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 June 30, 2007

OR

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

For the transition period from to

Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**39-1715850**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, TX 77002
(Address of principal executive offices and zip code)

(713) 821-2000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Large Accelerated Filer ☒ Accelerated Filer ☐ Non-Accelerated Filer ☐

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 55,238,834 Class A common units outstanding as of July 30, 2007.

ENBRIDGE ENERGY PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

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," "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 sales, 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, 2006 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 June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$1,738.7	$1,424.7	$3,451.4	$3,313.3
Operating expenses				
Cost of natural gas (Note 10)	1,475.6	1,185.6	2,959.9	2,833.3
Operating and administrative	105.1	87.3	202.8	161.2
Power	27.3	24.2	57.4	50.5
Depreciation and amortization	39.8	34.0	76.3	66.7
	1,647.8	1,331.1	3,296.4	3,111.7
Operating income	90.9	93.6	155.0	201.6
Interest expense	21.5	27.6	46.8	55.5
Other income	0.5	4.4	1.9	5.4
Income before income tax expense	69.9	70.4	110.1	151.5
Income tax expense (Note 6)	1.3	—	2.4	—
Net income	$ 68.6	$ 70.4	$ 107.7	$ 151.5
Net income allocable to limited partner units (Note 2)	$ 59.3	$ 63.2	$ 90.7	$ 137.1
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.69	$ 0.96	$ 1.10	$ 2.08
Weighted average limited partner units outstanding	86.5	65.9	82.2	65.8

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 June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(unaudited; in millions)			
Net income	$68.6	$ 70.4	$107.7	$151.5
Other comprehensive income (loss) (Note 10)	5.3	(30.3)	(35.0)	3.8
Comprehensive income	$73.9	$ 40.1	$ 72.7	$155.3

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30,	
	2007	2006
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 107.7	$ 151.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	76.3	66.7
Derivative fair value (gains) losses (Note 10)	12.6	(29.4)
Gain on Sale of Assets	(0.2)	—
Inventory market price adjustment	1.5	9.7
Environmental liabilities (Note 9)	(1.0)	0.8
Other	(1.8)	1.0
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	49.4	(33.1)
Due from General Partner and affiliates	5.0	14.2
Accrued receivables	43.5	239.6
Inventory (Note 4)	(3.9)	(26.5)
Current and long-term other assets (Note 10)	(4.5)	(4.3)
Due to General Partner and affiliates	19.7	11.0
Accounts payable and other (Notes 3 and 10)	(14.5)	(7.4)
Accrued purchases	(42.4)	(221.7)
Interest payable	5.3	—
Current income tax payable (Note 6)	2.3	—
Property and other taxes payable	3.7	(5.1)
Net cash provided by operating activities	258.7	167.0
Cash used in investing activities		
Additions to property, plant and equipment	(891.5)	(285.2)
Changes in construction payables	87.2	4.8
Asset acquisitions, net of cash acquired	—	(33.2)
Proceeds from Sales of Assets	0.9	—
Other	(2.0)	0.1
Net cash used in investing activities	(805.4)	(313.5)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 8)	628.8	—
Distributions to partners (Note 8)	(115.8)	(113.2)
Net borrowings from Credit Facility (Note 7)	—	10.0
Net issuances (repayments) of commercial paper (Note 7)	(46.5)	269.1
Repayment on affiliate loan	—	(20.0)
Net cash provided by financing activities	466.5	145.9
Net decrease in cash and cash equivalents	(80.2)	(0.6)
Cash and cash equivalents at beginning of year	184.6	89.8
Cash and cash equivalents at end of period	$ 104.4	$ 89.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2007	December 31, 2006
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 104.4	$ 184.6
Receivables, trade and other, net of allowance for doubtful accounts of $1.7 in 2007 and $2.4 in 2006	97.2	146.7
Due from General Partner and affiliates	25.5	30.5
Accrued receivables	473.0	516.5
Inventory (Note 4)	119.5	117.1
Other current assets (Note 10)	15.8	13.9
	835.4	1,009.3
Property, plant and equipment, net (Note 5)	4,641.9	3,824.9
Other assets, net (Notes 6 and 10)	36.2	26.1
Goodwill	265.7	265.7
Intangibles, net	97.3	97.8
	$5,876.5	$5,223.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 42.3	$ 22.6
Accounts payable and other (Notes 3 and 10)	314.0	211.5
Accrued purchases	487.9	530.3
Interest payable	12.1	11.4
Property and other taxes payable (Note 6)	23.8	18.6
Loans from General Partner and affiliates	140.8	136.2
Current maturities of long-term debt	31.0	31.0
	1,051.9	961.6
Long-term debt (Note 7)	2,015.8	2,066.1
Environmental liabilities (Note 9)	3.7	3.3
Other long-term liabilities (Note 10)	176.0	149.4
	3,247.4	3,180.4
Commitments and contingencies (Note 9)		
Partners' capital (Note 8)		
Class A common units (Units issued—55,238,834 in 2007 and 49,938,834 in 2006)	1,370.2	1,141.7
Class B common units (Units issued—3,912,750 in 2007 and 2006)	74.9	67.6
Class C units (Units issued—17,459,447 in 2007 and 11,070,152 in 2006)	850.2	509.8
i-units (Units issued—13,108,074 in 2007 and 12,674,148 in 2006)	497.5	466.3
General Partner	60.9	47.6
Accumulated other comprehensive loss (Note 10)	(224.6)	(189.6)
	2,629.1	2,043.4
	$5,876.5	$5,223.8

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

We have prepared the accompanying unaudited interim consolidated financial statements 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 at June 30, 2007 and December 31, 2006; our results of operations and comprehensive income for the three and six month periods ended June 30, 2007 and 2006; and our cash flows for the six month periods ended June 30, 2007 and 2006. We derived the Consolidated Statement of Financial Position as of December 31, 2006, from the audited financial statements included in our 2006 Annual Report on Form 10-K.

The results of operations for the three and six month periods ended June 30, 2007, 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 consolidated statements of cash flows for the period ended June 30, 2006 include reclassifications that were made to present changes in environmental liabilities separately from changes in Accounts payable and other, consistent with our current period presentation. Additionally, we reclassified $6.4 million from “Other assets, net” to “Intangibles, net” in our December 31, 2006 consolidated statement of financial position related to rights we received for contributions we made in aid of construction projects, consistent with our current period presentation. These reclassifications have no effect on previously reported results of operations, comprehensive income or partners’ capital. 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, 2006.

2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after deduction of Enbridge Energy Company, Inc.'s (the "General Partner") allocation, 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 June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(in millions, except per unit amounts)			
Net income	$68.6	$70.4	$107.7	$151.5
Allocations to the General Partner:				
Net income allocated to the General Partner	(1.4)	(1.4)	(2.2)	(3.0)
Incentive income allocated to the General Partner	(7.9)	(5.7)	(14.7)	(11.3)
Historical cost depreciation adjustments	—	(0.1)	(0.1)	(0.1)
	(9.3)	(7.2)	(17.0)	(14.4)
Net income allocable to limited partner units	$59.3	$63.2	$ 90.7	$137.1
Weighted average limited partner units outstanding	86.5	65.9	82.2	65.8
Net income per limited partner unit (basic and diluted)	$0.69	$0.96	$ 1.10	$ 2.08

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 of approximately $31.8 million at June 30, 2007 and $46.9 million at December 31, 2006, are included in Accounts payable and other on the Consolidated Statements of Financial Position.

4. INVENTORY

Inventory is comprised of the following:

	June 30, 2007	December 31, 2006
	(in millions)	
Material and supplies	$ 3.9	$ 3.8
Liquids inventory	9.8	9.9
Natural gas and natural gas liquids inventory	105.8	103.4
	$119.5	$117.1

Our inventory at June 30, 2007 is net of charges of $1.5 million we recorded to reduce the cost basis of our natural gas and natural gas liquids, or NGLs, inventory to reflect market value. The lower of cost or market adjustments are included in Cost of natural gas on our Consolidated Statements of Income.

5. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	June 30, 2007	December 31, 2006
	(in millions)	
Land	$ 14.8	$ 14.3
Rights-of-way	306.5	298.6
Pipelines	2,385.3	2,320.8
Pumping equipment, buildings and tanks	774.2	747.4
Compressors, meters, and other operating equipment	438.2	418.1
Vehicles, office furniture and equipment	121.3	112.4
Processing and treating plants	140.8	86.4
Construction in progress	1,435.8	733.6
Total property, plant and equipment	5,616.9	4,731.6
Accumulated depreciation	(975.0)	(906.7)
Net property, plant and equipment	$4,641.9	$3,824.9

6. INCOME TAXES

We are not a taxable entity for U.S. federal income tax purposes, or for the majority of states that impose income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income. In May 2006, the State of Texas enacted substantial changes to its tax structure to impose a new tax based on modified gross margin, which began in 2007. Under the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*, we have determined that this tax is an income tax. Our income tax expense is $1.3 million and $2.4 million for the three and six month periods ended June 30, 2007, which we computed by applying a 0.56% apportioned state income tax rate to taxable margin, as defined in the State of Texas statutes. At June 30, 2007 we have included a current income tax payable of $2.4 million in Property and other taxes payable and a deferred income tax asset of $0.4 million in Other assets, net on our Consolidated Statements of Financial Position.

7. DEBT

Credit Facility

At June 30, 2007 and December 31, 2006, we had no amounts outstanding under our Credit Facility and had letters of credit totaling $90.0 million and $59.3 million, respectively. 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. At June 30, 2007, we could borrow $765.0 million under the terms of our Credit Facility without consideration to additional borrowings under our commercial paper program.

On April 4, 2007 we entered into the Second Amended and Restated Credit Agreement (Credit Facility) which among other things: (i) increases the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion; (ii) gives us the right to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion; (iii) eliminates the sublimit on letters of credit; (iv) provides for a five-year facility that matures April 4, 2012 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity; (v) modifies our leverage ratio to include in the calculations of EBITDA (as defined in the Second Amended and Restated Credit Agreement) pro forma adjustments for material projects and to exclude from the calculation of Consolidated Funded Debt (as defined in the Second Amended and Restated Credit Agreement) certain amounts of preferred securities and subordinated debt that we or our designated subsidiaries may issue in the future; and (vi) eliminates our coverage ratio financial covenant. Our Credit Facility continues to support our commercial paper program.

