
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 September 30, 2008

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
(State or other jurisdiction of
incorporation or organization)

39-1715850
(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 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 ☐ Smaller reporting company ☐
(Do not check if a 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 59,838,834 Class A common units outstanding as of October 31, 2008.

ENBRIDGE ENERGY PARTNERS, L.P.

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1.	Financial Statements	
	Consolidated Statements of Income for the three and nine month periods ended September 30, 2008 and 2007	3
	Consolidated Statements of Comprehensive Income for the three and nine month periods ended September 30, 2008 and 2007	4
	Consolidated Statements of Cash Flows for the nine month periods ended September 30, 2008 and 2007	5
	Consolidated Statements of Financial Position as of September 30, 2008 and December 31, 2007	6
	Notes to Consolidated Financial Statements	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	22
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	46
Item 4.	Controls and Procedures	48

PART II. OTHER INFORMATION

Item 1.	Legal Proceedings	49
Item 1A.	Risk Factors	49
Item 6.	Exhibits	50
Signatures	51
Exhibits		

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, 2007 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

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions, except per unit amounts)			
Operating revenue	\$2,812.7	\$1,710.9	\$8,180.2	\$5,162.3
Operating expenses				
Cost of natural gas (Notes 10 and 11)	2,407.5	1,430.8	7,120.6	4,390.7
Operating and administrative	139.9	103.8	378.4	306.6
Power	35.0	29.7	104.6	87.1
Depreciation and amortization	58.6	45.0	163.1	121.3
	<u>2,641.0</u>	<u>1,609.3</u>	<u>7,766.7</u>	<u>4,905.7</u>
Operating income	171.7	101.6	413.5	256.6
Interest expense	50.7	23.4	129.7	70.2
Other income	0.3	0.4	2.5	2.3
Income before income tax expense	121.3	78.6	286.3	188.7
Income tax expense	1.9	1.3	5.0	3.7
Net income	<u>\$ 119.4</u>	<u>\$ 77.3</u>	<u>\$ 281.3</u>	<u>\$ 185.0</u>
Net income allocable to limited partner units (Note 2)	<u>\$ 105.3</u>	<u>\$ 67.9</u>	<u>\$ 245.5</u>	<u>\$ 158.6</u>
Net income per limited partner unit (basic and diluted) (Note 2)	<u>\$ 1.09</u>	<u>\$ 0.75</u>	<u>\$ 2.58</u>	<u>\$ 1.87</u>
Weighted average limited partner units outstanding	<u>96.9</u>	<u>90.0</u>	<u>95.3</u>	<u>84.8</u>

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

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

	Three months ended September 30,		Nine months ended September 30,	
	<u>2008</u>	<u>2007</u>	<u>2008</u>	<u>2007</u>
	(unaudited; in millions)			
Net income	\$119.4	\$77.3	\$281.3	\$185.0
Other comprehensive income (loss), net of tax benefit (expense) of \$(1.5), \$0, \$(0.4) and \$0.4 (Notes 10 and 11) . .	<u>257.1</u>	<u>(1.6)</u>	<u>66.6</u>	<u>(36.6)</u>
Comprehensive income	<u>\$376.5</u>	<u>\$75.7</u>	<u>\$347.9</u>	<u>\$148.4</u>

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

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

	Nine months ended September 30,	
	2008	2007
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	\$ 281.3	\$ 185.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	163.1	121.3
Derivative fair value (gains) losses (Notes 10 and 11)	(17.5)	17.4
Inventory market price adjustments (Note 4)	8.3	4.5
Other	20.1	(2.0)
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	(49.2)	42.3
Due from General Partner and affiliates	2.1	2.5
Accrued receivables	21.1	116.2
Inventory (Note 4)	(98.6)	(13.6)
Current and long term other assets (Notes 10 and 11)	(9.1)	(5.4)
Due to General Partner and affiliates (Note 8)	35.4	39.1
Accounts payable and other (Notes 3, 10 and 11)	(10.5)	(5.9)
Accrued purchases	78.1	(116.8)
Interest payable	55.9	28.9
Property and other taxes payable	14.8	5.3
Settlement of interest rate derivatives (Note 11)	(22.1)	(0.9)
Net cash provided by operating activities	<u>473.2</u>	<u>417.9</u>
Cash used in investing activities		
Additions to property, plant and equipment	(1,000.2)	(1,428.4)
Changes in construction payables	(56.0)	56.4
Changes in restricted cash (Note 3)	(10.0)	—
Other	(13.0)	(2.0)
Net cash used in investing activities	<u>(1,079.2)</u>	<u>(1,374.0)</u>
Cash provided by financing activities		
Net proceeds from unit issuances (Note 7)	221.8	628.8
Distributions to partners (Note 7)	(211.8)	(179.5)
Net borrowings (repayments) under Credit Facility (Note 6)	(13.7)	120.0
Net repayments of commercial paper (Note 6)	(79.4)	(241.2)
Net proceeds from issuances of long-term debt (Note 6)	790.2	592.8
Net cash provided by financing activities	<u>707.1</u>	<u>920.9</u>
Net increase (decrease) in cash and cash equivalents	101.1	(35.2)
Cash and cash equivalents at beginning of year	50.5	184.6
Cash and cash equivalents at end of period	<u>\$ 151.6</u>	<u>\$ 149.4</u>

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

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

	September 30, 2008	December 31, 2007
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	\$ 151.6	\$ 50.5
Restricted cash (Note 3)	10.0	—
Receivables, trade and other, net of allowance for doubtful accounts of \$2.0 in 2008 and \$1.9 in 2007	208.3	157.8
Due from General Partner and affiliates	25.1	27.2
Accrued receivables	577.7	598.8
Inventory (Note 4)	200.9	110.6
Other current assets (Notes 10 and 11)	14.2	14.8
	1,187.8	959.7
Property, plant and equipment, net (Note 5)	6,406.6	5,554.9
Goodwill	256.5	256.5
Intangibles, net	89.7	91.5
Other assets, net (Notes 10 and 11)	40.5	29.0
	<u>\$7,981.1</u>	<u>\$6,891.6</u>
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 8)	\$ 102.3	\$ 45.8
Accounts payable and other (Notes 3, 9, 10 and 11)	271.5	400.4
Accrued purchases	681.9	603.8
Interest payable	76.8	20.9
Property and other taxes payable	37.3	22.5
Current maturities of long term debt	442.8	31.0
	1,612.6	1,124.4
Long term debt (Note 6)	3,163.5	2,862.9
Notes payable to affiliate	130.0	130.0
Other long-term liabilities (Notes 9, 10 and 11)	145.6	202.8
	<u>5,051.7</u>	<u>4,320.1</u>
Commitments and contingencies (Note 9)		
Partners' capital (Note 7)		
Class A common units (59,838,834 at September 30, 2008 and 55,238,834 at December 31, 2007)	1,529.1	1,340.7
Class B common units (3,912,750 at September 30, 2008 and December 31, 2007)	77.6	72.9
Class C units (19,158,153 at September 30, 2008 and 18,073,367 at December 31, 2007)	921.3	874.1
i-units (14,355,600 at September 30, 2008 and 13,564,086 at December 31, 2007) .	557.8	515.3
General Partner	71.4	62.9
Accumulated other comprehensive loss (Notes 10 and 11)	(227.8)	(294.4)
	<u>2,929.4</u>	<u>2,571.5</u>
	<u>\$7,981.1</u>	<u>\$6,891.6</u>

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 September 30, 2008 and December 31, 2007; the results of operations for the three and nine month periods ended September 30, 2008 and 2007; and our cash flows for the nine month periods ended September 30, 2008 and 2007. We derived the Consolidated Statement of Financial Position as of December 31, 2007, from the audited financial statements included in our 2007 Annual Report on Form 10-K. The results of operations for the three and nine month periods ended September 30, 2008, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the 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, 2007.

Comparative Amounts

We have made reclassifications to the amounts reported in our prior year consolidated statement of financial position and our consolidated statements of cash flows to conform to our current year presentation. We reclassified \$2.8 million of “Environmental liabilities” to “Other long-term liabilities” in our December 31, 2007 consolidated statement of financial position. We also reclassified \$1.8 million for changes in “Environmental liabilities” to “Other” under the operating section of our consolidated statements of cash flows. In addition, we reclassified \$3.5 million for changes in the balance of “Current income tax payable” to “Property and other taxes payable” on our consolidated statements of cash flows.

2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after we deduct our allocations to our general partner, Enbridge Energy Company, Inc. (the “General Partner”), by the weighted average number of our limited partner units outstanding. The General Partner’s allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner’s historical

cost basis for assets contributed on formation of the Partnership. We have no dilutive securities. Net income per limited partner unit was determined as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions, except per unit amounts)			
Net income	\$119.4	\$77.3	\$281.3	\$185.0
Allocations to the General Partner:				
Net income allocated to the General Partner	(2.4)	(1.5)	(5.6)	(3.7)
Incentive distributions allocated to the General Partner . . .	(11.7)	(7.9)	(30.1)	(22.6)
Historical cost depreciation adjustments	—	—	(0.1)	(0.1)
	(14.1)	(9.4)	(35.8)	(26.4)
Net income allocable to limited partner units	\$105.3	\$67.9	\$245.5	\$158.6
Net income per limited partner unit (basic and diluted)	\$ 1.09	\$0.75	\$ 2.58	\$ 1.87
Weighted average limited partner units outstanding	96.9	90.0	95.3	84.8

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 in the amounts of approximately \$33.4 million at September 30, 2008 and \$38.5 million at December 31, 2007, are included in “Accounts payable and other” on our consolidated statements of financial position.

In September 2008, following the bankruptcy filing by Lehman Brothers Bank, FSB, as discussed in Note 6, Bank of America, N.A., as administrative agent to our Credit Facility, required us to post a certificate of deposit issued by Bank of America, N.A. for \$10.0 million as collateral against the letters of credit outstanding on our Credit Facility, which we have presented as “Restricted cash” on our consolidated statements of financial position.

