matters

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C. ("Southern Lights"), a wholly-owned subsidiary of our general partner, we completed the transfer of a 156-mile section of pipeline from our Lakehead system ("Line 13") to Southern Lights, in exchange for a newly constructed light sour pipeline. 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 back 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 Inc. ("Enbridge Pipelines"), a subsidiary of Enbridge, 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 will be recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow is expected to approximate zero. The exchange resulted in a $160.7 million increase in "Property, plant and equipment" and the capital account of our general partner included in "Partners' capital" on our March 31, 2009 consolidated statement of financial position for the $165.7 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. The light sour line is newer and has a slightly higher capacity than the Line 13 pipeline, 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 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 U.S. 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 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 ("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. We expect to begin construction on the U.S. leg of the project in mid-2009. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. We anticipate that the first full year EBITDA resulting from the completion of this project will approximate $170 million.

North Dakota

The United States Geological Survey, or USGS, completed an assessment of the undiscovered oil and associated natural gas resources of the Upper Devonian—Lower Mississippi Bakken formation in the U.S. portion of the Williston Basin and has determined there to be 3.0 to 4.3 billion barrels of technologically recoverable oil with potential reserves substantially higher than these amounts. Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. As a result, 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 ("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 ("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 and Other Projects

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 will be placed into service upon the completion of the Southern Access Stage 2 linefill, which is scheduled for 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.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and the Canadian Association of Petroleum Producers ("CAPP") for its 36-inch diameter Southern Access Extension pipeline from Flanagan to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. This project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. Project timing is being re-evaluated as a result of delays in the regulatory process and the May 2008 denial by the FERC of Enbridge's October 2007 filing seeking a declaratory order of the tariff rate structure for the pipeline. Enbridge remains committed to meeting the shippers' need for transportation of crude oil from the Chicago area to the Patoka hub and is working with customers to reposition the project in a manner that is commercially appropriate for the market and includes a tolling structure acceptable to the FERC.

Southern Lights

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago to Edmonton, Alberta, Canada to meet the growing demand for crude oil diluent required to transport the heavy oil and bitumen (a thick, tar-like form of oil) being produced in increasing volumes from the Alberta Oil Sands. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line. The project involves the exchange of a 156-mile section of pipeline we own, referred to as Line 13, for a similar section of a new pipeline constructed as part of the project. In addition, this project involves a reconfiguration of our light crude mainline system, which will provide an additional 45,000 Bpd of effective capacity at no cost to us.

In February 2008, the National Energy Board ("NEB") issued its approval and, in May 2008, the Canadian Government also issued its Governor In Council ("GIC") approval for the Canadian portion of the Southern Lights project, which allowed construction to commence. Enbridge has filed the majority of necessary applications for the U.S. portion of the project with U.S. federal and state regulatory agencies. These regulatory processes are expected to be resolved in the first half of 2009, enabling construction for the remaining U.S. portion of the project to commence in mid-2009. Enbridge filed a petition for declaratory order with the FERC setting forth the rate structure for establishing tolls and the proposed swap of Line 13 discussed above, which the FERC approved in late December 2007. This project is expected to be placed in service in 2010.

United States Gulf Coast Joint Initiative

In August 2008, Enbridge and BP Pipelines (North America) Inc. ("BP") announced they are currently developing an initiative to deliver incremental volumes of Canadian crude oil to the U.S. Gulf Coast. The initiative, as envisioned, involves the reversal of the BP #1 pipeline system between Flanagan and Cushing, as well as the construction of a new pipeline between Cushing and Houston, Texas. The scope of the project provides for a pipeline system with over 150,000 Bpd of new capacity between Flanagan and Cushing and approximately 250,000 Bpd of capacity between Cushing and Houston. Enbridge is currently working with BP to develop commercial terms to present to a targeted list of potential shippers to solicit binding support prior to launching an open season in 2009. The target in-service date for this pipeline system is late 2012.

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 ("MMBtu/d") for the periods presented:

	For the three months ended March 31,	
	2009	**2008**
	(unaudited; in millions)	
Operating revenues	$ 602.1	$ 1,164.0
Cost of natural gas	470.0	987.8
Operating and administrative	80.6	74.9
Depreciation and amortization	34.3	29.1
Operating expenses	584.9	1,091.8
Operating Income	$ 17.2	$ 72.2
Operating Statistics (MMBtu/d)		
East Texas	1,631,000	1,396,000
Anadarko	597,000	616,000
North Texas	408,000	367,000
MidLa	100,000	125,000
AlaTenn	53,000	63,000
Bamagas	142,000	102,000
Other major intrastates[(1)]	312,000	282,000
Total[(2)]	3,243,000	2,951,000

(1) We have included in the table above average daily volumes of 105,000 MMBtu/d and 55,000 MMBtu/d related to our Quivira system for the three month periods ended March 31, 2009 and 2008, respectively.