Commercial Paper Program

Under the terms of our commercial paper program, we can issue up to $600 million of commercial paper. At June 30, 2007, we had outstanding $393.3 million of commercial paper, net of unamortized discount of $1.7 million, bearing interest at a weighted average rate of 5.48%. At December 31, 2006, we had $443.7 million of commercial paper outstanding, net of $1.3 million of unamortized discount, at a weighted average interest rate of 5.45%. At June 30, 2007, we could issue an additional $205.0 million in principal amount under the terms of our commercial paper program.

8. 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 six months ended June 30, 2007:

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
					(in millions, except per unit amounts)			
January 26, 2007	February 14, 2007	February 6, 2007	$0.925	$80.0	$11.7	$10.2	$0.5	$57.6
April 26, 2007	May 15, 2007	May 7, 2007	$0.925	$86.6	$11.9	$15.9	$0.6	$58.2

(1) During 2007, in lieu of cash distributions, the Partnership issued 433,926 i-units to Enbridge Management.

(2) During 2007, in lieu of cash distributions, the Partnership issued 458,503 Class C units to our Class C unitholders.

(3) The Partnership retains an amount equal to two percent of the i-unit and Class C unit distribution from the General Partner in respect of its two percent general partner interest.

Issuance of Class A common units

In May 2007, we issued 5.3 million Class A common units at a price of $58.00 per unit, for proceeds of approximately $301.9 million, net of underwriters' discounts, commissions and issuance costs. In addition, our general partner contributed approximately $6.1 million to us to maintain its two percent general partner interest. We used the proceeds from this offering partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion projects. We invested the remaining amount in short-term commercial paper for use in future periods to fund additional expenditures under our capital expansion projects.

Private Placement of Class C Units

In April 2007, we issued and sold 4.7 million Class C units at a price of $53.11 per Class C unit to CDP Infrastructure Fund G.P. ("CDP"), 0.9 million Class C units to Tortoise Infrastructure Corporation and 0.3 million Class C units to Tortoise Energy Capital Corporation. We sold the Class C units in a private transaction exempt from registration under Section 4(2) of the Securities Act. We received proceeds of approximately $314.4 million, net of expenses associated with the private placement. In addition, our general partner contributed approximately $6.4 million to us to maintain its two percent general partner interest. We used the proceeds from this offering partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion program, including the East Texas and Southern Access expansion projects.

9. COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to the gathering, transportation, storage and processing of liquid hydrocarbon and natural gas products 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.

As of June 30, 2007 and December 31, 2006, we have recorded $2.7 million and $4.1 million, respectively, in current liabilities and $3.7 million and $3.3 million, respectively, in long-term liabilities, primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

In January 2007, we detected a leak on Line 14 of our Lakehead system, near the Owen, Wisconsin pump station. We immediately shut the pipeline down and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We spent approximately $0.9 million to recover the barrels released, complete excavation, clean-up and repairs to return the line to service. We have applied pressure restrictions to the line as we work with federal and state environmental and pipeline safety regulators to investigate the cause of the rupture. Such pressure restrictions have not materially affected throughput on the system. We have the potential of incurring additional expenditures to remediate any condition on the line that is determined to have caused the rupture.

In February 2007, a contractor undertaking work in Rusk County, Wisconsin on the Enbridge Southern Lights project punctured the adjacent Line 14 pipeline, resulting in a release of crude oil estimated at 3,000 barrels. As the spill was largely contained within the ditch used for construction, environmental impact was minimized. Impact to customers was also minimized as the line was repaired and returned to service in less than two days. We continue investigating this incident and have spent approximately $1.4 million of the estimated $2.6 million associated with the repair and cleanup, which we recorded as a liability and a receivable, since we will recover these cost from the parties responsible for the damage. Any further exposure or impact related to this incident is not believed to be material.

Legal Proceedings

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

10. DERIVATIVE FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

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

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive, other than in a forced or liquidation sale, to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded in our Consolidated Statements of Income as increases and decreases in Cost of natural gas for our commodity-based derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

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

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. As discussed in Note 15 to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2006, we have four transaction types where the hedge structure does not meet the requirements to permit application of hedge accounting and are referred to as "non-qualified." Non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated financial instrument contract settlement is made.

The following table presents the mark-to-market gains and losses associated with changes in the fair value of our commodity price derivative financial 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 Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
	(in millions)			
Natural Gas segment				
Ineffectiveness	$ 0.2	$ (0.1)	$ 0.3	$ (0.1)
Non-qualified hedges	(2.8)	(3.6)	(6.0)	(1.8)
Marketing				
Non-qualified hedges	6.3	5.4	(6.9)	31.3
Derivative fair value gains (losses)	$ 3.7	$ 1.7	$ (12.6)	$ 29.4

We record the change in fair value of our cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified from AOCI to earnings. Also included in AOCI are unrecognized losses of approximately $3.4 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 six month periods ended June 30, 2007, we reclassified losses of $21.0 million and $37.2 million, respectively, from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled. For the three and six month periods ended June 30, 2006, we reclassified losses of $14.9 million and $39.7 million, respectively, from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

Derivative Positions

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	June 30, 2007	December 31, 2006
	(in millions)	
Other current assets	$ 5.1	$ 7.2
Other assets, net	20.8	11.0
Accounts payable and other	(87.8)	(57.2)
Other long-term liabilities	(162.3)	(136.4)
	$ (224.2)	$ (175.4)

The increase in our obligation associated with derivative activities is primarily due to the increase in forward natural gas prices from December 31, 2006 to June 30, 2007. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas sales and purchase agreements.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated "BBB+" or better by the major credit rating agencies.

11. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present financial information about our business segments:

	As of and for the three months ended June 30, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$129.4	$1,384.4	$954.3	$ —	$2,468.1
Less: Intersegment revenue	—	670.1	59.3	—	729.4
Operating revenue	129.4	714.3	895.0	—	1,738.7
Cost of natural gas (Notes 5 and 10)	—	591.8	883.8	—	1,475.6
Operating and administrative	40.6	60.9	1.9	1.7	105.1
Power	27.3	—	—	—	27.3
Depreciation and amortization (Note 6)	16.7	22.4	0.7	—	39.8
Operating income	44.8	39.2	8.6	(1.7)	90.9
Interest expense	—	—	—	21.5	21.5
Other income	—	—	—	0.5	0.5
Income before income tax expense	44.8	39.2	8.6	(22.7)	69.9
Income tax expense	—	—	—	1.3	1.3
Net income	$ 44.8	$ 39.2	$ 8.6	$(24.0)	$ 68.6
Capital expenditures (excluding acquisitions)	$270.2	$ 219.2	$ 0.3	$ 2.5	$ 492.2

(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 three months ended June 30, 2006				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 124.9	$1,231.3	$ 667.6	$ —	$2,023.8
Less: Intersegment revenue	—	557.8	41.3	—	599.1
Operating revenue	124.9	673.5	626.3	—	1,424.7
Cost of natural gas	—	566.9	618.7	—	1,185.6
Operating and administrative	35.1	50.0	1.5	0.7	87.3
Power	24.2	—	—	—	24.2
Depreciation and amortization	15.9	17.9	0.1	0.1	34.0
Operating income	49.7	38.7	6.0	(0.8)	93.6
Interest expense	—	—	—	27.6	27.6
Other income	—	—	—	4.4	4.4
Net income	$ 49.7	$ 38.7	$ 6.0	$ (24.0)	$ 70.4
Capital expenditures (excluding acquisitions)	$ 34.4	$ 148.0	$ 0.5	$ 3.6	$ 186.5

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

	As of and for the six months ended June 30, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 262.2	$2,708.7	$1,843.7	$ —	$4,814.6
Less: Intersegment revenue	—	1,238.9	124.3	—	1,363.2
Operating revenue	262.2	1,469.8	1,719.4	—	3,451.4
Cost of natural gas (Notes 5 and 10)	—	1,255.0	1,704.9	—	2,959.9
Operating and administrative	74.3	122.2	3.5	2.8	202.8
Power	57.4	—	—	—	57.4
Depreciation and amortization (Note 6)	33.1	42.4	0.8	—	76.3
Operating income	97.4	50.2	10.2	(2.8)	155.0
Interest expense	—	—	—	46.8	46.8
Other income	—	—	—	1.9	1.9
Income before income tax expense	97.4	50.2	10.2	(47.7)	110.1
Income tax expense	—	—	—	2.4	2.4
Net income	$ 97.4	$ 50.2	$ 10.2	$ (50.1)	$ 107.7
Total assets	$2,279.0	$3,074.0	$ 353.1	$170.4	$5,876.5
Capital expenditures (excluding acquisitions)	$ 493.4	$ 385.9	$ 1.5	$ 10.7	$ 891.5

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

	As of and for the six months ended June 30, 2006				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 247.5	$2,833.2	$1,634.0	$ —	$4,714.7
Less: Intersegment revenue	—	1,288.7	112.7	—	1,401.4
Operating revenue	247.5	1,544.5	1,521.3	—	3,313.3
Cost of natural gas	—	1,340.4	1,492.9	—	2,833.3
Operating and administrative	63.7	93.7	2.6	1.2	161.2
Power	50.5	—	—	—	50.5
Depreciation and amortization	31.8	34.5	0.2	0.2	66.7
Operating income	101.5	75.9	25.6	(1.4)	201.6
Interest expense	—	—	—	55.5	55.5
Other income	—	—	—	5.4	5.4
Net income	$ 101.5	$ 75.9	$ 25.6	$ (51.5)	$ 151.5
Total assets	$1,704.7	$2,421.6	$ 276.5	$ 85.1	$4,487.9
Capital expenditures (excluding acquisitions)	$ 50.8	$ 229.1	$ 0.9	$ 4.4	$ 285.2

(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.