4. INVENTORY

Inventory is comprised of the following:

	September 30, 2008	December 31, 2007
	(in millions)	
Materials and supplies	\$ 3.9	\$ 3.9
Liquids inventory	27.7	6.7
Natural gas and natural gas liquids inventory	169.3	100.0
	\$200.9	\$110.6

The cost of natural gas on our consolidated statements of income includes charges totaling \$8.3 million for the three and nine months ended September 30, 2008 and \$4.5 million for the three and nine months ended September 30, 2007 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:

	September 30, 2008	December 31, 2007
	(in millions)	
Land	\$ 17.6	\$ 14.3
Rights-of-way	417.5	345.8
Pipelines	4,167.7	2,703.2
Pumping equipment, buildings and tanks	984.9	854.7
Compressors, meters, and other operating equipment	616.2	536.1
Vehicles, office furniture and equipment	151.9	123.3
Processing and treating plants	297.9	200.4
Construction in progress	943.6	1,813.9
Total property, plant and equipment	7,597.3	6,591.7
Accumulated depreciation	(1,190.7)	(1,036.8)
Property, plant and equipment, net	<u>\$ 6,406.6</u>	<u>\$ 5,554.9</u>

6. DEBT

Credit Facility

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date from April 4, 2012 to April 4, 2013.

At September 30, 2008, we had \$386.2 million outstanding under our Credit Facility at a weighted average interest rate of 3.82% and letters of credit totaling \$101.2 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. The terms of our Credit Facility include commitments from 14 different lenders to borrow up to \$1,250 million, at September 30, 2008. One of the committed lenders to our Credit Facility, Lehman Brothers Bank, FSB (“Lehman BB”), a subsidiary of Lehman Brothers Holdings, Inc. filed for bankruptcy protection under Chapter 11 of the United States (“U.S.”) Bankruptcy Code in September 2008. Lehman BB has commitments of \$82.5 million that we currently cannot access; effectively reducing the amounts available to us under our Credit Facility to \$1,167.5 million. We are working with other financial institutions to assume Lehman BB’s commitment. The remaining lenders under our Credit Facility continue to honor our funding requests.

Excluding the commitments from Lehman BB, at September 30, 2008, we could borrow \$490.1 million under the terms of our Credit Facility, determined as follows:

	September 30, 2008
	(in millions)
Total credit available under Credit Facility	\$1,250.0
Less: Amounts outstanding under Credit Facility	(386.2)
Balance of letters of credit outstanding	(101.2)
Principal amount of commercial paper issuances	(190.0)
Lehman Brothers Bank, FSB commitment	(82.5)
Total amount we could borrow at September 30, 2008	<u>\$ 490.1</u>

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 nine months ended September 30, 2008, we net settled borrowings of approximately \$490 million on a non-cash basis.

Commercial Paper Program

We have a commercial paper program that provides for the issuance of up to \$600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. At September 30, 2008 and December 31, 2007, respectively, we had \$189.5 million and \$268.5 million of commercial paper outstanding, net of unamortized discount of \$0.5 million and \$1.5 million, at weighted average interest rates of 3.19% and 5.36%. At September 30, 2008 we could issue an additional \$410 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

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

Senior Notes

In April 2008, we issued and sold in a private offering \$400 million in principal amount of our 6.5% Notes due April 15, 2018 and \$400 million in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately \$790.2 million after initial purchasers' discounts and payment of offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds which we later used to fund additional expenditures under our capital expansion programs. The Notes do not contain any covenants restricting our issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the Notes is payable April 15th and October 15th of each year and we may redeem the Notes for cash in whole or in part at any time, at our option.

In August 2008, we completed the offers to exchange all of the Notes, which had not been registered under the Securities Act of 1933, as amended (the "Securities Act"), for notes with identical terms that had been registered under the Securities Act.

We received tenders for \$395 million in aggregate principal amount of our outstanding \$400 million of 6.50% Series A Notes due 2018, which we exchanged for \$395 million of our 6.50% Series B Notes due 2018. We also received tenders for all \$400 million in aggregate principal amount of our 7.50% Series A Notes due 2038, which we exchanged for \$400 million of our 7.50% Series B Notes due 2038.

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 nine months ended September 30, 2008:

Distribution Declaration Date	Distribution Payment Date	Record 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
July 28, 2008	August 14, 2008	August 6, 2008	\$0.990	\$108.0	\$13.9	\$18.6	\$0.7	\$74.8
April 28, 2008	May 15, 2008	May 7, 2008	\$0.950	\$102.2	\$13.1	\$17.5	\$0.6	\$71.0
January 28, 2008	February 14, 2008	February 6, 2008	\$0.950	\$ 96.7	\$12.9	\$17.2	\$0.6	\$66.0

⁽¹⁾ During 2008, in lieu of cash distributions, the Partnership issued 791,514 i-units to Enbridge Management.

⁽²⁾ During 2008, in lieu of cash distributions, the Partnership issued 1,084,787 Class C units to our Class C unitholders.

⁽³⁾ The Partnership retains 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.

Issuance of Class A Common Units

On March 3, 2008, we issued and sold 4.6 million Class A common units, including 0.6 million units from the over-allotment option that was exercised by the underwriters, at a price to the public of \$49.00 per unit, for proceeds of approximately \$217.2 million, net of underwriters' discounts, commissions and issuance costs. In addition, our general partner contributed approximately \$4.6 million to us to maintain its two percent general partner interest. We used the proceeds from this offering to partially reduce outstanding commercial paper we issued and amounts we previously borrowed under our Credit Facility to finance a portion of our capital expansion projects. We invested a portion of the proceeds for use in future periods to fund additional expenditures under our capital expansion projects.

8. RELATED PARTY TRANSACTIONS

We, our general partner and Enbridge Pipelines Inc. ("Enbridge Pipelines"), a subsidiary of Enbridge Inc., 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 are constructing the United States portion of the projects and Enbridge Pipelines is constructing the Canadian portion. In September 2008, we acquired for \$21.1 million, approximately 22 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.

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, the 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.

In October of 2008, we received a letter from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") alleging violations of federal pipeline safety regulations and proposing a \$2.4 million fine related to an unexpected release and fire on line 3 of our Lakehead System that occurred during planned maintenance near our Clearbrook, Minnesota, terminal in November 2007. A provision for the amount of the fine has been made in "Short term environmental liabilities."

As of September 30, 2008 and December 31, 2007, we have recorded \$5.7 million and \$3.4 million, respectively, in "Accounts payable and other" and \$3.0 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

We adopted the provisions of Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, or SFAS No. 157, as of January 1, 2008. SFAS No. 157 provides guidance for determining fair value and requires increased disclosure regarding the inputs to valuation techniques used to measure fair value. SFAS No. 157 defines fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. We apply the provisions of SFAS No. 157 to fair values we report for our derivative instruments and annual disclosures associated with the fair values of our outstanding indebtedness.

We utilize a mid-market pricing convention for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. In the case of our liabilities, our nonperformance risk is considered in the valuation, based upon the ratings assigned to our debt obligations by the nationally recognized statistical ratings organizations. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

We consider credit and nonperformance risk in our valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in our assessment of credit and nonperformance risk. We estimate a credit reserve for our outstanding derivative assets and liabilities at an individual transaction level in conjunction with the provisions of our master netting arrangements. Our assessment of credit and nonperformance risk did not affect our determination of the fair value of these derivative assets and liabilities. Likewise, no reserves were made in determining the fair value of our outstanding liabilities as a result of our own credit standing.

SFAS No. 157 establishes a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair

value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.
- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date where pricing inputs are other than quoted prices in active markets as Level 2. This category includes those derivative instruments that we value using models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 instruments primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. In most instances, the observable data is available for us to validate the inputs used to measure fair value; however, the cost of obtaining the information is prohibitive.

Derivative contracts can be exchange-traded or over-the counter (“OTC”) traded. We generally value exchange-traded derivatives within portfolios calibrated to market clearing levels on a daily basis. We value OTC derivatives using broker information based on executed market transactions that we have corroborated with other observable market data. For OTC derivatives that trade in liquid markets, such as generic forwards, swaps, and options, inputs can generally be verified and valuation does not involve significant management judgment.

Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult. Such instruments are classified within Level 3 of the fair value hierarchy. We include the fair value of financial assets and liabilities in Level 3 as a default due to limited market data or in most cases, due to lacking binding broker quotes to corroborate pricing data as required by current interpretations of SFAS No. 157 Level 2 requirements. Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or the interpretation of Level 2 criteria is modified in practice to include non-binding market corroborated data.

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 September 30, 2008. 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 the valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

Recurring fair value measures	Fair Value at September 30, 2008			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Derivative instruments, net	\$ —	\$ —	\$ 12.7	\$ 12.7
Liabilities:				
Derivative instruments, net	(157.6)	—	(95.5)	(253.1)
Total	<u>\$(157.6)</u>	<u>\$ —</u>	<u>\$(82.8)</u>	<u>\$(240.4)</u>

The table below provides a summary of changes in the fair value of our Level 3 financial assets and liabilities for the nine months ended September 30, 2008. As reflected in the table, the net unrealized gain on Level 3 financial assets and liabilities was \$4.6 million for the nine months ended September 30, 2008, which resulted from forward price decreases in natural gas, natural gas liquids, or NGLs, and crude oil derivative instruments that we held at September 30, 2008.

	Derivative Instruments, net (in millions)
Balance at January 1, 2008	\$(160.6)
Realized and unrealized net gains	79.3
Purchases and settlements	(1.5)
Transfer in (out) of Level 3	—
Balance at September 30, 2008	<u>\$ (82.8)</u>
Change in unrealized net gains relating to instruments still held at September 30, 2008	<u>\$ 4.6</u>

11. DERIVATIVE FINANCIAL INSTRUMENTS

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. We use derivative instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility of our cash flows. Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by a committee of senior management. 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. 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 instruments in our consolidated financial statements at fair value pursuant to the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, or SFAS No. 133, and the guidance set forth in SFAS No. 157 as discussed in Note 10 above. We adjust our consolidated financial statements each period for changes in the fair value of our derivative instruments, which we refer to as “marking to market” or “mark-to-market.” 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.

Under the guidance of SFAS No. 133, if a derivative instrument does not qualify as a hedge, or is not designated as a hedge, the derivative instrument is adjusted to its fair value each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in “Cost of natural gas” for our commodity-based derivatives. Our 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 instrument occurs.

If a derivative instrument qualifies and is designated as a cash flow hedge, 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 value is recognized each period in earnings. Realized gains and losses on derivative instruments that are designated as hedges and qualify for hedge accounting are included in “Cost of natural gas” 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 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 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. Additionally, both the counterparty credit standing and the ability to perform must be considered for both the hedge transaction and the physical transaction being hedged.

Non-Qualified Hedges

Many of our derivative 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 instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as “non-qualified.” Non-qualified derivative 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 when the associated derivative 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 generally different from the pricing index used for natural gas purchases, exposing us to basis price risk relative to changes in those two indices. By entering into a basis swap, we can effectively lock in the margin, or “spread,” representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, thereby removing locational price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative instruments (i.e., the basis swaps) 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 instruments are recorded in earnings.