(2) In January 2009, we sold the member interests of our UTOS, which contributed average daily volumes of approximately 196,000 MMBtu/d for the three months ended March 31, 2008 and have been excluded.

Three months ended March 31, 2009 compared with the three months ended March 31, 2008

Our Natural Gas segment contributed $17.2 million of operating income for the three months ended March 31, 2009, a decrease of $55.0 million from the $72.2 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 March 31, 2009 as compared with the same period of 2008:

- $10.0 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 gains of $26.8 million for the same period of 2008;
- The overall erosion in prices for NGLs, natural gas and condensate decreased the value of these commodities which we receive in-kind as payment for our services under some of our contract structures;
- Volume growth associated with the completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project; and
- Increased workforce related costs and depreciation associated with our system growth.

The operating income of our Natural Gas segment for the three months ended March 31, 2009 was negatively impacted by unrealized non-cash, mark-to-market net losses of $10.0 million, representing a decrease of $36.8 million from the $26.8 million of gains we recorded for the same period of 2008. The forward prices for natural gas at December 31, 2008 were higher than the prices at March 31, 2009, producing unrealized non-cash mark-to-market net losses of $10.0 million from the derivative instruments we use to fix the price of the natural gas we purchase for processing. These net losses were partially offset by unrealized non-cash mark-to-market net gains resulting from modestly lower forward and daily NGL prices at March 31, 2009 as compared with the prices at December 31, 2008, associated with the derivatives we use to hedge the sales prices of a portion of the NGLs we derive from processing natural gas. Comparatively, at December 31, 2007 the forward prices for natural gas were lower than the prices at March 31, 2008, which produced $26.8 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 resulting from modestly higher forward NGL prices at March 31, 2008 as compared with the prices at December 31, 2007, associated with the derivatives we use to hedge the sales prices of a portion of the NGLs we derive from processing natural gas. We expect the net mark-to-market losses to be offset when the related physical transactions are settled. 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 months ended March 31, 2009 and 2008:

Derivative fair value gains (losses)	For the three months ended March 31, 2009	2008
	(unaudited; in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ (0.2)	$ (1.8)
Non-qualified hedges	(9.8)	28.6
Derivative fair value gains (losses)	$(10.0)	$26.8

We are exposed to fluctuations in commodity prices in the near term on approximately 20 to 40 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 three months periods ended March 31, 2009 and 2008, NGL and condensate prices increased while natural gas prices decreased, creating a favorable pricing environment for the processing of NGLs and condensate. However, due to the overall decline in commodity prices from the first three months of 2008 to the same period in 2009, the 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, which we completed at the end of 2008. With the expansions we completed in 2008 that were not in-service for the first three months of 2008, we have been able to provide additional gathering, processing, treating and transportation services for our 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 March 31, 2009, natural gas production increased relative to the same period in 2008, and was flat relative to the fourth quarter of 2008. Due to the significant decline in natural gas prices over the past several months, producers have slowed down production relative to activity levels present throughout 2008. Our growth may be tempered by the reduced production of natural gas by 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 raise the necessary capital to engage in new projects, which could decrease the amount of new natural gas production in the areas we serve.

A variable element of our Natural Gas segment's operating income is derived from processing natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems. Operating income derived from keep-whole processing arrangements for the three months ended March 31, 2009 was $11.9 million, representing a decrease of $18.2 million, or 60 percent, from the $30.1 million we produced for the same period in 2008. We have experienced a trend of replacing or renegotiating some of our existing keep-whole contracts with percentage of liquids, or POL, type contracts and other similar arrangements. This trend should reduce our exposure to the commodity price spread between natural gas and NGLs for the portion of the operating income we derive from processing natural gas under keep-whole arrangements.

As a result of the price declines in daily natural gas prices in the first three months of 2009, we recorded $1.8 million of revaluation losses with respect to our in-kind natural gas imbalances. The declines in natural gas prices also required us to recognize $0.4 million of charges to reduce the cost basis of our natural gas inventories to net realizable value. The average daily price of natural gas as published by Platt's Gas Daily for Henry Hub was approximately $3.96 per MMBtu for the month of March 2009, a 32% decline from $5.79 per MMBtu for the month of December 2008. Similar revaluation losses and charges to our natural gas inventories were not recognized in the first three months of 2008.