12. SUBSEQUENT EVENT

Distribution to Partners

On July 27, 2007, the Board of Directors of Enbridge Management declared a distribution payable to our partners on August 14, 2007. The distribution will be paid to unitholders of record as of August 6, 2007, of our available cash of $92.6 million at June 30, 2007, or $0.925 per common unit. Of this distribution, $63.7 million will be paid in cash, $12.1 million will be distributed in i-units to our i-unitholder, $16.2 million will be distributed in Class C units to the holders of our Class C units and $0.6 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

13. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities.* This statement provides companies with an option to report certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to reduce the volatility in earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007 as we have elected not to early adopt the provisions of SFAS No. 159. We do not expect our adoption of SFAS No. 159 to have a material affect on our Consolidated Financial Statements.

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 Quarterly Report on Form 10-Q and with the information included in our Annual Report on Form 10-K for the year ended December 31, 2006.

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
- Providing 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.

We primarily provide fee-based services to our customers to minimize our exposure to commodity price risks. However, in our natural gas and marketing businesses, a portion of our earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure and to provide stability to our cash flow, we enter into derivative financial instrument transactions. Certain of these transactions qualify for hedge accounting under SFAS No. 133, *Accounting for Derivative Transactions and Hedging Activities*; some, however, must be accounted for using the mark-to-market method of accounting and this can expose our earnings to significant volatility.

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

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(in millions)			
Operating Income				
Liquids	$44.8	$49.7	$ 97.4	$101.5
Natural Gas	39.2	38.7	50.2	75.9
Marketing	8.6	6.0	10.2	25.6
Corporate, operating and administrative	(1.7)	(0.8)	(2.8)	(1.4)
Total Operating Income	90.9	93.6	155.0	201.6
Interest expense	21.5	27.6	46.8	55.5
Other income	0.5	4.4	1.9	5.4
Income tax expense	1.3	—	2.4	—
Net Income	$68.6	$70.4	$107.7	$151.5

Summary Analysis of Operating Results

Liquids

Our Liquids segment produced operating income of $44.8 million and $97.4 million for the three and six month periods ended June 30, 2007, a slight decrease compared to the $49.7 million and $101.5 million earned in the comparable periods of 2006. The operating income of our Liquids business was impacted by increases in the average tariffs on all three of our Liquids systems that went into effect July 1, 2006, coupled with annual tariff rate adjustments in April 1, 2007 for historical pipeline expansions known as the SEP II, Terrace and Facilities surcharges. Operating income was also positively affected by the increase in contract storage fees generated by our Cushing terminal associated with the additional storage tanks we completed in late 2006. Operating income for the quarter was negatively affected by lower delivery volumes associated with scheduled and unscheduled third-party upgrader and refinery turnarounds during the quarter. Higher operating expenses, primarily associated with our pipeline integrity management program in addition to higher utility rates, also contributed to lower operating income.

Natural Gas

Operating income from our Natural Gas segment slightly increased by $0.5 million to $39.2 million for the three month period ended June 30, 2007, from $38.7 million for the comparable period in 2006. Operating income for the six month period ended June 30, 2007 decreased by $25.7 million to $50.2 million, from $75.9 million for the comparable period in 2006.

For the three months ended June 30, 2007 the change in contribution from our Natural Gas segment is primarily attributable to the following:

- Increased natural gas treating and processing capacity from the completion of the initial phase of our East Texas expansion and increased processing capacity on our Anadarko system.
- Volume growth within our North Texas systems due to significant production increases and strong drilling activity in the Barnett Shale formation.
- Partially offsetting the volume growth and increased processing and treating capacity were lower revenue less cost of natural gas derived from our processing assets due to a less favorable pricing environment in the current quarter than in the same period of 2006.
- Increased operating and administrative costs associated with the increase in volumes and expansion of our natural gas systems as well as pipeline integrity management costs.

For the six months ended June 30, 2007, in addition to the factors discussed above, the operating results of our Natural Gas segment were also affected by the following:

- An increase in natural gas measurement losses on two of our major gathering systems.
- Operational inefficiencies at our Zybach plant, in part caused by fouling of the plant by contaminated water in the natural gas stream, which reduced NGL production and the associated processing revenue.

Marketing

Operating income from our Marketing segment increased by $2.6 million to $8.6 million for the three month period ended June 30, 2007, from $6.0 million for the comparable period in 2006. Operating income for the six month period ended June 30, 2007 decreased by $15.4 million to $10.2 million, from $25.6 million for the comparable period in 2006. The operating results of our Marketing segment are predominantly the result of the following factors:

- Increased access to preferred natural gas markets associated with our natural gas system expansions and other initiatives, as well as stronger pricing for natural gas in secondary markets.
- Unrealized, non-cash mark-to-market net gains of $6.3 million and net losses of $6.9 million for the three and six month periods ended June 30, 2007, respectively, that resulted from the changes in market value of our derivative financial instruments that do not qualify for hedge accounting.
- Sales of natural gas inventory for approximately $12 million that we realized for the six months ended June 30, 2007, including approximately $6 million of gains from the settlement of derivative financial instruments hedging our natural gas inventory.

Derivative Transactions and Hedging Activities

We record all derivative financial instruments in the consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133. For those derivative financial instruments that do not qualify for hedge accounting, all changes in fair market value are recorded through our Consolidated Statements of Income each period. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, although that is not our intent.

The unrealized, mark-to-market gains for the three month period ended June 30, 2007 are the result of a decline in the forward and daily prices of natural gas and NGLs from March 31, 2007. The unrealized mark-to-market losses for the six month periods ended June 30, 2007, are the result of increases in the forward and daily market prices of natural gas and NGLs from December 31, 2006. The changes in fair value of our portfolio of commodity-based derivative financial instruments that do not qualify for hedge accounting are a result of the volatility in the underlying prices for natural gas, NGLs and crude oil. For the three and six month periods ended June 30, 2006, declining forward and daily prices of natural gas and NGLs produced unrealized, mark-to-market gains in our portfolio of commodity derivative financial instruments. While the natural gas and NGL pricing environment continues to remain volatile, the mark-to-market gains and losses created by this volatility do not affect our cash flow. We expect these non-cash gains and losses to be offset in future quarters as we settle the derivative financial instruments and the underlying physical transactions.

The following table presents the unrealized, non-cash, mark-to-market gains and losses by segment, associated with our derivative financial instruments:

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(unaudited, in millions)			
Natural Gas segment				
Ineffectiveness	$ 0.2	$(0.1)	$ 0.3	$ (0.1)
Non-qualified hedges	(2.8)	(3.6)	(6.0)	(1.8)
Marketing				
Non-qualified hedges	6.3	5.4	(6.9)	31.3
Derivative fair value gains (losses)	$ 3.7	$ 1.7	$(12.6)	$29.4

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 June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(unaudited, in millions)			
Operating Results				
Operating revenues	$129.4	$124.9	$262.2	$247.5
Operating and administrative	40.6	35.1	74.3	63.7
Power	27.3	24.2	57.4	50.5
Depreciation and amortization	16.7	15.9	33.1	31.8
Operating expenses	84.6	75.2	164.8	146.0
Operating Income	$ 44.8	$ 49.7	$ 97.4	$101.5
Operating Statistics				
Lakehead system:				
United States(1)	1,138	1,186	1,192	1,173
Province of Ontario(1)	340	296	338	322
Total Lakehead system deliveries(1)	1,478	1,482	1,530	1,495
Barrel miles (billions)	97	94	200	194
Average haul (miles)	722	699	722	719
Mid-Continent system deliveries(1)	248	260	245	248
North Dakota system:				
Trunkline	92	86	89	84
Gathering	6	6	6	7
Total North Dakota system deliveries(1)	98	92	95	91
Total Liquids Segment Delivery Volumes(1)	1,824	1,834	1,870	1,834

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

Three months ended June 30, 2007 compared with three months ended June 30, 2006

Our Liquids segment accounted for $44.8 million of operating income during the three months ended June 30, 2007, a decrease of $4.9 million from the $49.7 million generated during the same period in 2006. Although the operating revenues of our Liquids business for the second quarter of 2007 were greater than the comparable period of 2006, they were more than offset by increases in operating expenses primarily associated with our pipeline integrity management program and power usage.

Operating revenue for the three months ended June 30, 2007 increased by approximately $4.5 million to $129.4 million from $124.9 million for the same period in 2006. The increase in revenue is predominantly the result of the increase in average tariffs on all three of our Liquids systems associated with the annual index rate increase that went into effect July 1, 2006. Additionally, new tariff rates went into effect April 1, 2007, on our Lakehead system to reflect the annual calculation of the SEP II and other surcharges based on true-ups of prior year amounts and estimates for 2007, as well as an adjustment for the Terrace surcharge due to lower than expected volumes moving on the Lakehead system in 2006. These combined tariff increases and longer hauls contributed an additional $3.5 million to our revenues for the three months ended June 30, 2007. Also contributing to the increase in revenues for the three months ended June 30, 2007, was an increase in contract storage fees generated by our Cushing terminal from the additional storage tanks we placed in service in late 2006.

Delivery volumes on our Liquids systems declined from 1.834 million Bpd during the three months ended June 30, 2006 to 1.824 million Bpd during the same period in 2007. The reduction of delivery volumes on our Lakehead system are primarily due to scheduled and unscheduled maintenance performed by producers on their upgrader facilities and, to a lesser extent, downstream refinery outages in the Midwest United States. We expect the decline in delivery volumes on our Lakehead system to reverse during the second half of 2007 when the maintenance activities being performed by our upstream and downstream customers are expected to be complete. Our Mid-Continent system continues to operate near capacity, although throughput has declined to accommodate the transportation of more heavy crude. Partially offsetting the lower volumes on our Lakehead and Mid-Continent systems is the volume growth on our North Dakota system resulting from completion of our hydrostatic testing program in the third quarter of 2006, which allowed us to increase the capacity of the system.

Operating and administrative expenses for the Liquids segment increased $5.5 million for the three months ended June 30, 2007, compared with the same period in 2006. The increase is driven primarily by higher costs we incurred in connection with our pipeline integrity management program and to a lesser extent by higher oil measurement losses and by workforce related costs associated with the operational, administrative, regulatory and compliance support services necessary for our systems. Also contributing to the increase in operating costs are property taxes, which were lower in 2006 due to favorable settlements of prior year property tax assessments that we realized in that year.