2. **Storage**—In our Marketing segment, we use derivative instruments (i.e., natural gas swaps) to hedge the “margin,” representing 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 instruments is to lock in the margin between storage injections and withdrawals 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 retain 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 instrument is settled in a period that is different from when 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 New York Mercantile Exchange (“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. The changes in fair value of these derivative instruments from the date of de-designation are recorded in 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 instruments to hedge NGL volumes produced from our natural gas processing facilities. Many of our natural gas contracts provide us with the option of processing natural gas when it is economical, and allow us to cease processing when the “fractionation spread,” representing the relative difference between the price received for the NGLs produced less the cost of natural gas used for processing, becomes uneconomic. We have entered into derivative 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 when it is probable the processing will occur. Because our processing forecasts fluctuate due to market conditions, these derivative instruments are deemed “non-qualifying” hedges. For this reason, our operating income will be subject to increased volatility due to fluctuations in both natural gas and NGL prices until the underlying transactions are settled.

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 instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting treatment between the derivative instrument and the underlying transaction (i.e., the derivative instruments are recorded at fair 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 derivative instruments, which are recorded as an element of “Cost of natural gas” for our

commodity-based derivative instruments in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

<u>Derivative fair value gains (losses)</u>	<u>Three months ended September 30,</u>		<u>Nine months ended September 30,</u>	
	<u>2008</u>	<u>2007</u>	<u>2008</u>	<u>2007</u>
	<u>(in millions)</u>			
Natural Gas segment				
Hedge ineffectiveness	\$ 0.1	\$(0.5)	\$ (1.1)	\$ (0.2)
Non-qualified hedges	36.5	(7.2)	42.5	(13.2)
Marketing segment				
Non-qualified hedges	<u>11.0</u>	<u>2.9</u>	<u>(23.9)</u>	<u>(4.0)</u>
Derivative fair value gains (losses)	<u>\$47.6</u>	<u>\$(4.8)</u>	<u>\$ 17.5</u>	<u>\$(17.4)</u>

De-designation and Settlement of Derivatives

We record the change in fair value of our cash flow hedges in AOCI until the derivative instruments are settled, at which time they are reclassified from AOCI to earnings. Also included in AOCI at September 30, 2008 are unrecognized losses of approximately \$1.6 million associated with cash flow hedges that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three and nine months ended September 30, 2008, we reclassified losses of \$52.1 million and \$112.4 million, respectively, from AOCI to “Cost of natural gas” on our consolidated statements of income for the fair value of derivative instruments that were settled.

In connection with our April 2008 issuance and sale of \$800 million in principal amount of Notes, we paid \$22.1 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the Notes maturing in 2038. The \$22.1 million is being amortized from AOCI to “Interest expense” over the 30-year term of the Notes.

Derivative Positions

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

	<u>September 30, 2008</u>	<u>December 31, 2007</u>
	<u>(in millions)</u>	
Other current assets	\$ 2.6	\$ 6.5
Other assets, net	9.6	6.4
Accounts payable and other	(118.3)	(165.5)
Other long-term liabilities	<u>(134.3)</u>	<u>(192.9)</u>
	<u>\$ (240.4)</u>	<u>\$ (345.5)</u>

The decrease in our obligation associated with derivative activities is primarily due to a decline in forward and daily natural gas, NGL and condensate prices from December 31, 2007 to September 30, 2008. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We present the fair value of our derivative contracts on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. Our credit exposure for OTC derivatives is directly with our counterparty

and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

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

	September 30, 2008	December 31, 2007
	(in millions)	
Counterparty Credit Quality*		
AAA	\$ —	\$ —
AA	(164.0)	(298.3)
A	(76.4)	(47.2)
Lower than A	—	—
Total	<u><u>\$(240.4)</u></u>	<u><u>\$(345.5)</u></u>

* As determined by nationally recognized statistical ratings organizations.

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:

	For the three months ended September 30, 2008				
	Liquids	Natural Gas	Marketing	Corporate ⁽¹⁾	Total
	(in millions)				
Total revenue	\$209.3	\$2,233.4	\$1,352.8	\$ —	\$3,795.5
Less: Intersegment revenue	0.1	928.5	54.2	—	982.8
Operating revenue	209.2	1,304.9	1,298.6	—	2,812.7
Cost of natural gas	—	1,122.4	1,285.1	—	2,407.5
Operating and administrative	52.0	83.8	2.5	1.6	139.9
Power	35.0	—	—	—	35.0
Depreciation and amortization	26.7	31.5	0.4	—	58.6
Operating income	95.5	67.2	10.6	(1.6)	171.7
Interest expense	—	—	—	50.7	50.7
Other income	—	—	—	0.3	0.3
Income before income tax expense	95.5	67.2	10.6	(52.0)	121.3
Income tax expense	—	—	—	1.9	1.9
Net income	<u><u>\$ 95.5</u></u>	<u><u>\$ 67.2</u></u>	<u><u>\$ 10.6</u></u>	<u><u>\$(53.9)</u></u>	<u><u>\$ 119.4</u></u>
Capital expenditures (excluding acquisitions) . .	<u><u>\$261.1</u></u>	<u><u>\$ 62.7</u></u>	<u><u>\$ —</u></u>	<u><u>\$ 4.3</u></u>	<u><u>\$ 328.1</u></u>

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

For the three months ended September 30, 2007

	<u>Liquids</u>	<u>Natural Gas</u>	<u>Marketing</u> (in millions)	<u>Corporate⁽¹⁾</u>	<u>Total</u>
Total revenue	\$138.1	\$1,376.0	\$790.3	\$ —	\$2,304.4
Less: Intersegment revenue	—	528.7	64.8	—	593.5
Operating revenue	138.1	847.3	725.5	—	1,710.9
Cost of natural gas	—	711.2	719.6	—	1,430.8
Operating and administrative	33.9	68.1	2.3	(0.5)	103.8
Power	29.7	—	—	—	29.7
Depreciation and amortization	16.9	27.7	0.4	—	45.0
Operating income	57.6	40.3	3.2	0.5	101.6
Interest expense	—	—	—	23.4	23.4
Other income	—	—	—	0.4	0.4
Income before income tax expense	57.6	40.3	3.2	(22.5)	78.6
Income tax expense	—	—	—	1.3	1.3
Net income	<u>\$ 57.6</u>	<u>\$ 40.3</u>	<u>\$ 3.2</u>	<u>\$(23.8)</u>	<u>\$ 77.3</u>
Capital expenditures (excluding acquisitions) . .	<u>\$354.4</u>	<u>\$ 186.8</u>	<u>\$ 0.1</u>	<u>\$ (4.4)</u>	<u>\$ 536.9</u>

⁽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 nine months ended September 30, 2008					
	Liquids	Natural Gas	Marketing (in millions)	Corporate ⁽¹⁾	Total
Total revenue	\$ 555.5	\$6,388.2	\$4,025.8	\$ —	\$10,969.5
Less: Intersegment revenue	0.3	2,582.9	206.1	—	2,789.3
Operating revenue	555.2	3,805.3	3,819.7	—	8,180.2
Cost of natural gas	—	3,302.8	3,817.8	—	7,120.6
Operating and administrative	130.8	235.8	7.1	4.7	378.4
Power	104.6	—	—	—	104.6
Depreciation and amortization	73.0	88.8	1.3	—	163.1
Operating income	246.8	177.9	(6.5)	(4.7)	413.5
Interest expense	—	—	—	129.7	129.7
Other income	—	—	—	2.5	2.5
Income before income tax expense	246.8	177.9	(6.5)	(131.9)	286.3
Income tax expense	—	—	—	5.0	5.0
Net income	\$ 246.8	\$ 177.9	\$ (6.5)	\$ (136.9)	\$ 281.3
Total assets	\$3,709.9	\$3,692.5	\$ 353.1	\$ 225.6	\$ 7,981.1
Capital expenditures (excluding acquisitions)	\$ 762.8	\$ 226.6	\$ —	\$ 10.8	\$ 1,000.2

⁽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 nine months ended September 30, 2007					
	Liquids	Natural Gas	Marketing (in millions)	Corporate ⁽¹⁾	Total
Total revenue	\$ 400.3	\$4,084.7	\$2,634.0	\$ —	\$7,119.0
Less: Intersegment revenue	—	1,767.6	189.1	—	1,956.7
Operating revenue	400.3	2,317.1	2,444.9	—	5,162.3
Cost of natural gas	—	1,966.2	2,424.5	—	4,390.7
Operating and administrative	108.2	190.3	5.8	2.3	306.6
Power	87.1	—	—	—	87.1
Depreciation and amortization	50.0	70.1	1.2	—	121.3
Operating income	155.0	90.5	13.4	(2.3)	256.6
Interest expense	—	—	—	70.2	70.2
Other income	—	—	—	2.3	2.3
Income before income tax expense	155.0	90.5	13.4	(70.2)	188.7
Income tax expense	—	—	—	3.7	3.7
Net income	\$ 155.0	\$ 90.5	\$ 13.4	\$ (73.9)	\$ 185.0
Total assets	\$2,624.1	\$3,261.0	\$ 261.6	\$207.1	\$6,353.8
Capital expenditures (excluding acquisitions)	\$ 847.8	\$ 572.7	\$ 1.6	\$ 6.3	\$1,428.4

⁽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. SUBSEQUENT EVENT

Distribution to Partners

On October 13, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2008. The distribution will be paid to unitholders of record as of November 6, 2008, of our available cash of \$108.8 million at September 30, 2008, or \$0.990 per common unit. Of this distribution, \$74.9 million will be paid in cash, \$14.3 million will be distributed in i-units to our i-unitholder, \$18.9 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.

14. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner; any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the effect this pronouncement will have on our present computation of earnings per unit.

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, 2007.

DISRUPTION TO FUNCTIONING OF CAPITAL MARKETS

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to raise debt and equity at prices that are similar to offerings in recent years to be limited over the next three to six months and possibly longer should capital markets remain constrained.

In the weeks following the third quarter, our unit price declined to a closing low of \$27.07 on October 10, 2008. Since that date our unit price recovered partially to a level of \$37.89 on October 30, 2008. 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 reduced to moderate 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.