Operating and administrative costs of our Natural Gas segment were $5.7 million greater for the three months ended March 31, 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.

Depreciation expense for our Natural Gas segment was higher for the three months ended March 31, 2009 as compared to the same period in 2008, as a result of the capital projects completed and placed into service throughout 2008.

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. Construction is progressing on schedule and we expect to complete this project in the second quarter of 2009 at an approximate cost of $60 million. Commercial terms for this project predominately involve firm volume commitments from customers.

Enbridge Projects

LaCrosse Pipeline

Enbridge is conducting a non-binding open season for an interstate natural gas pipeline 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. The non-binding open season will run through May 15, 2009.

Marketing

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

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions)	
Operating revenues	$638.2	$1,114.3
Cost of natural gas	632.1	1,111.0
Operating and administrative	1.8	2.3
Depreciation and amortization	0.4	0.5
Operating expenses	634.3	1,113.8
Operating Income	$ 3.9	$ 0.5

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.

Three months ended March 31, 2009 compared with three months ended March 31, 2008

The operating income of our Marketing segment increased to $3.9 million for the three months ended March 31, 2009 from $0.5 million for the corresponding period in 2008. Included in operating income for the first quarter of 2009 are approximately $6.9 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with the $12.9 million of unrealized mark-to-market losses for the same period of 2008. During the three months ended March 31, 2009, increases in the forward and daily market prices of natural gas produced non-cash, mark-to-market losses in our portfolio of derivative instruments that were below those produced during the same period of 2008. We expect these net mark-to-market losses to be offset when the related physical transactions are settled.

Operating income for the three months ended March 31, 2009 was also negatively affected by non-cash charges of $2.9 million we recorded to reduce the cost basis of our natural gas inventory to fair market value at March 31, 2009, where no such charge existed for the same period in 2008. Natural gas prices continued to decline during the quarter from the record highs experienced in July 2008. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

Corporate

Interest expense was $51.3 million for the three months ended March 31, 2009, compared with $27.6 million 2008. The increases are primarily the result of higher weighted average debt balance associated with the following debt issuances:

- $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 rate is 7.2% and 6.2% for the three months ended March 31, 2009 and 2008, respectively.

Further contributing to the increase in interest expense is the $6.2 million decrease in interest capitalized to our construction projects in the three months ended March 31, 2009 as compared to the same period in 2008. Our interest cost is comprised of the following:

	For the three months ended March 31,	
	2009	2008
	(unaudited; in millions)	
Interest expense	$51.3	$27.6
Interest capitalized	12.9	19.1
Interest cost incurred	$64.2	$46.7

LIQUIDITY AND CAPITAL RESOURCES

Impact of Current Economic Crisis

The economic recession that existed in the last half of 2008 has persisted in the first three months of 2009. Liquidity constraints continue to exist within the capital markets of the United States and around the world. As evidenced by our December 2008 debt offering and the new credit facilities we entered into in April 2009, we have the ability to access the capital markets; however, the prices at which we can access capital are substantially higher than the prices we incurred for similar offerings in recent years. Our cost of 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.

Our near-term focus is to ensure we have sufficient liquidity to fund our growth programs and maintain our credit rating, while continuing the present distribution rate to our unitholders. The current economic crisis has created a challenging operating environment for us to maintain our liquidity and operating cash flows at levels consistent with the recent past while maintaining the present distribution rate to our unitholders.

We intend 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 the incremental benefits expected to accrue to our unitholders from our expansion activities are likely to be decreased by substantial cost of capital increases during this period.

At March 31, 2009, we have in excess of $1.6 billion of liquidity to meet our ongoing operational, investment and finance needs, which does not include the $350 million of 364-day credit facilities we entered into in April 2009.