Power costs increased $3.1 million to $27.3 million in the second quarter of 2007, compared with $24.2 million for the same period in 2006, primarily due to the higher utility rates we are charged by our power suppliers.

Six months ended June 30, 2007 compared with six months ended June 30, 2006

Our Liquids segment accounted for $97.4 million of operating income during the six months ended June 30, 2007, representing a $4.1 million decrease over the $101.5 million for the same period in 2006. The components comprising our operating income changed during the six months ended June 30, 2007 compared with the six months ended June 30, 2006, primarily for the same reasons as noted above in the three-month analysis. In addition, however, operating revenues also increased as a result of increased delivery volumes during the first six months of 2007 over the comparable period of 2006, due to upgrader expansions that were completed in the second half of 2006. These additional delivery volumes in the first six months of 2007 also contributed to additional power costs in relation to the first six months of 2006.

Future Prospects Update for Liquids

We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States.

Partnership Projects

Southern Access

In conjunction with Enbridge, we continue to progress on schedule with construction of the 400,000 Bpd Southern Access expansion project. We are undertaking the United States portion of the expansion on our Lakehead system. The first stage of construction, which is on schedule for completion in early 2008, will add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. This stage of the project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment.

The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in early 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. In April 2007, the Illinois Commerce Commission approved and allowed the project to exercise the right of eminent domain if necessary to secure rights-of-way for the project.

As a result of the escalation of costs we have experienced with the first stage of the project for labor, materials and rights-of-way, we are revising our estimated cost to complete the project. We anticipate the ultimate cost to complete our portion of this project to approximate $1.8 billion. The risk to our unitholders resulting from the escalation of costs is largely mitigated by the cost of service tolling arrangement used for this project. Approximately 88 percent of the cost overage will be included in the rate base, which forms the basis for determining our tariff rates for transportation. The remaining 12 percent of the project cost relates to installing larger pipe than required under current agreements which we are financing in anticipation of future expansion opportunities.

Alberta Clipper

Based on forecasts of oil sands production growth developed by Enbridge, as well as forecasts by the Canadian Association of Petroleum Producers, or CAPP, we believe that there will be a need for additional export pipeline capacity out of Western Canada over and above projects currently under development. As a result of this analysis and support received from shippers, we and Enbridge are planning to develop the Alberta Clipper project. This project will involve 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. 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 $1.0 billion, in 2007 dollars, excluding capitalized interest. Alberta Clipper is expected to be in service by mid-2010.

In May 2007, Enbridge filed an application with Canada's National Energy Board, or NEB, for the construction and operation of the Canadian segment of the project. In June 2007 Enbridge filed supplements to this application setting forth the tolling principles for the Canadian portion of the project, which are supported by CAPP. We plan to file a similar set of toll principles with the Federal Energy Regulatory Commission ("FERC"). The project remains subject to regulatory approvals and receipt of various permits in Canada and the United States. Enbridge is progressing with land access, engineering and initial procurement commitments to facilitate commencement of project construction.

North Dakota

Work continues to progress for a fourth quarter 2007 completion of our previously announced North Dakota system expansion. North Dakota Public Service Commission approvals have been obtained for all phases of the project which will add approximately 30,000 Bpd of mainline throughput capacity and expand the system's feeder segment by approximately 30,000 Bpd at an estimated cost of $0.1 billion.

Regional producers in the Williston basin areas of Montana and North Dakota have continued to express interest in further expansion of pipeline capacity on the North Dakota system. As a result, we initiated a binding "Open Season" in June 2007 for 10-year capacity commitments for our proposed Phase 6 expansion project. The proposed $0.13 billion Phase 6 expansion, if fully subscribed, would increase system capacity to 155,000 Bpd, from the 110,000 Bpd of capacity we expect will be available by year-end 2007. Should interest for incremental capacity on the North Dakota system exceed the available firm capacity offered through the Open Season, we will work with shippers to plan for further expansion of the system capacity. The "Open Season" will end at noon August 3, 2007, following which we will evaluate whether to proceed with this proposed expansion project.

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 an approximate capacity of 360,000 barrels each that are scheduled for completion in the second half of 2007 and two additional tanks each with an approximate capacity of 250,000 barrels each to be completed during 2008.

Mid-Continent Terminal Storage

We continue to experience strong interest from customers in securing access to long-term contract storage capacity at our Cushing, Oklahoma terminal. During 2006, we obtained commitments and initiated construction of an additional 5.0 million barrels of storage tanks, 1.1 million barrels of which were completed in late December 2006. During the first half of 2007 we have completed construction of three additional storage tanks with approximately 1.1 million barrels of capacity. The remaining 2.8 million barrels of capacity will be completed during 2007 at an expected cost of $53 million. Once complete our total Mid-Continent terminal capacity will be approximately 16.7 million barrels, which includes 1.4 million barrels of operational storage. This capacity will increase operational tankage available to support our Mid-Continent liquids pipeline systems, and available contract storage.

Enbridge and Other Projects

Spearhead Pipeline

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Chicago to Cushing. The pipeline, renamed Spearhead, began delivering Canadian crude oil to the major oil hub at Cushing in March 2006 and has operated at or near its capacity of 125,000 Bpd. We have benefited from Western Canadian crude oil being carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. On March 2, 2007, Enbridge initiated a binding open season for expansion of the pipeline to 190,000 Bpd, which was successfully concluded in late April with receipt of binding commitments for capacity in excess of 30,000 Bpd. This project will be complementary to our Lakehead system and Enbridge is targeting completion in early 2009.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and CAPP for its 36-inch diameter Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project is scheduled for completion in the first quarter of 2009 and will be undertaken by Enbridge; however, we will benefit through incremental volumes moving through our Lakehead system to reach this extension. Enbridge expects to file a petition for declaratory order with the FERC in August 2007 to address tolling matters and should allow the project to proceed on schedule.

Southern Lights

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago, Illinois to Edmonton, Alberta 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 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 shipments, which will be facilitated by the diluent line.

This project is expected to be in service during 2010. Enbridge has filed applications with the NEB for approval of all facets of the Canadian portion of the project and the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. Enbridge expects to file a FERC petition for declaratory order with respect to tolling matters in the near future. In conjunction with the Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right of way in Illinois. Early construction and right-of-way acquisition related to this project continues in tandem with stage one of the Southern Access project.

United States Gulf Coast Access

In June 2007, Enbridge and ExxonMobil Pipeline Company announced they are jointly assessing the possibility of building a crude oil pipeline from Patoka, Illinois to Beaumont, Texas and through to Houston. This pipeline project is in the initial stages, and Enbridge and ExxonMobil are in discussions with potential shippers regarding the scope, timing, and value of the project. Construction of this project would complement our Lakehead system and further support its expansion.

Eastern PADD II Access

Enbridge has held discussions with several refiners in the eastern United States to gauge interest in supporting the development of a pipeline to provide incremental pipeline capacity to this market. A project of this nature would be complementary to our Lakehead system.

We and Enbridge believe that the Southern Access Expansion Program, the Alberta Clipper Project, and other initiatives to provide access to new markets in the Midwest, Mid-continent and Gulf Coast, offer flexible solutions to future transportation requirements of western Canadian crude oil producers, and the in-service timing of these solutions is in line with prospective shipper needs.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in millions of British Thermal units per day, or MMBtu/d, of natural gas for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(unaudited, in millions)			
Operating Results				
Operating revenues	$ 714.3	$ 673.5	$ 1,469.8	$ 1,544.5
Cost of natural gas	591.8	566.9	1,255.0	1,340.4
Operating and administrative	60.9	50.0	122.2	93.7
Depreciation and amortization	22.4	17.9	42.4	34.5
Operating expenses	675.1	634.8	1,419.6	1,468.6
Operating Income	$ 39.2	$ 38.7	$ 50.2	$ 75.9
Operating Statistics (MMBtu/d)				
East Texas	1,190,000	1,012,000	1,162,000	966,000
Anadarko	588,000	568,000	585,000	565,000
North Texas	352,000	283,000	336,000	281,000
UTOS	191,000	188,000	158,000	193,000
MidLa	131,000	131,000	120,000	107,000
AlaTenn	33,000	34,000	46,000	44,000
KPC	26,000	27,000	32,000	37,000
Bamagas	114,000	83,000	115,000	60,000
Other major intrastates[1]	251,000	217,000	259,000	218,000
Total	2,876,000	2,543,000	2,813,000	2,471,000

(1) We have included in Other major intrastates the volumes of our Gloria system for the three and six month periods ended June 30, 2007 and 2006, in the amounts of 63,000 MMBtu/d, 64,000 MMBtu/d, 64,000 MMBtu/d and 63,000 MMBtu/d, respectively.

Three months ended June 30, 2007 compared with three months ended June 30, 2006

Our Natural Gas segment contributed $39.2 million of operating income for the three months ended June 30, 2007, an increase of $0.5 million from the $38.7 million contributed in the corresponding period of 2006. Our revenues improved over the same period last year primarily due to greater volumes gathered and processed in connection with additional capacity from projects coming on-line during the quarter and increased drilling activity in the areas served by our natural gas assets.

Average daily volumes on our major natural gas systems increased approximately 13 percent in the second quarter of 2007, compared with the corresponding period in 2006. The increased volumes for 2007 continue to reflect our ongoing investments to further expand the capacity of our systems and services. The following projects completed during 2006 and 2007 contributed to the increase in the average daily volumes and operating results on our major natural gas systems:

- Completion of Phase I of our East Texas Expansion and Extension project (Project Clarity) which includes the Marquez treating plant with additional capacity of 200 million cubic feet per day, or MMcf/d, of natural gas and additional pipeline capacity to the existing southeast section of this area;

- Expansion of our existing 275 MMcf/d Aker treating facility with construction of a pipeline adjoined to our Marquez treating plant to increase our treating capacity;
- Construction of our Hidetown processing facility on our Anadarko system was commissioned at the end of April 2007 and was operating at expected levels by the end of May 2007, with capacity of 120 MMcf/d;
- Construction of our 120 MMcf/d Henderson natural gas processing facility on our East Texas system was completed at the end of the third quarter of 2006 and processed incremental volumes of approximately 116 MMcf/d; and
- A link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005;

In addition to the investments we have made to expand the volumes in areas served by our natural gas assets, the volume and revenue growth is also the result of additional wellhead supply contracts and robust drilling activity in the Anadarko basin, Bossier Trend and Barnett Shale. We expect increasing volumes on our major natural gas systems to result from our continuing investments to expand the capacity of our systems.