RESULTS OF OPERATIONS—OVERVIEW

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

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

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

The following table reflects our operating income by business segment and corporate charges for the three and nine month periods ended September 30, 2008 and 2007:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Income				
Liquids	\$ 95.5	\$ 57.6	\$246.8	\$155.0
Natural Gas	67.2	40.3	177.9	90.5
Marketing	10.6	3.2	(6.5)	13.4
Corporate, operating and administrative	(1.6)	0.5	(4.7)	(2.3)
Total Operating Income	171.7	101.6	413.5	256.6
Interest expense	50.7	23.4	129.7	70.2
Other income	0.3	0.4	2.5	2.3
Income tax expense	1.9	1.3	5.0	3.7
Net Income	<u>\$119.4</u>	<u>\$ 77.3</u>	<u>\$281.3</u>	<u>\$185.0</u>

Several types of 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. We employ derivative financial instruments to reduce our exposure to natural gas and NGL price volatility. 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. 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 commodity prices.

Summary Analysis of Operating Results

Liquids

Operating income from our Liquids segment increased by \$37.9 million to \$95.5 million for the three months ended September 30, 2008, from the \$57.6 million for the same period of 2007. Operating income for the nine months ended September 30, 2008 increased by \$91.8 million to \$246.8 million from \$155.0 million for the same period of 2007. The increase in operating income of our Liquids segment is primarily due to the following:

- Tariff increases that went into effect in January, April, and July 2008, which include increases associated with the first stage of our Southern Access Expansion and the Phase V expansion of our North Dakota system;
- Additional revenue resulting from higher average crude oil prices associated with the allowance oil we receive in connection with our transportation services; and
- Higher delivery volumes on our Lakehead system.

Natural Gas

Operating income from our Natural Gas segment increased by \$26.9 million to \$67.2 million for the three months ended September 30, 2008 from the \$40.3 million for the same period of 2007. Operating income for the nine months ended September 30, 2008 increased by \$87.4 million to \$177.9 million, from

\$90.5 million for the comparable period in 2007. The following factors affected the operating income of our Natural Gas business:

- \$36.6 million of unrealized, non-cash mark-to-market gains from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of \$7.7 million for the same period of 2007;
- Improved margins resulting from higher prices we received for the natural gas, NGLs and condensate we receive as payment for the services we provide;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;
- Reduced revenues of approximately \$8 to \$9 million associated with the impact of hurricanes Gustav and Ike. Natural gas revenues decreased when third-party facilities downstream of our operations were damaged or without power. Physical damage was minimal, although we expect to incur capital and operating costs approximating \$2 million to \$3 million for repairs to several of our natural gas systems during the fourth quarter of 2008. All of our major natural gas systems were returned to pre-hurricane levels by the end of September;
- Lower processing margins resulting from higher average prices for natural gas used for processing, coupled with a continued shift in our contract mix from keep-whole to percentage of liquids, or POL, type contracts;
- Declines in the prices of natural gas and NGLs from June 30, 2008 to September 30, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to fair market value; and
- Variable operating and administrative cost increases associated with our system growth.

For the nine months ended September 30, 2008, in addition to the factors discussed above, we had \$41.4 million of unrealized, non-cash mark-to-market gains, representing a \$54.8 million improvement from the \$13.4 million of losses we experienced in the same period of 2007. Additionally, operating income for the nine months ended September 30, 2008 was not affected by unscheduled maintenance at our Zybach processing facility and measurement losses which negatively affected operating income during the same period of 2007.

Marketing

Operating income from our Marketing segment increased by \$7.4 million to \$10.6 million for the three months ended September 30, 2008 compared to \$3.2 million in the same period in 2007. For the nine months ended September 30, 2008, operating income decreased by \$19.9 million to an operating loss of \$6.5 million from operating income of \$13.4 million in the same period of 2007. The operating results of our Marketing segment for the three months ended September 30, 2008 were positively affected by \$11.0 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 as compared with \$2.9 million for the same period in 2007. Offsetting the unrealized non-cash, mark-to-market gains were \$6.1 million and \$3.0 million of non-cash charges for the three months ended September 30, 2008 and 2007, respectively, we recorded to reduce the cost basis of our natural gas inventory to fair market value. Both the non-cash, mark-to-market gains and revaluation charges resulted from declines in the price of natural gas during the three months ended September 30, 2008.

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 Statement of Financial Accounting Standards 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.

The fair values of all our derivative instruments reflect our best estimate of the price we would receive for selling an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. SFAS No. 157 defines how we are to determine fair value, establishes criteria for measuring fair value, and requires additional disclosures for assets and liabilities that we report at fair value. We adopted the provisions of SFAS No. 157 prospectively beginning January 1, 2008, which did not affect our results of operations, financial condition or cash flows due to the nature of our derivative instruments and our existing valuation methods.

Our unrealized, non-cash mark-to-market gains of \$47.6 million and \$17.5 million for the three and nine months ended September 30, 2008, are primarily the result of lower forward and daily prices of natural gas and NGLs relative to June 30, 2008 and December 31, 2007, respectively. The changes in fair value of our portfolio of commodity-based derivative instruments that do not qualify for hedge accounting are a result of the continuing volatility in the underlying prices for natural gas, NGLs and crude oil. During the three and nine months ended September 30, 2007, rising natural gas and NGL prices relative to the prices at June 30, 2007 and December 31, 2006, produced unrealized mark-to-market losses for the respective periods. Mark-to-market gains or losses create volatility in our operating results although the derivative instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains and losses to reverse in future periods as we settle the derivative instruments against the underlying physical transactions. We intend to continue using derivative instruments to hedge our portfolio of natural gas and NGLs because of the economic benefit we derive from minimizing 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.

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:

<u>Derivative fair value gains (losses)</u>	<u>Three months ended September 30,</u>		<u>Nine months ended September 30,</u>	
	<u>2008</u>	<u>2007</u>	<u>2008</u>	<u>2007</u>
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	\$ 0.1	\$(0.5)	\$ (1.1)	\$ (0.2)
Non-qualified hedges	36.5	(7.2)	42.5	(13.2)
Marketing segment				
Non-qualified hedges	<u>11.0</u>	<u>2.9</u>	<u>(23.9)</u>	<u>(4.0)</u>
Derivative fair value gains (losses)	<u>\$47.6</u>	<u>\$(4.8)</u>	<u>\$ 17.5</u>	<u>\$(17.4)</u>

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

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

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Results				
Operating revenues	\$209.2	\$138.1	\$555.2	\$400.3
Operating and administrative	52.0	33.9	130.8	108.2
Power	35.0	29.7	104.6	87.1
Depreciation and amortization	26.7	16.9	73.0	50.0
Operating expenses	113.7	80.5	308.4	245.3
Operating Income	<u>\$ 95.5</u>	<u>\$ 57.6</u>	<u>\$246.8</u>	<u>\$155.0</u>
Operating Statistics				
Lakehead system:				
United States ⁽¹⁾	1,233	1,187	1,242	1,191
Province of Ontario ⁽¹⁾	331	325	344	333
Total Lakehead system deliveries⁽¹⁾	<u>1,564</u>	<u>1,512</u>	<u>1,586</u>	<u>1,524</u>
Barrel miles (billions)	<u>105</u>	<u>101</u>	<u>317</u>	<u>301</u>
Average haul (miles)	<u>730</u>	<u>723</u>	<u>729</u>	<u>723</u>
Mid-Continent system deliveries⁽¹⁾	<u>227</u>	<u>255</u>	<u>238</u>	<u>248</u>
North Dakota system:				
Trunkline	101	93	103	91
Gathering	6	7	6	6
Total North Dakota system deliveries⁽¹⁾	<u>107</u>	<u>100</u>	<u>109</u>	<u>97</u>
Total Liquids Segment Delivery Volumes⁽¹⁾	<u>1,898</u>	<u>1,867</u>	<u>1,933</u>	<u>1,869</u>

⁽¹⁾ Average barrels per day (“Bpd”) in thousands.

Three months ended September 30, 2008 compared with three months ended September 30, 2007

Our Liquids segment accounted for \$95.5 million of operating income during the three months ended September 30, 2008, an increase of \$37.9 million from the \$57.6 million generated during the same period in 2007. The favorable results are attributable to increased volumes transported on our Liquids systems coupled with tariff increases that went into effect during 2008, partially offset by higher power, operating and administrative costs, and depreciation. The majority of the increase in delivery volumes is attributable to our Lakehead system; however, our North Dakota system also realized increased delivery volumes.

Operating revenue for the three months ended September 30, 2008 increased by \$71.1 million to \$209.2 million from \$138.1 million for the same period in 2007. The increase in operating revenue is due to the following:

- Increased average tariffs on all of our major systems;

- The toll charges discussed below that are associated with the first stage of our Southern Access expansion project became effective April 1, 2008. We realize revenues in connection with this increased surcharge as crude oil is delivered from our Lakehead system. Our Southern Access expansion project includes a 42-inch diameter pipeline from Superior to Delavan, Wisconsin along with pump station enhancements upstream and downstream of this segment. Completion of the first stage of this project added approximately 190,000 Bpd of capacity and was considered available for service April 1, 2008;
- Higher delivery volumes on our Lakehead system; and
- Additional revenue resulting from higher crude oil prices associated with the allowance oil we receive in connection with our transportation services.

The increases in average tariffs on all three Liquids systems coupled with longer hauls and transportation of more heavy crude oil contributed approximately \$57.0 million of additional operating revenue. We implemented new tariffs in 2008 on our Lakehead system effective April 1, 2008 to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2008. The projected costs for 2008 include 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. We also implemented new tariffs on our North Dakota system effective January 1, 2008 that are applicable for five years and are applied to all transportation routes with a destination of Clearbrook, Minnesota. Additionally, we increased the average tariffs on all three of our Liquids systems in connection with the annual index rate ceiling adjustment that went into effect July 1, 2008. Additional discussion of these tariffs is provided below under the section labeled *Regulatory Matters—FERC Transportation Tariffs—Liquids*.

Average delivery volumes on our Lakehead system increased approximately 3.4 percent, to 1.564 million Bpd during the three months ended September 30, 2008 from 1.512 million Bpd during the same period in 2007, contributing an additional \$3.6 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands. However, crude oil supplies from western Canada were lower than we expected due to two primary factors. First, Suncor, an oil sands producer in Alberta, Canada, had limited hydrotreating capacity in August and September of 2008 as well as an accident on their oil sands pipeline both of which reduced production volumes. Second, Syncrude, another oil sands producer, is currently undergoing a maintenance turnaround that has resulted in lower production volumes.

Included in our transportation tariff is 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 September 30, 2008 are substantially higher than the average prices for the same period of 2007. For example, the average price of West Texas Intermediate crude oil has increased approximately 60 percent for the three months ended September 30, 2008 as compared with the same period in 2007. As a result of the increase in crude oil prices, we experienced an approximate \$8.2 million increase in allowance oil revenues.