	(in millions)
Availability under Credit Facility	$ 941.4
Available under Enbridge (U.S.) Credit Agreement	500.0
Cash and cash equivalents	174.4
Total	$1,615.8

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 ("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. ("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

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. We currently are 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 are now utilizing our Credit Facility as our primary source of liquidity. We use our Credit Facility primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions. In addition to our Credit Facility we have available a 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 ("Lehman BB"), a subsidiary of Lehman Brothers Holdings, Inc. ("Lehman"), as a party to the Credit Facility following Lehman's filing for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code in September 2008. Lehman BB ceased to honor its commitments under the Credit Facility of $82.5 million; effectively reducing the amounts available to us under our Credit Facility to $1,167.5 million. 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 March 31, 2009, we had $220.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.83% and letters of credit totaling $6.1 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 March 31, 2009, we could borrow $941.4 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	(220.0)
Balance of letters of credit outstanding	(6.1)
Total amount we could borrow at March 31	$ 941.4

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 amounts due. During the three month periods ended March 31, 2009 and 2008, we net settled borrowings of approximately $240 million and $390 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. ("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 March 31, 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 March 31, 2009, we had approximately $281.1 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 $5.7 million for the three months ended March 31, 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 $212.9 million, including $14.8 million on core maintenance activities, for the three months ended March 31, 2009.

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 March 31, 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 March 31, 2009	Estimated Incremental Capacity Oil	Expected Completion
	(in billions)		(Kbpd)[1]	
Southern Access expansion (Lakehead)	$2.1	$2.0	400	2009
Alberta Clipper	1.2	0.2	450	Mid-2010
North Dakota Phase VI expansion	0.2	—	50	Early 2010
Total	$3.5	$2.2	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 year and a half due to our Alberta Clipper and North Dakota projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding 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. 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 March 31, 2009:

	Notional	2009	2010	2011	2012	2013	Total
		(dollars, in millions)					
Swaps							
Natural gas[1]	245,028,703	$(36.6)	$(24.2)	$(24.9)	$ (6.7)	$2.0	$(90.4)
NGL[2]	5,836,697	43.5	27.4	12.5	14.4	—	97.8
Crude[2]	1,623,000	3.9	4.8	1.9	0.9	3.4	14.9
Options-calls							
Natural gas—written[1]	1,005,000	(0.1)	(0.6)	(0.8)	—	—	(1.5)
Options-puts							
Natural gas—written[1]	137,345	(0.5)	—	—	—	—	(0.5)
Natural gas—purchased[1]	1,100,000	0.1	—	—	—	—	0.1
NGL[2]	888,332	6.7	5.9	2.8	4.5	—	19.9
Totals		$ 17.0	$ 13.3	$ (8.5)	$13.1	$5.4	$ 40.3

(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 three months ended March 31, 2009 was $275.2 million, a decrease of $1.0 million from the $276.2 million generated during the same period in 2008. The decrease in operating cash flow is directly attributable to lower net income resulting from significant declines in commodity prices from historic highs reached in July 2008, which also reduced cash flows associated with changes in our working capital accounts for the three months ended March 31, 2009 as compared with the same period of 2008. Net cash provided by operating activities also decreased due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $216.3 million less in our investing activities during the three months ended March 31, 2009 in relation to the same period in 2008. The decrease is primarily attributable to the $210.9 million reduction of amounts spent in the first three 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 our Clarity project and the first stage of our Southern Access expansion project.

Financing Activities

Net cash used in financing activities during the three months ended March 31, 2009 was $215.0 million, compared with net cash provided by financing activities of $241.1 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 in the first three months of 2009 when compared to the same period in 2008 and our repayment of the $175 million Senior Notes that occurred in the first quarter of 2009. Additionally, the change in cash associated with financing activities for the three months ended March 31, 2009 as compared with the same period of 2008 is attributable to the following:

- $27.2 million more distributions to our partners for the first three months of 2009 due to a greater number of units outstanding, a higher distribution level and higher incentive distribution payments to our general partner.

The decrease in cash raised from both debt repayment and distributions to partners is partially offset by the $53.2 million of net borrowings on our Credit Facility.

For the three months ended March 31, 2009, we had gross borrowings of $530.1 million under our Credit Facility and gross repayments of $476.8 million, including $240.0 million of non-cash borrowings and repayments.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

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.

Distribution to Partners

On April 30, 2009, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2009. The distribution will be paid to unitholders of record as of May 7, 2009, of our available cash of $129.2 million at March 31, 2009, or $0.990 per common unit. Of this distribution, $93.3 million will be paid in cash, $15.1 million will be distributed in i-units to our i-unitholder, $20.1 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.