Although the average daily volumes of our natural gas systems for the three months ended June 30, 2007 were greater than same period of 2006, operating income of our Natural Gas business was negatively affected by lower processing revenue less the cost of natural gas purchased for processing, which we refer to as processing margin. A variable element of our Natural Gas segment's operating income is derived from processing of natural gas under keep-whole arrangements. Operating income derived from our keep-whole processing for the three months ended June 30, 2007 decreased to approximately $13.5 million from $17.4 million for the same period in 2006. Circumstances in the second quarter of 2006, resulting from instability in the crude oil market created an operating environment where NGL prices, which tend to move in correlation with crude oil prices, were trending higher while natural gas prices were declining. As a result, although processing margins in the second quarter of 2007 were favorable, they were not as favorable as in the same period of 2006.

Our processing margin was also reduced by approximately $2.5 million in the second quarter of 2007 due to the carryover effect of operational problems we identified with our Zybach processing facility in the first quarter of 2007. In April 2007, we undertook a project to repair and modify our Zybach processing plant to increase its NGL recoveries, which had decreased in the first quarter of 2007 compared to the level of production when we initially commissioned the plant in 2006. We completed the necessary repairs and modifications during April 2007 and the plant recovered NGLs at expected levels throughout May and June of 2007.

A portion of our Natural Gas segment is exposed to commodity price risks associated with the percentage of proceeds, percentage of liquids, and percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. We target approximately 70 to 80 percent hedge coverage of our anticipated near-term exposure to commodity prices using derivative financial instruments. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will pay for natural gas and receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time. Another significant portion of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services which are not directly dependent on commodity prices.

Operating income of our Natural Gas segment for the three months ended June 30, 2007 includes unrealized non-cash, mark-to-market net losses of $2.6 million, including $0.2 million of gains resulting from ineffectiveness of our cash flow hedges and $2.8 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. In the three months ended June 30, 2006, our operating income was decreased by unrealized non-cash, mark-to-market net losses of $3.7 million, including $0.1 million of losses resulting from ineffectiveness of our cash flow hedges and $3.6 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled (refer also to the discussions included in Note 10 of Item 1. Financial Statements and following under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Operating and administrative costs of our Natural Gas segment were $10.9 million greater for the three months ended June 30, 2007 than the three months ended June 30, 2006, primarily as a result of $6.1 million in increased workforce related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. In addition, repairs and maintenance costs increased by $1.9 million, including costs related to compressor maintenance, downtime for routine and unscheduled maintenance, $0.6 million of pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. Included in the costs related to repairs and maintenance is $0.6 million of operating expenses associated with modifications made to correct the operating inefficiencies associated with our Zybach processing facility.

Workforce related costs increased $6.1 million due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations. 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 continuous pipeline expansions across the areas we serve. We expect workforce related costs in addition to materials, supplies and other cost to continue increasing as we expand our systems and increase the volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was $4.5 million higher in the second quarter of 2007 as compared to the second quarter of 2006, primarily as a result of capital projects completed and placed in-service during 2006. Additionally, we revised the depreciation rates for a portion of our FERC—regulated natural gas assets effective July 1, 2006, to reflect a decrease in the remaining service life of these natural gas assets. We expect depreciation expense to increase throughout 2007 as we complete our construction projects and place the assets into service.

Six months ended June 30, 2007 compared with six months ended June 30, 2006

Our Natural Gas segment produced $50.2 million of operating income for the six months ended June 30, 2007, a decrease of $25.7 million from the $75.9 million of operating income generated in the corresponding period of 2006. Although the overall volumes for the first six months of 2007 on our three largest systems were greater than the comparable period of 2006, operational inefficiencies at our Zybach plant and an unexpected increase in measurement losses, primarily on our East Texas and Anadarko systems reduced the operating income of our Natural Gas segment.

Average daily volumes on our major natural gas systems increased 14 percent, or approximately 342,000 MMBtu/d, for the six months ended June 30, 2007, compared with the corresponding period of 2006, which contributed favorably to our operating income. The contribution to operating income resulting from the increase in average daily volumes was partially offset by the lower processing margins we derived from our processing assets during the six months ended June 30, 2007 in relation to the same period of 2006. Operating income derived from processing natural gas under keep-whole arrangements on our major systems decreased to approximately $19.0 million for the six months ended June 30, 2007, compared with approximately $28 million for the corresponding period in 2006. Additionally, the operational issues associated with our Zybach processing plant reduced our processing margins by approximately $10.5 million from the amounts we realized in the comparable period of 2006. The reasons for the changes in operating income are consistent with the discussion above in our three month analysis, with the exception of measurement losses which are discussed below.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather temperatures and variances in measurement that are inherent in metering technologies. During the first quarter 2007, we identified operating conditions on our gathering systems which we believe have contributed to an increase in measurement losses. We have taken steps to install separator equipment to identify and eliminate free-water in the natural gas streams, one of the underlying causes for the increase in measurement losses during the first quarter of 2007. During the first six months of 2007, we estimate that measurement losses resulted in approximately $11 million of additional cost to our natural gas systems relative to the first six months of 2006.

Operating income of our Natural Gas segment for the six months ended June 30, 2007 includes non-cash, mark-to-market net losses of $5.7 million, including $0.3 million of gains due to hedge ineffectiveness and $6.0 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. In the six months ended June 30, 2006, our operating income was reduced by unrealized non-cash, mark-to-market net losses of $1.9 million, including $0.1 million of losses resulting from ineffectiveness of our cash flow hedges and $1.8 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The non-cash mark-to-market net losses in 2007 are primarily derived from hedge ineffectiveness partially offset by gains from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 as discussed above under our three-month analysis (refer also to the discussions included in Note 10 of Item 1. Financial Statements, below under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Operating and administrative costs associated with our Natural Gas segment were $28.5 million greater for the six months ended June 30, 2007, than for the corresponding period in 2006 for the same reasons discussed above in our three-month analysis.

Future Prospects Update for Natural Gas

We continue to assess various expansion opportunities to pursue our strategy for growth. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. We may, and have, pursued 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 first half of 2007, increased drilling in the areas where our gathering systems are located has contributed to the growth of volumes on our systems. We expect the growth trend in these areas to continue in the future as evidenced by external production forecasts and the strong rig counts and permitting in the areas served by our systems.

Producer drilling plans in regional plays, in the areas served by our natural gas assets, are expected to result in continued production growth. To accommodate this further growth, we initiated construction on several projects to increase our gathering and treating infrastructure and market access capability. These projects continue to progress and include:

East Texas System Expansion and Extension (Project Clarity):

- The expansion and extension of our East Texas natural gas system, referred to as the Clarity project, includes construction of a 36-inch diameter intrastate pipeline from Bethel, Texas to Orange County, Texas with capacity of approximately 700 MMcf/d. The new pipeline will provide service to a number of major industrial companies in Southeast Texas and will cross a number of interstate pipelines. We continue to secure additional commitments for capacity on the pipeline. We have continued to experience cost pressures for labor, materials and rights-of-way, in addition to cost associated with construction delays due to inclement weather. Each of these factors have contributed to our expectation that the ultimate cost to complete construction of this project will approximate $635 million.
- The first phase of our Clarity project was completed in late March 2007 and includes the construction of a 24-inch diameter intrastate pipeline that extends approximately 60 miles from Marquez, Texas to Crockett, Texas and a 36-inch diameter pipeline that extends approximately 53 miles from Crockett to Goodrich, Texas. Completion of this phase has contributed modest operating revenue to our natural gas segment for the second quarter of 2007 following completion of upstream gathering facilities late second quarter.
- The remainder of our Clarity project is expected to be completed in stages throughout 2007 and early 2008. These phases include the construction of a 36-inch diameter intrastate pipeline that extends approximately 63 miles from Bethel to Crockett and approximately 42 miles from Goodrich to Kountze, Texas and approximately 41 miles from Kountze to Orange County.
- As part of our East Texas expansion project we added a 200 MMcf/d treating facility near Marquez which is connected to the 36-inch diameter intrastate pipeline via a new 24-inch diameter pipeline. This project was completed in conjunction with the first phase of our Clarity project in late March 2007 as mentioned above in our operating results, and is expected to contribute additional capacity and volume growth on our East Texas natural gas system through increased carbon dioxide (CO_2) and sour gas treating capacity commensurate with the completion of several ongoing construction projects in the area.

Other East Texas Projects:

- The expansion of our sour gas treating capacity on the East Texas system will increase the total sulfur capacity in the first half of 2007 from 72.5 tons per day (tpd) to 125 tpd by early 2008, in order to handle additional sour gas supply and higher concentration levels of hydrogen sulfide (H_2S).
- The installation of additional processing plants will enable our East Texas system to meet the increasingly more stringent pipeline gas quality specifications by late 2007.

North Texas System Projects:

- In order to accommodate the active development and anticipated growth occurring in the Barnett Shale play in North Texas we have commenced construction of two new gas processing plants totaling approximately 75 MMcf/d of capacity and related upstream facilities. These facilities, with processing capacities of 35 MMcf/d and 40 MMcf/d, are expected to become operational in the second half of 2007.

Anadarko System Projects:

- Our Anadarko system continues to experience considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. We commissioned our Hidetown and Hobart processing plants during the second quarter of 2007, increasing our processing capacity to 170 MMcf/d. Additionally, we continue to increase our field compression in the region. We anticipate these facilities will contribute to our operating results in the second half of 2007.
- During the second quarter of 2007, we refurbished our Zybach processing plant to address the operational inefficiencies being experienced by the plant. As a result of the service and repairs, processing volumes have been restored to expected levels.

When fully operational in late 2007, we expect that the new assets we are constructing will provide additional sources of cash flow for us. We continue to evaluate other projects that could further integrate our major Texas-centered natural gas pipeline systems.