Operating and administrative expenses for the Liquids segment increased \$18.1 million for the three months ended September 30, 2008, compared with the same period in 2007. 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;
- Higher costs incurred in connection with our pipeline integrity management program;

- Further costs incurred in connection with the crude oil release and fire on Line 3 of our Lakehead system; and
- Favorable settlements of property tax assessments that were realized during the three months ended September 30, 2007 which were not present for the same period in 2008.

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 gains and losses, which result 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, of the level of our carriers inventory and the inventory positions of customers.

Power costs increased \$5.3 million in the three months ended September 30, 2008, compared with the same period in 2007, predominantly due to the higher delivery volumes coupled with higher utility rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and coal costs.

The increase in depreciation expense of \$9.8 million is attributable to the additional assets we have placed in service during the last quarter of 2007 and the first three quarters of 2008, including the Southern Access Expansion stage one assets that we placed in service during the second quarter of 2008 along with the assets placed into service on our North Dakota and Mid-Continent systems.

Nine months ended September 30, 2008 compared with nine months ended September 30, 2007

Our Liquids segment accounted for \$246.8 million of operating income during the nine months ended September 30, 2008, representing a \$91.8 million increase over the \$155.0 million for the same period in 2007. The components comprising our operating income changed during the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007, primarily for the same reasons as noted above in our three-month analysis except that we had more favorable experience with oil measurement adjustments for the nine months ended September 30, 2008.

Future Prospects Update for Liquids

We and Enbridge Inc. (“Enbridge”) are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States (“U.S.”). 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 year ended December 31, 2007.

Partnership Projects

Southern Access

We continue to progress on the second and final stage of the expansion project which will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois. Construction of this stage of the project commenced on June 1, 2008. We expect to complete this phase of the expansion by the end of the first quarter of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

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, 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 United States 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 in mid-2010. We expect to begin construction on the U.S. leg of the project in the first quarter of 2009.

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 United States portion of the Williston Basin and has determined there to be 3.0 to 4.3 billion barrels of technologically recoverable oil. 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 tariff 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 Regulation Commission ("FERC") in October 2008.

Superior and Griffith Storage

Due to forecasted production increases of synthetic heavy crude oil that we anticipate will be transported on the Enbridge/Lakehead mainline systems from Western Canada to Chicago, Illinois; we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We are building two tanks with operational capacity of approximately 205,000 barrels each. The Superior tank was completed in early September 2008 and the Griffith tank is on schedule to be completed in December 2008.

Trailbreaker (formerly Eastern PADD II Access)

We and Enbridge are jointly developing plans to provide access for western Canadian crude oil to refineries along the United States Eastern Seaboard and the United States Gulf Coast ("U.S. Gulf Coast") via the marine terminal at Portland, Maine. The Trailbreaker project involves the expansion and reversal of existing facilities to create a pipeline route to Portland that is ready for use in 2010. Commercial terms for the project are being negotiated which will be subject to regulatory approvals in both the United States and Canada. Preliminary estimates indicate our portion of the project will approximate \$0.3 billion (excluding capitalized interest).

Enbridge and Other Projects

Spearhead Pipeline

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that previously shipped crude oil from Cushing, Oklahoma to Chicago. Enbridge reversed the pipeline, renamed it Spearhead, and began delivering Canadian crude oil to the major oil hub at Cushing in March 2006. Since then, the pipeline has operated at or near its capacity of 125,000 Bpd. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 190,000 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 has commenced on the 65,000 Bpd expansion, which is expected to be in service in early 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. Enbridge filed a petition for declaratory order with the FERC in October 2007, which was denied on May 7, 2008. Enbridge is currently working with shippers to develop a new commercial structure for the pipeline.

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. 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 to be 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. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line.

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. The GIC approval has been challenged through proceedings in the Federal Court of Canada by certain First Nations on the basis that the Canadian government failed to adequately consult with affected First Nations. No hearing date has been set and the likelihood of success of this action is not determinable at this time. Enbridge has filed the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. 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. In conjunction with our Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right-of-way in Illinois. Construction and right-of-way acquisition related to this project continues in tandem with the Southern Access project. 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 later this year. The target in-service date for this pipeline system is late 2012.

Texas Access Pipeline

The initiative discussed above aligns with the Enbridge strategy to pursue a staged approach to the U.S. Gulf Coast that matches supply growth. The Texas Access pipeline will be brought to the forefront when a large volume solution to the U.S. Gulf Coast is required.

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:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Results				
Operating revenues	\$ 1,304.9	\$ 847.3	\$ 3,805.3	\$ 2,317.1
Cost of natural gas	1,122.4	711.2	3,302.8	1,966.2
Operating and administrative	83.8	68.1	235.8	190.3
Depreciation and amortization	31.5	27.7	88.8	70.1
Operating expenses	1,237.7	807.0	3,627.4	2,226.6
Operating Income	<u>\$ 67.2</u>	<u>\$ 40.3</u>	<u>\$ 177.9</u>	<u>\$ 90.5</u>
Operating Statistics (MMBtu/d)				
East Texas	1,443,000	1,158,000	1,431,000	1,162,000
Anadarko	682,000	594,000	648,000	588,000
North Texas	388,000	360,000	383,000	344,000
UTOS	96,000	212,000	157,000	176,000
MidLa	96,000	110,000	104,000	117,000
AlaTenn	28,000	30,000	41,000	41,000
Bamagas	99,000	148,000	79,000	126,000
Other major intrastates	204,000	205,000	215,000	241,000
Total ⁽¹⁾	<u>3,036,000</u>	<u>2,817,000</u>	<u>3,058,000</u>	<u>2,795,000</u>

⁽¹⁾ We have excluded from the table above average daily volumes of 10,000 MMBtu/d and 24,000 MMBtu/d for the three and nine month periods ended September 30, 2007, respectively, associated with the KPC system which we sold in November 2007.

Three months ended September 30, 2008 compared with three months ended September 30, 2007

Our Natural Gas segment contributed \$67.2 million of operating income for the three months ended September 30, 2008, an increase of \$26.9 million from the \$40.3 million contributed in the corresponding period of 2007. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the three months ended September 30, 2008 as compared with the same period of 2007:

- \$36.6 million of unrealized, non-cash mark-to-market gains from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of \$7.7 million for the same period of 2007;
- Reduced revenues of approximately \$8 to \$9 million associated with the impact of hurricanes Gustav and Ike. Natural gas revenues decreased when third-party facilities downstream of our operations were damaged or without power. Physical damage was minimal, although we expect to incur capital and operating costs approximating \$2 million to \$3 million for repairs to several of our natural gas systems during the fourth quarter of 2008. All of our major natural gas systems were returned to pre-hurricane levels by the end of September;
- In-kind payments we receive for the services we provide in the form of natural gas, NGLs and condensate have generated improved margins as a result of higher average prices in the commodities market;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;
- Declining processing margins due to higher costs of natural gas used for processing as the average price for natural gas declined less than the price for NGLs, along with continued changes in our contract mix of keep whole and POL type contracts;
- Declines in the prices of natural gas and NGLs from June 30, 2008 to September 30, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to fair market value; and
- Increased workforce, repair and maintenance, rents, leases, and depreciation associated with our system growth.

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We are exposed to fluctuations in commodity prices in the near term on 20 to 30 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 increase when the prices of these commodities are rising and decrease when the prices are declining. For the three months ended September 30, 2008, we realized approximately \$22 million of additional margin compared with the same period of 2007 primarily due to the higher prices we received from the sale of the unhedged natural gas, NGLs and condensate that we received in-kind as compensation for our services.

We enter into derivative financial instruments to hedge 70 to 80 percent of our near-term exposure to commodity prices associated with the in-kind compensation we receive for our services. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the processed natural gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate during that time. Many of these derivative financial instruments do not qualify for hedge accounting which results in the derivative instrument being marked-to-market in our operating results. This accounting treatment produces unrealized non-cash gains

and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

The operating income of our Natural Gas segment for the three months ended September 30, 2008 was positively affected by unrealized non-cash, mark-to-market net gains of \$36.6 million, representing an increase of \$44.3 million from the \$7.7 million of losses we recorded for the same period of 2007. During the three months ended September 30, 2008, declines in the forward and daily market prices of natural produced non-cash, mark-to-market gains in our portfolio of derivative instruments. The declining price environment that was prevalent during the three months ended September 30, 2008, was not present during the same period of 2007. We expect the net mark-to-market gains to be offset when the related physical transactions are settled. The following table depicts the affect that unrealized non-cash mark-to-market gains and losses had on the operating results of our Natural Gas business for the three and nine months ended September 30, 2008 and 2007:

<u>Derivative fair value gains (losses)</u>	<u>Three months ended September 30,</u>		<u>Nine months ended September 30,</u>	
	<u>2008</u>	<u>2007</u>	<u>2008</u>	<u>2007</u>
	<u>(in millions)</u>			
Natural Gas segment				
Hedge ineffectiveness	\$ 0.1	\$(0.5)	\$(1.1)	\$ (0.2)
Non-qualified hedges	<u>36.5</u>	<u>(7.2)</u>	<u>42.5</u>	<u>(13.2)</u>
Derivative fair value gains (losses)	<u>\$36.6</u>	<u>\$(7.7)</u>	<u>\$41.4</u>	<u>\$(13.4)</u>

The increase in the 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. We completed the following projects during 2008 and the last quarter of 2007, which have contributed to the increase in average daily volumes and operating results of our major natural gas systems:

- In May 2008 our expansion of the Aker treating plant on our East Texas system was completed and placed into service adding 125 million cubic feet per day, or MMcf/d, of treating capacity.
- The \$635 million expansion and extension of our East Texas natural gas system, referred to as the Clarity project, is substantially complete and includes:
 - A new 36-inch natural gas pipeline from Bethel, Texas to Southeast Texas near Beaumont, Texas; and
 - The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed in service in March 2007.

We expect to finish an additional pipeline connection and two compression stations during the first quarter of 2009. The total added capacity related to this project will then total approximately 700 MMcf/d.

- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas.
- In the latter half of 2007, we completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.
- Construction and expansion of the Weatherford processing facility within our North Texas system was completed late in 2007 and added approximately 75 MMcf/d of processing capacity.

With the expansions we completed in 2007 and 2008 we are now able to provide additional gathering, processing, treating and transportation services for our customers which has contributed to our volume growth in the third quarter of 2008. Volume and revenue growth is also the result of additional wellhead supply contracts and continued robust drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale and Granite Wash areas. We expect the volumes on our major natural gas systems to continue increasing throughout the year as a result of our investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas we serve.