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

Interim Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued FASB Staff Position (“FSP”) FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. The objective of the FSP is to increase the frequency of similar types of disclosures regarding the fair values of financial instruments to improve the transparency of information for financial statement users. The provisions require disclosure of the following on both an interim and annual basis are as follows:

- The fair value of all financial instruments, whether or not recognized in the statement of financial position;
- Fair value information disclosed in the notes shall be presented together with the related carrying amount in a form that makes it clear whether the fair value and carrying amount represent assets or liabilities and how the carrying amount relates to what is reported in the statement of financial position; and
- The method(s) and significant assumptions used to estimate the fair value of financial instruments.

The FSP is effective for interim and annual reporting periods ending after June 15, 2009, with earlier application of the provisions of the FSP permitted. The FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, the FSP requires comparative disclosures only for periods ending subsequent to the initial adoption date. We did not adopt the provisions of this pronouncement early and we do not expect our adoption of the FSP in the second quarter of 2009 to have a significant effect on our financial statements other than the additional disclosures required.

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 commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative 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. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

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

	At March 31, 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	18,906,195	$ 3.58	$ 7.06	$ 0.4	$(70.5)	$ 2.5	$(56.0)
	NGL	132,950	30.16	63.63	—	(4.4)	—	(6.5)
Receive fixed/pay variable . . .	Natural Gas	16,567,705	6.02	4.04	37.9	(4.8)	38.7	(19.6)
	NGL	2,937,825	45.82	29.45	47.9	—	70.0	—
	Crude Oil	266,875	69.26	54.97	4.3	(0.4)	5.8	(0.6)
Receive variable/pay variable	Natural Gas	96,573,109	3.73	3.73	7.2	(6.8)	8.9	(12.8)
Options								
Calls (written)	Natural Gas	275,000	4.31	4.32	—	(0.1)	—	(0.6)
Puts (written)	Natural Gas	137,345	3.69	7.28	—	(0.5)	—	—
Puts (purchased)	Natural Gas	370,000	4.56	3.47	0.1	—	—	(1.2)
	NGL	431,000	45.98	32.06	6.7	—	9.3	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed . . .	Natural Gas	4,488,550	$ 5.44	$ 7.34	$ 1.7	$(10.1)	$ 2.5	$ (6.5)
	NGL	165,625	43.73	48.70	0.5	(1.3)	—	(1.3)
Receive fixed/pay variable . . .	Natural Gas	11,636,287	4.64	5.73	5.6	(18.2)	2.2	(27.5)
	NGL	1,513,655	49.12	30.22	28.2	—	28.0	—
	Crude Oil	525,150	71.76	62.68	5.9	(1.1)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	64,508,963	5.58	5.63	0.7	(3.9)	0.8	(3.1)
Options								
Calls (written)	Natural Gas	365,000	4.31	5.93	—	(0.6)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	5.93	3.40	—	—	—	—
	NGL	245,280	56.60	35.80	5.9	—	5.2	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed . . .	Natural Gas	2,944,510	$ 6.25	$ 7.20	$ 2.2	$ (4.9)	$ 2.6	$ (3.4)
	NGL	10,000	51.75	47.67	—	—	—	—
Receive fixed/pay variable . . .	Natural Gas	9,301,675	4.19	6.57	2.0	(23.4)	1.1	(28.1)
	NGL	581,810	55.84	33.64	12.5	—	13.0	(0.3)
	Crude Oil	538,375	71.70	67.62	3.5	(1.6)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.44	6.49	0.4	(1.2)	—	(1.0)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.67	—	(0.8)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	6.67	3.40	—	—	—	—
	NGL	83,220	63.34	30.95	2.8	—	2.7	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed . . .	Natural Gas	941,709	$ 6.80	$ 8.72	$ 0.7	$ (2.4)	$ 0.8	$ (2.1)
	NGL	36,600	31.13	55.58	—	(0.8)	—	(0.9)
Receive fixed/pay variable . . .	Natural Gas	1,456,000	3.57	7.33	—	(5.2)	—	(5.8)
	NGL	458,232	70.56	35.46	15.2	—	15.7	—
	Crude Oil	219,600	74.85	70.36	0.9	—	0.8	—
Receive variable/pay variable	Natural Gas	1,089,000	6.45	6.27	0.2	—	—	—
Options								
Puts (purchased)	NGL	128,832	66.80	33.33	4.5	—	4.4	—
Contracts maturing in 2013								
Swaps								
Receive fixed/pay variable . . .	Natural Gas	730,000	$ 9.83	$ 6.78	$ 2.0	$ —	$ 2.0	$ —
	Crude Oil	73,000	124.05	72.40	3.4	—	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 March 31, 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.