A number of new interstate natural gas transportation pipelines are being constructed that may alter the landscape for interstate transportation of natural gas. Although a majority of our Natural Gas segment revenues are derived from the gathering, processing and intrastate transportation of natural gas, these newly constructed pipelines could affect the operating results of our existing market-based interstate and intrastate natural gas pipelines. Conversely, our supply based gathering systems may benefit from enhanced capacity out of our gathering areas.

Other Matters

In December 2005, Calpine Corporation ("Calpine") and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Calpine has continued to perform under the terms of its agreement with Bamagas. In June 2007, Calpine and certain of its subsidiaries filed a Joint Plan of Reorganization and Disclosure Statement (the "Plan") with the United States Bankruptcy Court. The Plan seeks to provide an equitable return to all stakeholders while providing for the long-term viability of Calpine. The Plan has not been approved by the United States Bankruptcy Court and is subject to further negotiations with stakeholders. The hearing date has not yet been set by the United States Bankruptcy Court for voting purposes. Following the voting process, Calpine will ask the United States Bankruptcy Court to consider approval or "confirmation" of the Plan. Calpine looks to have the Plan confirmed during the fourth quarter of 2007. We remain confident that any losses we may incur with respect to Calpine's bankruptcy will be minimal. We continue to monitor the Calpine bankruptcy proceedings and will recognize any losses that may result when it becomes evident that a loss has been incurred.

Marketing

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

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	(unaudited; in millions)			
Operating revenues	$895.0	$626.3	$1,719.4	$1,521.3
Cost of natural gas	883.8	618.7	1,704.9	1,492.9
Operating and administrative	1.9	1.5	3.5	2.6
Depreciation and amortization	0.7	0.1	0.8	0.2
Expenses	886.4	620.3	1,709.2	1,495.7
Operating Income (loss)	$ 8.6	$ 6.0	$ 10.2	$ 25.6

Three months ended June 30, 2007 compared with three months ended June 30, 2006

In the three months ended June 30, 2007, operating income from our Marketing segment increased $2.6 million to $8.6 million, from $6.0 million for the corresponding period in 2006. Included in operating income for the three months ended June 30, 2007 are unrealized, non-cash, mark-to-market gains of approximately $6.3 million compared with unrealized, non-cash, mark-to-market gains of $5.4 million for the comparable period in 2006, associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The unrealized, non-cash, mark-to-market gains for the three months ended June 30, 2007, are the result of decreases in the forward and daily market prices of natural gas and NGLs from March 31, 2007. We expect these net mark-to-market gains to be offset when the related physical transactions are settled (refer also to the discussion included in Note 10 of Item 1. Financial Statements, following under Derivative Activities and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Partially offsetting the mark-to-market gains is a non-cash charge of $1.2 million we recorded to reduce the cost basis of our natural gas inventory to fair market value at June 30, 2007. Natural gas prices as published by Platt's *Gas Daily* for Henry Hub were approximately $6.80 per MMBtu at June 30, 2007, a decline from $7.34 per MMBtu at March 31, 2007. As a result of this decline in the price of natural gas inventory at our storage locations from March 31, 2007 to June 30, 2007, the weighted average cost of our natural gas inventory at June 30, 2007 exceeded the market price of natural gas by approximately $1.2 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. We incurred a similar non-cash charge totaling $1.7 million for the three months ended June 30, 2006.

Six months ended June 30, 2007 compared with six months ended June 30, 2006

In the first six months of 2007, the operating income of our Marketing segment decreased $15.4 million to $10.2 million, from $25.6 million for the corresponding period in 2006. Included in operating income for the first six months of 2007 are unrealized, non-cash, mark-to-market net losses of approximately $6.9 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with unrealized mark-to-market net gains of $31.3 million for the comparable period in 2006. We expect these net mark-to-market losses to be offset when the related physical transactions are settled (refer also to the discussion included in Note 10 of Item 1. Financial Statements, following under Derivative Activities and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

The operating results of our Marketing business for the first six months of 2007 also include gains of approximately $12 million that we realized upon the sale of natural gas inventory, including approximately $6 million of gains from the settlement of derivative financial instrument hedging our natural gas inventory. Partially offsetting these gains for the six months ended June 30, 2007, are non-cash charges of $1.2 million that we recorded to reduce the cost basis of our natural gas inventory to fair market value. We recorded a similar non-cash charge of $9.7 million during the six months ended June 30, 2006. The market price for natural gas in various storage locations may experience declines during the year from the prices at which the inventory was purchased. 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.

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. A majority of the natural gas we purchase is produced in Texas markets where we have limited physical access to the primary interstate pipeline delivery points, or hubs such as Waha, Texas and the Houston Ship Channel. As a result, our Marketing business must use third-party pipelines to transport the natural gas to these markets where it can be sold to our customers. However, physical pipeline constraints often require our Marketing business to transport natural gas to alternate market points. Under these circumstances, our Marketing segment will sell the purchased gas at a pricing index that is different from the pricing index at which the gas was purchased. This creates a price exposure that arises from the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold, otherwise known as the "spread." The spread can vary significantly due to local supply and demand factors. Wherever possible, this pricing exposure is economically hedged using derivative financial instruments. However, the structure of these economic hedges often precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

To ensure that we have access to primary pipeline delivery points, we often enter into firm transportation agreements on interstate and intrastate pipelines. To offset the demand charges associated with these firm transportation contracts, we look for market conditions that allow us to lock in the price differential or spread between the pipeline receipt point and pipeline delivery point. This allows our Marketing business to lock in a fixed sales margin inclusive of pipeline demand charges. We accomplish this by transacting basis swaps between the index where the natural gas is purchased and the index where the natural gas is sold. By transacting a basis swap between those two indices, we can effectively lock in a margin on the combined natural gas purchase and the natural gas sale, mitigating the demand charges on firm transportation agreements and limiting our exposure to cash flow volatility that could arise in markets where the firm transportation becomes uneconomic. However, the structure of these transactions precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

In addition to natural gas basis swaps, we contract for storage to assist with balancing natural gas supply and end use market sales. In order to mitigate the absolute price differential between the cost of injected natural gas and withdrawn natural gas, as well as storage fees, the injection and withdrawal price differential, or "spread," is hedged by buying fixed price swaps for the forecasted injection periods and selling fixed price swaps for the forecasted withdrawal periods. When the injection and withdrawal spread increases or decreases in value as a result of market price movements, we can earn additional profit through the optimization of those hedges in both the forward and daily markets. Although each of these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact the income statement.

Corporate

Interest expense was $21.5 million and $46.8 million for the three and six month periods ended June 30, 2007, compared with $27.6 million and $55.5 million for the corresponding periods in 2006. The decrease is primarily the result of $10.4 million and $18.9 million of interest capitalized on our construction projects for the three and six month periods ended June 30, 2007, compared with the $3.0 million and $3.4 million capitalized during the same periods of 2006. Partially offsetting the increase in capitalized interest is the additional interest expense generated by higher weighted average debt balances. Our weighted average rates of interest were approximately 5.96% and 5.92% during the three and six month periods ended June 30, 2007, respectively, compared with approximately 5.86% and 5.87% during the corresponding periods in 2006.

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Our income tax expense of $1.3 million and $2.4 million for the three and six month periods ended June 30, 2007 results from the enactment, by the State of Texas, of a new state tax computed on our 2007 modified gross margin. No comparable tax existed during 2006. We determined this tax to be an income tax under the provisions of SFAS No. 109, *Accounting for Income Taxes*. We computed our income tax expense for the quarter ended June 30, 2007 by applying a 0.56% apportioned state income tax rate to taxable margin, as defined in State of Texas statutes. Our income tax expense represents a 2.2% effective rate as applied to pretax book income.

In July 2007, the State of Michigan enacted substantial changes to its tax structure effective in 2008 by imposing a new tax system on our operations. The new system is comprised of two parts, a modified gross receipts tax at 0.8% and a 4.95% tax on income that will be levied on our Michigan operating activities. We expect to account for the impact of the income tax under SFAS No. 109, Accounting for Income Taxes in the third quarter of 2007. We anticipate the effect of this tax legislation will be to increase our income tax expense for 2007 by approximately $1.0 million.

LIQUIDITY AND CAPITAL RESOURCES

General

We believe that our ability to generate cash flow, in addition to our access to capital, is sufficient to meet the demands of our current and future operating and investment needs. Our primary cash requirements consist of normal operating expenses, capital expenditures for our expansion projects, maintenance capital expenditures, debt service payments, distributions to our partners, acquisitions of new assets and businesses, and payments associated with our derivative transactions. Short-term cash requirements, such as operating expenses, maintenance capital expenditures debt service payments and quarterly distributions to our partners, are expected to be funded by our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from our operating activities, borrowings under our commercial paper program or Credit Facility, and the issuance of additional debt and equity securities. Our ability to complete future offerings of our debt and equity securities and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. The internal growth projects we have planned for our Natural Gas business (see Natural Gas segment—Future Prospects), coupled with the Southern Access and Alberta Clipper projects on our Lakehead system (see Liquids segment—Future Prospects), will require significant expenditures of capital over the next several years. We expect to fund these expenditures from a balanced combination of additional issuances of equity, in the form of limited partnership interests, and long-term debt. Our planned internal growth projects will require us to bear the cost of constructing these assets before we will begin to realize a return on them in the form of additional cash flows. During our construction of these major projects, our ability to increase distributions while funding these construction costs is likely to be limited.

Capital Resources

Equity Capital

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity markets to obtain the capital necessary to fund these projects. During the first half of 2007, we generated $628.8 million of cash through equity issuances in both public and private transactions, including contributions of approximately $12.5 million from our general partner to maintain its two percent general partner interest. We used the proceeds from these offerings partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion projects, and invested the remaining amount in short-term commercial paper for use in future periods to fund additional expenditures under our capital expansion programs.

The following table provides additional information about these offerings:

Issuance Date	Class of Limited Partnership Interest	Number of Units Issued	Offering Price per Unit	Net Proceeds to the Partnership	General Partner Contribution	Net Proceeds Including General Partner Contribution
			(in millions, except per unit amounts)			
May 2007	Class A	5.300	$58.00	$301.9	$ 6.1	$308.0
April 2007	Class C	5.931	$53.11	314.4	6.4	320.8
Total		11.231		$616.3	$12.5	$628.8

Available Credit

A significant source of our liquidity is 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 are generally lower than the rates available under our Credit Facility.