During the third quarter of 2008, we experienced operational disruptions to our onshore and offshore natural gas facilities as a result of hurricanes Gustav and Ike. Our facilities in Texas and Louisiana sustained minimal physical damage from the hurricanes, although some of our natural gas systems had lower throughput and revenues in the month of September due to the inability of third-party downstream facilities to receive deliveries of our natural gas and NGLs. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants and transport natural gas to markets in the Texas and Louisiana regions. Our current estimate of lost revenue associated with the hurricanes is \$8 million to \$9 million coupled with capital and operating costs of \$2 million to \$3 million we expect to incur in the fourth quarter for repairs to our damaged facilities. We do not anticipate recovery of any significant amounts of insurance for these losses. The majority of our facilities returned to normal operation by the end of September.

The processing margins we derive from processing natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems declined 52 percent during the third quarter of 2008 in relation to the same period of 2007. Operating income derived from keep-whole processing arrangements for the three months ended September 30, 2008 was \$18.4 million, representing a decrease of \$19.6 million from the \$38.0 million we produced for the same period in 2007. During the third quarter of 2008, NGL and crude oil prices began to decline faster than natural gas prices, which have the effect of reducing revenue we derive from our processing assets less the cost of natural gas purchased for processing. In addition to the affect that changing prices have had on the processing margins we derive from processing natural gas under keep-whole arrangements, we continue to experience 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 may reduce our exposure to commodity price risk along with a portion of the operating income we derive from processing natural gas under keep-whole arrangements.

Despite the higher average daily prices for natural gas and NGLs we received during the three months ended September 30, 2008 relative to the same period of 2007, the daily prices for natural gas and NGLs at September 30, 2008 were lower than the prices for these commodities at June 30, 2008. The lower commodity prices at September 30, 2008 produced approximately \$4.8 million of revaluation losses with respect to our in-kind natural gas imbalances, as well as approximately \$2.2 million of non-cash charges to reduce the cost basis of our natural gas inventory to fair market value. We did not experience similar fluctuations in commodity prices for the three months ended September 30, 2007.

Operating and administrative costs of our Natural Gas segment were \$15.7 million greater for the three months ended September 30, 2008 than the three months ended September 30, 2007, primarily as a result of increased workforce-related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of pipeline expansions across the areas we serve.

Materials, supplies and other costs along with repair and maintenance costs were higher predominantly due to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our natural gas systems. We expect workforce related costs in addition to materials, supplies and other costs to increase in relation to the increase in volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was higher in the third quarter of 2008 as compared the third quarter of 2007, as a result of the capital projects completed and placed in-service during the first nine months of 2008 and the last quarter of 2007. We expect depreciation expense will be higher in 2008 as a result of the projects we completed and placed in service throughout 2007 and the first half of 2008.

Nine months ended September 30, 2008 compared with nine months ended September 30, 2007

Our Natural Gas segment accounted for \$177.9 million of operating income during the nine months ended September 30, 2008, representing an \$87.4 million increase over the \$90.5 million for the same period in 2007. The components comprising our operating income changed favorably during the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007, primarily for the same reasons noted above in our three-month analysis except for those items described below.

The operating income of our Natural Gas business derived from processing increased by approximately \$30 million during the nine months ended September 30, 2008, as compared with the same period in 2007, despite the impact of the hurricanes and the declining price environment that occurred late in the third quarter of 2008 as discussed above under our three month analysis. For a majority of the nine months ended September 30, 2008, we have benefitted from a favorable pricing environment for the production of NGLs. NGL prices were high relative to natural gas prices during most of the nine month period of 2008 providing a favorable environment for the production of NGLs from our processing assets. We have also benefitted from the processing capacity we added on our Anadarko system in April 2007 of approximately 120 MMcf/d and the 75 MMcf/d we added on our North Texas system in the second half of 2007. The added processing capacity provided us with the ability to generate additional processing margin from the NGLs we produced during the first nine months of 2008. Our Zymbach processing plant has also continued to operate at expected levels during the first nine months of 2008, which compares favorably with the same period of 2007 when we experienced operational issues that reduced processing margins by approximately \$11 million.

Operating income for the nine months ended September 30, 2008 was positively affected by the unrealized non-cash, mark-to-market net gains of \$41.4 million from our derivative activities, which is approximately \$54.8 million more than the \$13.4 million of losses we recorded for the same period of 2007. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled.

Future Prospects Update for Natural Gas

Significant liquidity tightening and volatility in the capital markets will necessitate a less aggressive capital program in our natural gas business in the near term. During this period of volatility we will continue to focus our efforts primarily on development of our existing pipeline systems. We continue to evaluate strategic opportunities to further expand the service capabilities of our existing system and we may pursue opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During the third quarter of 2008, increased production from active drilling in the areas where our gathering systems are located has contributed to our volume growth. Recent announcements by natural gas producers forecasting reduced exploration and development

programs could impact the rate of growth in our natural gas assets. However, we believe our assets are located in three areas where producers are likely to remain active due to the higher probability of success associated with resource developments in the East Texas, North Texas and Anadarko regions. We believe this factor should temper the impact of lower natural gas production drilling programs on the results of our Natural Gas business.

Milsap Plant

We plan to purchase and construct a 55 MMcf/d cryogenic processing plant and associated piping, which we refer to as the Millsap Plant Project, to accommodate Barnett Shale growth opportunities in North Texas. The design will incorporate flexibility to expand the inlet capacity of the plant to 75 MMcf/d (through expansion of inlet and residue compression) should volume growth exceed our expected forecast. We expect the cost to complete construction to approximate \$100 million with an in service date late in the first quarter of 2010.

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 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. We expect to complete this project during 2009 at an approximate cost of \$60 million.

Marketing

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

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Results				
Operating revenues	\$1,298.6	\$725.5	\$3,819.7	\$2,444.9
Cost of natural gas	1,285.1	719.6	3,817.8	2,424.5
Operating and administrative	2.5	2.3	7.1	5.8
Depreciation and amortization	0.4	0.4	1.3	1.2
Operating expenses	1,288.0	722.3	3,826.2	2,431.5
Operating Income (Loss)	\$ 10.6	\$ 3.2	\$ (6.5)	\$ 13.4

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.

We adopted the provisions of SFAS No. 157 effective January 1, 2008, which did not affect the operating results of our Marketing business, but did expand the disclosures we provide about how we determine the fair value of our derivative instruments. Refer to the discussions included in Notes 9 and 10 of our consolidated financial statements included in Item 1 of this report and also to the discussions below under “Derivative Activities” and the “Quantitative and Qualitative Disclosures about Market Risk” we include in Item 3 of this report for more information about our derivative activities.

Three months ended September 30, 2008 compared with three months ended September 30, 2007

The operating income of our Marketing segment increased to \$10.6 million for the third quarter of 2008 from \$3.2 million for the corresponding period in 2007. Included in operating income for the third quarter of 2008 are approximately \$11.0 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with the \$2.9 million of unrealized mark-to-market gains for the same period of 2007. During the three months ended September 30, 2008, declines in the forward and daily market prices of natural gas produced non-cash, mark-to-market gains in our portfolio of derivative instruments in excess of those produced during the same period of 2007. We expect these net mark-to-market gains to be offset when the related physical transactions are settled.

Operating income for the three months ended September 30, 2008 was also negatively affected by non-cash charges of \$6.1 million we recorded to reduce the cost basis of our natural gas inventory to fair market value at September 30, 2008, which is \$3.1 million more than the \$3.0 million non-cash charge we recorded for the same period of 2007. The average daily price of natural gas as published by Platt's Gas Daily for Henry Hub was approximately \$7.23 per MMBtu for the month of September 2008, a decline from \$12.60 per MMBtu for the month of June 2008. As a result of this decline in the price of natural gas inventory at our storage locations from June 30, 2008 to September 30, 2008, the weighted average cost of our natural gas inventory at September 30, 2008 exceeded the market price of natural gas by approximately \$6.1 million. 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.

The operating and administrative expenses of our Marketing business were slightly more in the quarter ended September 30, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Nine months ended September 30, 2008 compared with nine months ended September 30, 2007

Operating income of our Marketing segment declined to a loss of \$6.5 million for the nine month period ended September 30, 2008 from income of \$13.4 million for the corresponding period in 2007. Included in the operating loss for the first nine months of 2008 are approximately \$23.9 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, compared to the \$4.0 million of unrealized mark-to-market losses for the comparable period of 2007. The unrealized, mark-to-market losses for the nine months ended September 30, 2008 result from increases in the forward and daily market prices of natural gas from December 31, 2007. We expect these net mark-to-market losses to be offset when the related physical transactions are settled.

The operating and administrative expenses of our Marketing business are slightly more in the nine months ended September 30, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Corporate

Interest expense was \$50.7 million and \$129.7 million for the three and nine months ended September 30, 2008, compared with \$23.4 million and \$70.2 million for the corresponding periods in 2007. The increases are primarily the result of higher weighted average debt balance associated with the following debt issuances:

- \$200 million of our Zero Coupon Senior Notes in August 2007,
- \$400 million of our Junior Subordinated Notes in September 2007,

- \$400 million of our 6.5% Senior Notes in April 2008, and
- \$400 million of our 7.5% Senior Notes in April 2008.

Our weighted average interest rate is 6.3% for the three months and 6.0% for the nine months ended September 30, 2008 as compared with our weighted average interest rates of 6.0% and 5.9% for the same periods in 2007.

Further contributing to the increase in interest expense is the \$4.0 million decrease in interest capitalized to our construction projects in the three months ended September 30, 2008 from the same period in 2007. Conversely, the increase in interest expense in the first nine months of 2008 was offset by an additional \$5.6 million of capitalized interest when compared to the same period in 2007. For the three and nine months ended September 30, 2008 and 2007, our interest cost is comprised of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Interest expense	\$50.7	\$23.4	\$129.7	\$70.2
Interest capitalized	6.2	10.2	31.2	25.6
Interest cost incurred	<u>\$56.9</u>	<u>\$33.6</u>	<u>\$160.9</u>	<u>\$95.8</u>

LIQUIDITY AND CAPITAL RESOURCES

Disruption to Functioning of Capital Markets

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to issue debt and equity at prices that are similar to offerings in recent years will be limited over the next three to six months and possibly longer should capital markets remain constrained. Although we intend to move forward with our planned internal growth projects, we may revise the timing and scope of these projects as necessary to adapt to existing economic conditions and the benefits expected to accrue to our unitholders from our expansion activities may be muted by substantial cost of capital increases during this period.