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).

	March 31, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(0.3)	(39.6)
A	43.1	73.3
Lower than A	(0.5)	(1.2)
	42.3	32.5
Credit valuation adjustment	0.3	2.2
Total	$ 42.6	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934, as amended. Our management has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 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 months ended March 31, 2009.

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

The risk factors presented below update and should be considered in addition to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

Our actual construction and development costs could exceed our forecast and our cash flow from construction and development projects may not be immediate, which may limit our ability to maintain or increase cash distributions.

Our strategy contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets. Increased demand for the steel used to fabricate the pipe needed for our construction projects and increased competition for labor has resulted in increased costs for these resources. Additionally, the construction of new assets involves numerous regulatory, environmental, legal, political and operations risks that are difficult to predict and beyond our control. As a result, we may not be able to complete our projects at the costs currently estimated or within the time periods we have projected. If we experience material costs overruns, we will have to finance these overruns using one or more of the following methods:

- Using cash from operations;
- Delaying other planned projects;
- Incurring additional indebtedness;
- Issuing additional equity;
- Selling non-core assets; or
- Entering into a partnership or joint venture arrangement.

Any or all of these methods may not be available when needed or may adversely affect our future results of operations and cash flows.

Our revenues and cash flows may not increase immediately on our expenditure of funds on a particular project. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers begin using the systems. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays, or other factors, we may not meet our obligations as they become due and we may need to reduce or reprioritize our capital budget, sell non-strategic assets, access the capital markets or reassess our level of distributions to unitholders to meet our capital requirements.

Our ability to access the credit and capital markets on attractive terms to obtain funding for our capital projects may be limited due to the deterioration of these markets.

We expect to make significant expenditures for the construction of additional crude oil transportation infrastructure over the next year and a half. Our ability to fund these expenditures is dependent on our ability to access the capital necessary to finance the construction of these facilities. Domestic and global financial markets and economic conditions have been, and continue to be, weak and volatile and have contributed significantly to a substantial deterioration in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and the re-pricing of credit risks have made, and likely will continue to make, it difficult to obtain funding for our capital needs from the credit and capital markets on terms similar to our recent capital-raising transactions. As a result, we may revise the timing and scope of these projects as necessary to adapt to existing markets and economic conditions.

In particular, the cost of raising funds in the debt and equity capital markets has increased while the availability of funds from those markets has diminished. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining funds from the credit markets has increased as many lenders have increased interest rates, enacted tighter lending standards and reduced, and in some cases ceased to provide, funding to borrowers.

Due to the recent downturn in the financial markets, including the issues surrounding the solvency of many financial institutions and the recent failure, combinations and announced combinations of several financial institutions, our ability to obtain capital from our Second Amended and Restated Credit Facility (the "Credit Facility") may be impaired. For example, following Lehman Brothers Holdings Inc. ("Lehman") filing a petition under Chapter 11 of the U.S. Bankruptcy Code, Lehman Brothers Bank FSB ("Lehman BB"), a subsidiary of Lehman and a committed lender under our Credit Facility, could not honor its commitments under our Credit Facility of $82.5 million. As a result, the administrative agent of our Credit Facility 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 BB. We amended our Credit Facility in March 2009 to remove Lehman BB as a lender, which reduced the aggregate amount available to us under the Credit Facility to $1,167.5 million. We may be unable to use the full borrowing capacity under our Credit Facility if any of the remaining committed lenders are unable or unwilling to fund their portion of any funding request we make under our Credit Facility.

Due to these factors, we cannot be certain that the funding for our capital needs will be available from the credit and capital markets if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions and construction projects, otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Item 6. Exhibits

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: May 5, 2009

By: /s/ STEPHEN J. J. LETWIN
Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)

Date: May 5, 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 the Fourth Amended and Restated Agreement of the 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*+	Executive Employment Agreement, dated January 9, 2008, between Al Monaco, as Executive, and Enbridge Inc., as Corporation.
10.2*	First Amendment to Second Amended and Restated Credit Agreement, dated March 27, 2009 among Enbridge Energy Partners, L.P., as Borrower, Bank of America, N.A., as administrative agent, and the lenders party thereto.
10.3*	Credit agreement dated April 9, 2009, between the Partnership, as Borrower, and Barclays Bank PLC, as Trustee.
10.4*	Credit agreement dated April 9, 2009, between the Partnership, as Borrower, and Enbridge (U.S.) Inc., as Trustee.
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.