Credit Facility

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. At June 30, 2007, no amounts had been borrowed against our Credit Facility and we had approximately $90.0 million of letters of credit outstanding. At June 30, 2007, we could borrow $765.0 million under the terms of our Credit Facility without consideration to additional borrowings under our commercial paper program.

On April 4, 2007 we entered into the Second Amended and Restated Credit Agreement (Credit Facility) which among other things: (i) increases the maximum principal amount of credit available at any one time to us from $1 billion to $1.25 billion; (ii) gives us the right to request increases in the maximum principal amount of credit available at any one time to us up to $1.5 billion; (iii) eliminates the sublimit on letters of credit; (iv) provides for a five-year facility that matures April 4, 2012 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity; (v) modifies our leverage ratio to include in the calculations of EBITDA (as defined in the Second Amended and Restated Credit Agreement) pro forma adjustments for material projects and to exclude from the calculation of Consolidated Funded Debt (as defined in the Second Amended and Restated Credit Agreement) certain amounts of preferred securities and subordinated debt that we or our designated subsidiaries may issue in the future; and (vi) eliminates our coverage ratio financial covenant. Our Credit Facility continues to support our commercial paper program.

Commercial Paper

Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. At June 30, 2007, we had outstanding $393.3 million of commercial paper, net of unamortized discount of $1.7 million, bearing interest at a weighted average rate of 5.48%. At December 31, 2006, we had $443.7 million of commercial paper outstanding, net of $1.3 million of unamortized discount, at a weighted average interest rate of 5.45%. At June 30, 2007, we could issue an additional $205 million in principal amount under our commercial paper program.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. In 2007, we expect to spend approximately $2.1 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. As of June 30, 2007, we have approximately $620 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 2007. However, we will incur additional commitments as our capital projects continue to progress.

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, 2007. 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 $891.5 million, including $26.4 million on core maintenance activities, during the six months ended June 30, 2007.

For the full year of 2007, we anticipate our capital expenditures to approximate the following in millions:

System enhancements	$ 570
Core maintenance activities	60
Southern Access expansion	1,050
Alberta Clipper	120
East Texas expansion	300
	$2,100

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our estimated construction cost, actual expenditures through June 30, 2007, the incremental capacity that will become available upon completion of the project and the periods during which we expect to complete the construction. From project inception, through the first six months of 2007, we have incurred approximately $1.5 billion of capital expenditures associated with the projects listed below. The estimated 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 Total Cost	Actual Expenditures Inception through June 30, 2007	Storage	Oil	Natural Gas	Expected Completion
	(in billions)		(KBbl)	(Kbpd)	(MMcf/d)	
Southern Access expansion (Lakehead)	$1.8	$0.53	—	400	—	2009
Clarity (East Texas)	0.6	0.51	—	—	700	In phases to early 2008
Alberta Clipper	1.0	—	—	450	—	Mid-2010
North Dakota system expansion	0.1	0.03	—	30	—	Late 2007
Cushing terminal storage tanks	0.1	0.06	4,970	—	—	Throughout 2007
Griffith and Superior storage tanks	0.1	0.02	1,220	—	—	Mid-2007 and Mid-2008
Natural gas connects and compression	0.1	0.11	—	—	—	Various
Processing and treating plant expansions	0.3	0.23	—	—	1,130	Various
Total	$4.1	$1.49	6,190	880	1,830	

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our East Texas expansion and extension, 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 and 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 financial 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 financial 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 financial instruments at June 30, 2007 for each of the indicated calendar years:

	Notional	2007	2008	2009	2010	2011	2012
			($ in millions)				
Swaps							
Natural gas[1]	257,949,129	$(17.3)	$(37.7)	$(34.6)	$(29.5)	$(26.0)	$(5.1)
NGL[2]	7,808,300	(25.1)	(20.8)	(10.8)	(5.2)	(1.6)	—
Crude[2]	1,187,779	(5.5)	(8.7)	(3.1)	(1.6)	(1.0)	—
Options—calls							
Natural gas[1]	1,645,000	(0.6)	(1.4)	(1.4)	(1.3)	(1.1)	—
Options—puts							
Natural gas[1]	2,135,000	0.3	—	—	—	—	—
Totals		$(48.2)	$(68.6)	$(49.9)	$(37.6)	$(29.7)	$(5.1)

(1) Notional amounts for natural gas are recorded in MMBtu.
(2) Notional amounts for NGL and Crude are recorded in Bbl.

Operating Activities

Net cash provided by operating activities for the six months ended June 30, 2007 was $258.7 million, an increase of $91.7 million from the $167.0 million generated during the same period in 2006. The improved operating cash flow is primarily attributable to sales of inventory in the first half of 2007 that we did not make in the first half of 2006, and other changes in working capital accounts. Additional, net cash provided by operating activities increased due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

Net cash used in our investing activities during the six months ended June 30, 2007 was $805.4 million, an increase of $491.9 million from the $313.5 million used during the same period of 2006. The increase is primarily attributable to the $606.3 million increase in our investments in property, plant and equipment during the first six months of 2007, over the amount spent during the same period of 2006, partially offset by an $82.4 million increase in our construction payables and no acquisitions in 2007. The increase in our capital expenditures during the first six months of 2007 is directly attributable to our previously announced expansion projects.

Financing Activities

Net cash provided by financing activities during the six months ended June 30, 2007 was $466.5 million, an increase of $320.6 million from the $145.9 million generated during the same period in 2006. The increase in cash flow from financing activities is primarily attributable to our unit issuances, which are partially offset by net repayments of commercial paper. During the first six months of 2007 we issued a total of 11.2 million Class A and C units for net proceeds of approximately $628.8 million and made $46.5 million in net repayments of commercial paper, which include gross issuances of $2,495.7 million and gross repayments of $2,542.2 million.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On July 27, 2007, the Board of Directors of Enbridge Management declared a distribution payable to our partners on August 14, 2007. The distribution will be paid to unitholders of record as of August 6, 2007, of our available cash of $92.6 million at June 30, 2007, or $0.925 per common unit. Of this distribution, $63.7 million will be paid in cash, $12.1 million will be distributed in i-units to our i-unitholder, $16.2 million will be distributed in Class C units to the holders of our Class C units and $0.6 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, 2007, we increased our rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In March 2006, The FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, not the SEP II, Terrace and Facilities surcharges. Effective July 2007, we increased the transportation rates on our Lakehead system by an average of 4.5 percent. Our Lakehead system base tariff rates are slightly below the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new rate for heavy crude movements from the International Border near Neche, North Dakota to Chicago, Illinois is $0.958 per barrel, which reflects a $0.032 per barrel increase over the rates filed effective April 1, 2007. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems by an average of 4.3 percent. The tariff rates for our North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

Effective April 1, 2007, we filed our annual tariff with the FERC for our Lakehead system to reflect the annual calculation of the SEP II and other surcharges based on true-ups of prior year amounts and estimates for 2007, as well as an adjustment for the Terrace surcharge due to lower than expected volumes moving on the Lakehead system in 2006. These surcharges compensate Lakehead for expansions of the system completed in prior years. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago by approximately $0.007 per barrel, to approximately $0.926 per barrel.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities.* This statement provides companies with an option to report certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to reduce the volatility in earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007, as we have elected not to early adopt the provisions of SFAS No. 159. We do not expect our adoption of SFAS No. 159 to have a material effect on our Consolidated Financial Statements.

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, 2006, 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 financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial 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 provide information about our derivative financial instruments at June 30, 2007 and December 31, 2006, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At June 30, 2007						At December 31, 2006	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2007								
Swaps								
Receive variable/pay fixed....	Natural gas	25,880,780	$ 6.77	$ 7.45	$ 5.1	$(22.3)	$ 8.1	$(86.7)
	NGL	50,232	47.51	43.65	0.2	—	—	(0.5)
Receive fixed/pay variable....	Natural gas	27,874,594	7.03	7.05	18.4	(18.8)	79.8	(33.0)
	NGL	2,193,464	38.16	49.89	—	(25.3)	14.4	(23.2)
	Crude oil	189,888	41.71	71.23	—	(5.5)	—	(8.6)
Receive variable/pay variable .	Natural gas	53,443,656	6.84	6.84	2.7	(2.4)	3.1	(3.7)
Options								
Calls (written)..............	Natural gas	184,000	7.33	4.31	—	(0.6)	—	(1.0)
Puts	Natural gas	674,000	7.14	6.15	0.3	—	1.0	—