General

We believe that our ability to generate cash flow is sufficient to meet our current and future operating needs. 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 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 commercial paper program and/or our Credit Facility, and lastly, from borrowings under our \$500 million revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. 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. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

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. Although we have generated in excess of \$2.2 billion over the past two years through the issuance of a balanced combination of debt and equity securities to fund our expansion projects, our ability to access these markets to obtain permanent financing over the next three to twelve months is likely to be limited due to prevailing market conditions. Our planned internal growth projects continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them. As a result, we will continue to be opportunistic in our approach to funding the remaining expenditures from additional issuances of our capital and long-term debt.

In March 2008, we obtained approximately \$221.8 million of cash from the public issuance and sale of 4.6 million of our Class A common units at a price to the public of \$49.00 per unit, which consisted of \$217.2 million of net proceeds, after payment of underwriters' discounts, commissions and offering expenses and a contribution of \$4.6 million from our general partner to maintain its two percent general partner interest. Additionally, in early April 2008, we completed the private issuance and sale of our \$400 million Notes due 2018 and our \$400 million Notes due 2038 for net proceeds of approximately \$790.2 million, after payment of initial purchasers' discounts and offering expenses. The Notes due 2018 bear interest at the rate of 6.50% and the Notes due 2038 bear interest at the rate of 7.50%. We used a portion of the proceeds from these offerings to repay outstanding issuances of commercial paper and borrowings under our Credit Facility, which we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs.

Available Credit

Two primary sources of our liquidity are provided by the commercial paper market and our Credit Facility. We have a \$600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that in the past have been generally more competitive than the rates available under our Credit Facility. In addition to our Credit Facility and commercial paper program, we have access to a \$500 million unsecured three year revolving credit agreement from Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc.

Credit markets in the United States and around the world remain constrained due to a lack of liquidity and confidence in a number of financial institutions. Investors continue to seek perceived safe investments in securities of the United States government rather than corporate issues. Although the credit ratings assigned to our senior unsecured debt securities by the nationally recognized statistical ratings organizations are considered "investment grade," we may at times experience difficulty accessing the commercial paper and long-term credit markets due to prevailing market conditions. Additionally, existing constraints in the commercial paper and credit markets may increase the rates we are charged for utilizing these markets. Notwithstanding the continuing weakness in the United States credit markets, we expect that our available liquidity is sufficient to meet our operating and capital requirements into 2009 and for the foreseeable future.

Credit Facility

A subsidiary of Lehman Brothers Holdings, Inc. (“Lehman”), Lehman Brothers Bank, FSB (“Lehman BB”) is one of the committed lenders under our Credit Facility. On September 15, 2008, Lehman filed a petition under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. Lehman BB has declined requests to honor its commitment to lend up to \$82.5 million under our Credit Facility, effectively reducing the amount available to us under our Credit Facility to \$1,167.5 million. We are working with other financial institutions to assume Lehman BB’s commitment. The remaining lenders under our Credit Facility continue to honor our requests for funding and we believe the amounts available to us under our Credit Facility will continue to provide us with sufficient liquidity to meet our working capital needs.

The amounts we can borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At September 30, 2008, we had \$386.2 million outstanding under our Credit Facility at a weighted average interest rate of 3.82% and letters of credit totaling \$101.2 million.

At September 30, 2008, we could borrow \$490.1 million under the terms of our Credit Facility, determined as follows:

	September 30, 2008
	(in millions)
Total credit available under Credit Facility	\$1,250.0
Less: Amounts outstanding under Credit Facility	(386.2)
Balance of letters of credit outstanding	(101.2)
Principal amount of commercial paper issuances	(190.0)
Lehman Brothers Bank, FSB commitment	(82.5)
Total amount we could borrow at September 30, 2008	<u>\$ 490.1</u>

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date of the Credit Facility from April 4, 2012 to April 4, 2013.

Commercial Paper Program

At September 30, 2008, we had \$190 million in principal amount of commercial paper outstanding, with unamortized discount of \$0.5 million, at a weighted average interest rate of 3.19%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately \$79.4 million during the nine months ended September 30, 2008, which include gross issuances of \$1,603.9 million and gross repayments of \$1,683.3 million. At September 30, 2008, we could issue an additional \$410 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

EUS Credit Agreement

In addition to our Credit Facility and commercial paper program, we have access to an unsecured three year revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. (the “EUS Credit Agreement”). The EUS Credit Agreement provides us with access to an additional \$500 million of financing on substantially the same terms as our Credit Facility and matures in December 2010. The amounts available to us under the EUS Credit Agreement remain undrawn at September 30, 2008 and available for our use.

The credit markets, including the commercial paper markets in the United States, have recently experienced adverse conditions. Continuing volatility in the capital markets may increase costs associated with issuing commercial paper or other debt instruments or affect our ability to access those markets. Notwithstanding these adverse market conditions, we currently believe that current cash and cash generated by operations, together with access to external sources of funds as described above, will be sufficient to meet our operating and capital needs in the foreseeable future.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures for the construction of additional natural gas and crude oil transportation infrastructure over the next three years. In 2008, we expect to spend approximately \$1.6 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. Our ability to fund these expenditures is dependent upon our ability to access the capital necessary to finance the construction of these facilities. Capital markets in the United States and abroad are constrained and as a result we may revise the timing and scope of these projects as necessary to adapt to existing markets and economic conditions.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the 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, 2008. Although we anticipate making the indicated expenditures, 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, estimates may change as a result of decisions made at a later date to revise the scope of a project. We made capital expenditures of \$1.0 billion, including \$49.3 million for core maintenance activities, during the nine months ended September 30, 2008.

For the full year of 2008, we anticipate our capital expenditures to approximate the following in billions:

System enhancements	\$0.5
Core maintenance activities	0.1
Southern Access expansion	0.8
Alberta Clipper	0.2
	<u>\$1.6</u>

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our estimated construction cost, actual expenditures through September 30, 2008, the incremental capacity that will become available upon completion of the project and the periods during

which 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 Incremental Capacity			
	Estimated Cost	Actual Expenditures through September 30, 2008	Storage ⁽¹⁾	Oil ⁽²⁾	Natural Gas ⁽³⁾	Expected Completion
	(in billions)					
Southern Access expansion (Lakehead)	\$2.1	\$1.7	—	400	—	2009
Clarity (East Texas)	0.6	0.6	—	—	700	2008
Alberta Clipper	1.2	0.1	—	450	—	Mid-2010
North Dakota phase 6 expansion	0.2	—	—	50	—	Early 2010
Griffith and Superior storage tanks . . .	0.1	—	1,220	—	—	2008
Trailbreaker	0.3	—	—	—	—	2012
Total	<u>\$4.5</u>	<u>\$2.4</u>	<u>1,220</u>	<u>900</u>	<u>700</u>	

⁽¹⁾ Thousands of barrels (KBbl).

⁽²⁾ Thousands of barrels per day (Kbpd).

⁽³⁾ Millions Of cubic feet per day (MMcf/d).

At September 30, 2008, we have approximately \$573.2 million in outstanding purchase commitments for materials and services associated with our capital projects for the construction of assets that we expect to settle during the remainder of 2008 and into 2009. However, we will incur additional commitments as our capital projects continue to progress.

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our Southern Access expansion and Alberta Clipper 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 the issuance of commercial paper or borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. 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 September 30, 2008:

	<u>Notional</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>Total</u>
	(dollars, in millions)							
Swaps								
Natural gas ⁽¹⁾	314,776,128	\$(21.8)	\$(42.0)	\$(41.1)	\$(33.2)	\$(7.0)	\$1.1	\$(144.0)
NGL ⁽²⁾	8,029,873	(18.5)	(43.2)	(7.0)	(0.5)	4.6	—	(64.6)
Crude ⁽²⁾	1,345,324	(5.3)	(11.4)	(7.9)	(7.6)	(5.8)	1.1	(36.9)
Options-calls								
Natural gas ⁽¹⁾	1,187,000	(0.3)	(1.4)	(1.5)	(1.4)	—	—	(4.6)
NGL ⁽²⁾	9,486	—	—	—	—	—	—	—
Options-puts								
Natural gas ⁽¹⁾	1,310,000	0.6	—	—	—	—	—	0.6
NGL ⁽²⁾	1,087,300	0.4	1.0	2.3	1.5	2.6	—	7.8
Totals		<u>\$(44.9)</u>	<u>\$(97.0)</u>	<u>\$(55.2)</u>	<u>\$(41.2)</u>	<u>\$(5.6)</u>	<u>\$2.2</u>	<u>\$(241.7)</u>

(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 nine months ended September 30, 2008 was \$473.2 million, an increase of \$55.3 million from the \$417.9 million generated during the same period in 2007. The increase in operating cash flow is directly attributable to the improved operating performance of our Liquids and Natural Gas systems. Although net cash provided by operating activities increased, cash flows associated with changes in our working capital accounts for the nine months ended September 30, 2008 were lower than the same period of 2007 due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used \$294.8 million less in our investing activities during the nine months ended September 30, 2008 in relation to the same period in 2007. The decrease is primarily attributable to the \$315.8 million reduction of amounts spent in the first nine months of 2008 on our construction projects as compared to the same period of 2007. 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 provided by financing activities during the nine months ended September 30, 2008 was \$707.1 million, compared with \$920.9 million for the corresponding period in 2007. 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 nine months of 2008 when compared to the same period in 2007. Net cash provided by financing activities for the nine months ended September 30, 2008 is attributable to the following:

- \$221.8 million we raised in March 2008 from the issuance of 4.6 million class A common units, which consisted of \$217.2 million of net proceeds after underwriters' discounts, commissions and offering expenses, and a contribution of \$4.6 million from our general partner to maintain its two percent general partner interest.

- In early April 2008, we completed the private issuance and sale of our \$400 million Notes due 2018 and our \$400 million Notes due 2038 for net proceeds of approximately \$790.2 million, after payment of initial purchasers' discounts and offering expenses.

The increase in cash raised from both our unit and debt issuances is partially offset by the following:

- \$93.1 million of net repayments on our Credit Facility and commercial paper.
- \$32.3 million more distributions to our partners for the first nine months of 2008 compared to the same period in 2007 due to a greater number of units outstanding, a higher distribution level and higher incentive distribution payments to our general partner.