	At June 30, 2007						At December 31, 2006	
			Wtd Avg Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed....	Natural gas	20,975,750	7.88	7.48	12.3	(4.1)	9.5	(5.1)
Receive fixed/pay variable....	Natural gas	25,386,896	6.37	8.36	2.0	(50.1)	3.6	(44.1)
	NGL	2,603,724	39.78	48.21	—	(20.8)	2.5	(7.7)
	Crude oil	337,241	45.16	72.35	—	(8.7)	—	(7.0)
Receive variable/pay variable .	Natural gas	32,714,803	8.35	8.28	3.2	(1.0)	2.5	(0.4)
Options								
Calls (written).............	Natural gas	366,000	8.40	4.31	—	(1.4)	—	(1.3)
Puts	Natural gas	366,000	8.40	3.40	—	—	—	—
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed....	Natural gas	6,846,254	8.13	7.40	5.2	(0.6)	2.9	(2.1)
Receive fixed/pay variable....	Natural gas	12,985,240	5.18	8.57	0.2	(39.9)	0.7	(31.5)
	NGL	1,927,565	42.43	48.67	—	(10.8)	1.4	(1.4)
	Crude oil	264,625	59.09	72.38	—	(3.1)	—	(1.9)
Receive variable/pay variable .	Natural gas	20,622,611	8.78	8.75	1.4	(0.9)	1.4	(0.6)
Options								
Calls (written).............	Natural gas	365,000	8.55	4.31	—	(1.4)	—	(1.2)
Puts	Natural gas	365,000	8.55	3.40	—	—	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed....	Natural gas	2,228,045	8.11	6.10	3.8	—	2.5	(0.3)
Receive fixed/pay variable....	Natural gas	9,670,000	4.19	8.31	—	(34.0)	0.2	(26.1)
	NGL	784,750	33.94	41.69	—	(5.2)	—	(1.5)
	Crude oil	213,525	63.00	71.79	—	(1.6)	—	(0.6)
Receive variable/pay variable .	Natural gas	9,000,000	9.09	9.00	1.0	(0.3)	0.8	(0.1)
Options								
Calls (written).............	Natural gas	365,000	8.36	4.31	—	(1.3)	—	(1.0)
Puts	Natural gas	365,000	8.36	3.40	—	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed....	Natural gas	730,000	8.08	3.57	2.6	—	2.0	—
Receive fixed/pay variable....	Natural gas	7,952,500	3.63	8.07	—	(28.6)	—	(21.5)
	NGL	248,565	32.12	40.31	—	(1.6)	—	(0.6)
	Crude oil	182,500	64.30	71.28	—	(1.0)	—	(0.2)
Options								
Calls (written).............	Natural gas	365,000	8.08	4.31	—	(1.1)	—	(0.9)
Puts	Natural gas	365,000	8.08	3.40	—	—	—	—
Contracts maturing after 2011								
Swaps								
Receive variable/pay fixed....	Natural gas	182,000	8.73	3.57	0.7	—	0.6	—
Receive fixed/pay variable....	Natural gas	1,456,000	3.57	8.73	—	(5.8)	—	(4.5)

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

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

(3) The fair value is determined based on quoted market prices at June 30, 2007 and December 31, 2006, 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.

Item 4. Controls and Procedures

The Partnership 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 June 30, 2007. 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. No changes in our internal control over financial reporting were made during the three months ended June 30, 2007 that would materially affect our internal control over financial reporting, nor were any corrective actions with respect to significant deficiencies or material weaknesses necessary subsequent to that date.

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, 2006.

RISKS RELATED TO OUR BUSINESS

Changes in our tariff rates or challenges to our tariff rates could have a material adverse effect on our financial condition and results of operations.

The tariff rates charged by several of our existing pipeline systems are regulated by the FERC, or various state regulatory agencies. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, the profitability of our pipeline businesses might suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which delay could further reduce our cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically propose and implement new rules and regulations, terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the tariff rates charged for our services. Some producing states, including Oklahoma and Texas, are considering legislation that would require rate and/or service regulation of gathering and intrastate transmission natural gas systems. Increased state regulation could adversely impact our natural gas systems.

The question of whether and to what extent an income tax allowance should be included in a regulated utility's cost of service for rate-making purposes has been a matter of uncertainty for a number of years and has been pending judicial review. On May 29, 2007 the United States Court of Appeals for the District of Columbia Circuit (the "DC Circuit") denied petitions for review of the FERC's income tax allowance ("ITA") policy. The DC Circuit, which previously vacated and remanded prior FERC orders on the subject, affirmed the ITA policy that the FERC adopted in its May 4, 2005, Policy Statement on Income Tax Allowances, 111 FERC ¶ 61,139 ("Policy Statement") which concluded that "such an allowance should be permitted on all partnership interests, or similar legal interests, if the owner of that interest has an actual or potential income tax liability on the public utility income earned through the interest," thereby extending the ITA to both corporations and partnerships (or other pass-through entities). The DC Circuit's opinion is not yet final, and is subject to potential requests for rehearing and/or review by the United States Supreme Court. In addition, the FERC's Policy Statement contemplates that individual rate proceedings will determine "whether a particular partner … has an actual or potential income tax liability, and what assumptions, if any, should determine the amount of the related tax rate …"

A related issue is whether the FERC's Policy Statement can be relied upon by shippers as a substantial change in circumstances sufficient to remove the grandfathering protection under the Energy Policy Act of 1992 ("EP Act") from an oil pipeline's rates. As part of its May 29, 2007 opinion, the DC Circuit denied the petitions for review with respect to the EP Act issues and upheld the FERC's interpretation of the EP Act as reasonable. As noted above, the DC Circuit's opinion is not yet final.

We believe that the rates we charge for transportation services on our interstate common carrier liquids pipelines are just and reasonable under the Interstate Commerce Act. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

TAX RISKS TO COMMON UNITHOLDERS

We may be classified as an association taxable as a corporation rather than as a partnership, which would substantially reduce the value of our Class A Common Units.

We could be treated as a corporation for federal income tax purposes. Our treatment as a corporation would substantially reduce the cash distributions on the Class A Common Units that we distribute quarterly. Moreover, treatment of us as a corporation could materially and adversely affect our ability to make payments on our debt securities. The anticipated benefit of an investment in our Class A Common Units depends largely on the treatment of us as a partnership for federal income tax purposes. Under current law, we are treated as a partnership for federal income tax purposes and do not pay any federal income tax at the entity level. In order to qualify for this treatment, we must derive more than 90% of our annual gross income from specified investments and activities. While we believe that we currently do qualify and intend to meet this income requirement, we may not find it possible, regardless of our efforts, to meet this income requirement or may inadvertently fail to meet this income requirement. Current law may change so as to cause us to be treated as a corporation for federal income tax purposes without regard to our sources of income or otherwise subject us to entity-level taxation. If we were to be treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would pay state income taxes at varying rates. Under current law, distributions to unitholders would generally be taxed as a corporate distribution. Because a tax would be imposed upon us as a corporation, the cash available for distribution to a unitholder would be substantially reduced. Treatment of us as a corporation would cause a substantial reduction in the value of our Class A Common Units.

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. State tax legislation resulting in the imposition of a partnership-level income tax on us would reduce the cash distributions on the Class A Common Units and the value of the i-units that we will distribute quarterly to Enbridge Management. The enactment of significant legislation imposing partnership-level income taxes could cause a reduction in the value of our Class A Common Units.

If the Internal Revenue Service does not respect our curative tax allocations, the after-tax return to our unitholders on their investment in our Class A Common Units would be adversely affected.

Our partnership agreement allows curative allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and S-8 book basis of our assets existing at the time of issuance of any Class A Common Units. If the Internal Revenue Service, which we refer to as the IRS, does not respect our curative allocations, ratios of taxable income to cash distributions received by the holders of Class A Common Units will be materially higher than previously estimated.

The tax liability of our unitholders could exceed their distributions or proceeds from sales of Class A Common Units.

The holders of our Class A Common Units will be required to pay federal income tax and, in some cases, state and local income taxes on their allocable share of our income, even if they do not receive cash distributions from us. They will not necessarily receive cash distributions equal to the tax on their allocable share of our taxable income. Further, if we have a large amount of nonrecourse liabilities, they may incur a tax liability that is greater than the money they receive when they sell their Class A Common Units.

A unitholder may be required to file tax returns with and pay income taxes to the states where we or our subsidiaries own property and conduct business.

In some cases, a unitholder may be required to file income tax returns with and pay income taxes to the states in which we or our subsidiaries own property and conduct business, which are currently Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, North Carolina, North Dakota, Oklahoma, South Carolina, Tennessee, Texas and Wisconsin. In the future, we may acquire property or do business in other states or in foreign jurisdictions. In addition to tax liabilities to such state and foreign jurisdictions, the owner of a Class A Common Unit may also incur tax and filing responsibilities to localities within such jurisdictions.

Ownership of Class A Common Units raises issues for tax-exempt entities and other investors.

An investment in our Class A Common Units by tax-exempt entities, including employee benefit plans, individual retirement accounts, Keogh plans and other retirement plans, regulated investment companies and foreign persons raises issues unique to them. Virtually all of the income derived from our Class A Common Units by a tax-exempt entity will be "unrelated business taxable income" and will be taxable to the tax-exempt entity. Further, a unitholder who is a nonresident alien, a foreign corporation or other foreign person will be required to file a federal income tax return and pay tax on his share of our taxable income because he will be regarded as being engaged in a trade or business in the United States as a result of his ownership of a Class A Common Unit.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the Class A Common Units.

When we issue additional Class A Common Units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of Class A Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of Class A Common Units and could have a negative impact on the value of the Class A Common Units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

We treat each purchaser of Class A Common Units as having the same tax benefits without regard to the actual Class A Common Units purchased. The IRS may challenge this treatment, which could result in a unitholder owing more tax and may adversely affect the value of the Class A Common Units.

To maintain the uniformity of the economic and tax characteristics of our Class A Common Units, we have adopted certain depreciation and amortization positions that are inconsistent with existing Treasury regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding Class A Common Units. A subsequent holder of those Class A Common Units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). However, because we cannot identify these Class A Common Units once they are traded by the initial holder, we do not give any subsequent holder of a Class A Common Unit any such amortization deduction. This approach understates deductions available to those unitholders who own those Class A Common Units and results in a reduction in the tax basis of those Class A Common Units by the amount of the deductions that were allowable but were not taken.

The IRS may challenge the manner in which we calculate our unitholder's basis adjustment under Internal Revenue Code Section 743(b). If so, because neither we nor a unitholder can identify the Class A Common Units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all unitholders selling Class A Common Units within the period under audit as if all unitholders owned Class A Common Units with respect to which allowable deductions were not taken. Any position we take that is inconsistent with applicable Treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our unitholders. It also could affect the gain from a unitholder's sale of Class A Common Units and could have a negative impact on the value of the Class A Common Units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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: July 30, 2007

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

Date: July 30, 2007

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.

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).
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).
4.2	Registration Rights Agreement, dated April 2, 2007 by and among Enbridge Energy Partners, L.P. Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K dated April 2, 2007).
10.1	Second Amended and Restated Credit Agreement dated as of April 4, 2007, by and among the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1of the Partnership's Current Report on Form 8-K dated April 10, 2007).
10.2	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on May 17, 2007).
10.3*	Offer of Settlement, dated December 21, 2005, as filed with the Federal Energy Regulatory Commission for approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy, Limited Partnership of the costs for the Southern Access Mainline Expansion and approval of the Offer of Settlement dated March 16, 2006.
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.