For the nine months ended September 30, 2008 we had gross borrowings of \$2,131.3 million under our Credit Facility and gross repayments of \$2,145.0 million, including \$490.0 million of non-cash borrowings and repayments. Under our commercial paper program we had gross issuances of \$1,603.9 million and gross repayments \$1,683.3 million during the first nine months of 2008.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On October 13, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2008. The distribution will be paid to unitholders of record as of November 6, 2008, of our available cash of \$108.8 million at September 30, 2008, or \$0.990 per common unit. Of this distribution, \$74.9 million will be paid in cash, \$14.3 million will be distributed in i-units to our i-unitholder, \$18.9 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 July 1, 2008, we increased our rates for transportation on our Lakehead, North Dakota and Ozark systems in accordance with the indexed rate ceilings allowed by the FERC. In March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, and does not apply to the SEP II, Terrace and Facilities surcharges. Effective July 2008, we increased the base tariff rates on our Lakehead system by an average of 8.2 percent to equal the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is \$1.26 per barrel, which reflects a \$0.05 per barrel increase over the rates filed effective April 1, 2008. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 5.2 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

Effective April 1, 2008, we filed our annual tariff 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 2008. The projected costs for 2008 include four projects including the first stage of the Southern Access mainline expansion, two Superior and Griffith terminal tank projects and the Clearbrook Manifold project. This filing increased the average tariff for crude oil movements from the Canadian

border to Chicago, Illinois, by approximately \$0.34 per barrel, to an average of approximately \$1.21 per barrel. We began 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.

OTHER MATTERS

We amended our limited partnership agreement to modify the mechanism by which the capital accounts of all our partners are maintained when our general partner's incentive distribution rights are considered in determining the fair market value of the Partnership's assets in the event of a follow-on offering of our common units. We do not expect the amendment to materially change the amount of net taxable income or loss allocated to our unitholders or the economic rights of our unitholders as compared with the allocations or economic rights of our general partner.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner; any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the affect this pronouncement will have on our present computation of earnings per unit.

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, 2007, 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 September 30, 2008 and December 31, 2007, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

		At September 30, 2008					At December 31, 2007		
			Wtd. Average Price ⁽²⁾		Fair Value ⁽³⁾		Fair Value ⁽³⁾		
		Commodity	Notional ⁽¹⁾	Receive	Pay	Asset	Liability	Asset	Liability
Contract maturing in 2008									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	8,542,547	\$ 6.20	\$ 7.62	\$ 0.9	\$(13.0)	\$ 7.6	\$(14.5)	
	NGL	30,000	88.10	87.44	0.1	(0.1)	—	—	
Receive fixed/pay variable	Natural Gas	7,670,290	6.68	6.72	8.2	(8.6)	10.3	(39.8)	
	NGL	1,452,036	42.37	55.24	0.5	(19.0)	—	(98.9)	
	Crude Oil	137,824	61.68	100.48	—	(5.3)	—	(17.7)	
Receive variable/pay variable	Natural Gas	51,956,969	6.80	6.98	6.2	(15.5)	7.0	(3.5)	
<i>Options</i>									
Calls (written)	Natural Gas	92,000	4.31	7.62	—	(0.3)	—	(1.3)	
Calls (purchased)	NGL	9,486	53.53	53.19	—	—	—	—	
Puts (purchased)	Natural Gas	215,000	9.05	6.85	0.6	—	—	—	
	NGL	136,896	57.41	46.47	0.4	—	0.1	—	
Contract maturing in 2009									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	16,187,681	\$ 7.47	\$ 8.18	\$ 3.4	\$(14.5)	\$ 5.5	\$ (1.6)	
	NGL	176,870	60.94	63.69	0.1	(0.6)	—	—	
Receive fixed/pay variable	Natural Gas	18,471,215	6.43	7.88	12.4	(38.4)	1.2	(41.8)	
	NGL	3,735,045	46.19	57.94	5.9	(48.6)	—	(43.6)	
	Crude Oil	354,625	69.29	102.46	—	(11.4)	—	(7.2)	
Receive variable/pay variable	Natural Gas	104,153,403	7.68	7.73	5.8	(10.7)	2.9	(1.8)	
<i>Options</i>									
Calls (written)	Natural Gas	365,000	4.31	8.15	—	(1.4)	—	(1.5)	
Puts (purchased)	Natural Gas	365,000	8.15	3.40	—	—	—	—	
	NGL	566,072	55.51	46.00	1.9	(0.9)	0.6	—	
Contract maturing in 2010									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	3,713,769	\$ 8.11	\$ 7.55	\$ 4.5	\$ (2.6)	\$ 4.4	\$ —	
	NGL	45,625	50.59	57.63	—	(0.3)	—	—	
Receive fixed/pay variable	Natural Gas	10,048,870	4.40	8.45	0.7	(39.1)	—	(38.0)	
	NGL	1,513,655	49.12	53.78	7.5	(14.2)	—	(13.8)	
	Crude Oil	332,150	79.29	104.75	1.3	(9.2)	—	(4.4)	
Receive variable/pay variable	Natural Gas	64,375,000	8.30	8.38	0.7	(5.3)	1.5	(0.7)	
<i>Options</i>									
Calls (written)	Natural Gas	365,000	4.31	8.57	—	(1.5)	—	(1.4)	
Puts (purchased)	Natural Gas	365,000	8.57	3.40	—	—	—	—	
	NGL	172,280	59.23	53.37	2.3	—	—	—	
Contract maturing in 2011									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	1,598,755	\$ 8.37	\$ 6.97	\$ 3.3	\$ (1.3)	\$ 3.2	\$ —	
Receive fixed/pay variable	Natural Gas	7,955,920	3.63	8.53	—	(35.3)	—	(34.1)	
	NGL	581,810	55.84	56.81	4.1	(4.6)	—	(4.3)	
	Crude Oil	228,125	68.36	105.35	—	(7.6)	—	(3.4)	
Receive variable/pay variable	Natural Gas	15,885,000	8.63	8.62	0.5	(0.4)	0.1	—	
<i>Options</i>									
Calls (written)	Natural Gas	365,000	4.31	8.54	—	(1.4)	—	(1.4)	
Puts (purchased)	Natural Gas	365,000	8.54	3.40	—	—	—	—	
	NGL	83,220	63.34	51.53	1.5	—	—	—	
Contract maturing in 2012									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	941,709	\$ 8.33	\$ 8.72	\$ 0.9	\$ (1.2)	\$ 0.9	\$ —	
	NGL	36,600	50.28	55.58	—	(0.2)	—	—	
Receive fixed/pay variable	Natural Gas	1,456,000	3.57	9.05	—	(7.0)	—	(6.8)	
	NGL	458,232	70.56	58.26	4.8	—	—	—	
	Crude Oil	219,600	74.85	105.75	—	(5.8)	—	(1.9)	
Receive variable/pay variable	Natural Gas	1,089,000	8.20	7.90	0.3	—	—	—	
<i>Options</i>									
Puts (purchased)	NGL	128,832	66.80	54.10	2.6	—	—	—	
Contract maturing after 2012									
<i>Swaps</i>									
Receive fixed/pay variable	Natural Gas	730,000	\$ 9.83	\$ 8.00	\$ 1.1	\$ —	\$ —	\$ —	
	Crude Oil	73,000	124.05	106.12	1.1	—	—	—	

⁽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 September 30, 2008 and December 31, 2007, 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).

	September 30, 2008	December 31, 2007
	(in millions)	
Counterparty Credit Quality*		
AAA.....	\$ —	\$ —
AA.....	(164.0)	(298.3)
A.....	(76.4)	(47.2)
Lower than A.....	—	—
Total.....	<u><u>\$(240.4)</u></u>	<u><u>\$(345.5)</u></u>

* 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. Our management has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2008. 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, or are reasonably likely to materially affect, our internal control over financial reporting during the three months ended September 30, 2008.

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, 2007.

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.

Global financial markets and economic conditions have been, and continue to be, weak and volatile which has caused 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 risk have made, and will likely continue to make, it difficult to obtain funding for our capital needs from the credit and capital markets on terms similar to recent debt and equity offerings.

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

The commercial paper markets have recently experienced increased volatility and disruption, resulting in higher costs to issue commercial paper, which has resulted in a reduction in our use of our commercial paper program. In addition, because of the recent downturn in the financial markets, including the issues surrounding the solvency of many institutional lenders and the recent failure of several banks, our ability to obtain capital from our Credit Facility may be impaired. For example, as a result of Lehman Brothers Holding, 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, has declined requests to honor its commitment to lend up to \$82.5 million under our Credit Facility, effectively reducing the amount available to us under our Credit Facility to \$1,167.5 million. We may be unable to utilize the full borrowing capacity under our Credit Facility if other lenders are not willing to provide additional funding to make up the portion of the Credit Facility commitments that Lehman BB has refused to fund or if any of the remaining 13 committed lenders is unable or unwilling to fund their respective portion of any funding request we make under our Credit Facility.

Due to these factors, we cannot be certain that 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 or 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.

Our planned construction and development activities require substantial capital. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could delay or curtail our planned construction projects.

We have made and expect to continue making substantial capital expenditures for the construction and development of crude oil and natural gas infrastructure. One of the primary uses of our capital resources is expenditures for our pipeline construction and expansion projects. We invested approximately

\$1.9 billion in 2007 and anticipate investing approximately \$1.6 billion during 2008 on our construction and development activities.

We intend to finance our future capital expenditures initially from our cash flow from operations, second from borrowings under our commercial paper program or our Credit Facility and lastly from borrowings under our \$500 million revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. As of September 30, 2008, our total debt outstanding was \$3,736.3 million, we had \$151.6 million available in unrestricted cash and short-term investments, \$490.1 million of available borrowing capacity under our Credit Facility and the full \$500 million available to us under our revolving credit agreement with Enbridge (U.S.) Inc. We expect to obtain permanent financing through the issuance of additional debt and equity securities, which we will use to repay amounts initially drawn to fund our construction and development activities. We may be unable to issue additional debt or equity securities, or to issue these securities on attractive terms due to a number of factors including a lack of demand, poor economic conditions, unfavorable interest rates or our financial condition or credit rating at the time. In the event additional capital resources are unavailable; we may curtail construction and development activities, or be forced to sell some of our assets on an untimely or unfavorable basis in order to raise capital.

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: October 31, 2008

By: /s/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)

Date: October 31, 2008

By: /s/ MARK A. MAKI

Mark A. Maki
Vice President—Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by an “*”; all exhibits not so designated are incorporated herein by reference to a previous filing as indicated.

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 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 dated 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 dated August 16, 2006).
3.4	Amendment No. 1 to the 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 dated 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 dated August 6, 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 dated October 9, 2001).
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.