UNITED STATES
SECURITIES AND EXCHANGE COMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2006

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, 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 49,938,834 Class A common units outstanding as of October 30, 2006.

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In this report, unless the context requires otherwise, references to "we", "us", "our", or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "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, 2005 and in Part II, Item 1A of our quarterly reports on Form 10-Q.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$1,532.3	$1,809.6	$4,845.6	$4,392.4
Operating expenses				
Cost of natural gas (Notes 5 and 10)	1,265.9	1,659.8	4,099.2	3,882.4
Operating and administrative	95.1	82.4	256.3	237.2
Power	27.8	19.0	78.3	53.2
Depreciation and amortization (Note 6)	34.8	36.5	101.5	103.9
	1,423.6	1,797.7	4,535.3	4,276.7
Operating income	108.7	11.9	310.3	115.7
Interest expense	(28.5)	(28.4)	(84.0)	(79.6)
Other income	2.0	2.1	7.4	3.4
Net income (loss)	$ 82.2	$ (14.4)	$ 233.7	$ 39.5
Net income (loss) allocable to limited partner units (Note 2)	$ 73.5	$ (19.5)	$ 210.6	$ 22.6
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	$ 1.03	$ (0.32)	$ 3.11	$ 0.37
Weighted average units outstanding	71.7	62.1	67.8	61.5

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(unaudited; in millions)			
Net income (loss)	$ 82.2	$ (14.4)	$233.7	$ 39.5
Other comprehensive income (loss) (Note 10)	91.8	(138.4)	95.6	(224.1)
Comprehensive income (loss)	$174.0	$(152.8)	$329.3	$(184.6)

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 233.7	$ 39.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	101.5	103.9
Derivative fair value (gains) losses (Note 10)	(53.1)	69.4
Inventory market price adjustments (Note 5)	16.7	—
Other	5.1	(0.1)
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	(5.3)	(13.1)
Due from General Partner and affiliates	9.2	(6.2)
Accrued receivables	236.8	(338.8)
Inventory (Note 5)	(56.7)	(66.2)
Current and long-term other assets (Note 10)	(3.3)	(3.3)
Due to General Partner and affiliates	2.0	13.5
Accounts payable and other (Notes 4 and 10)	(18.5)	(2.0)
Accrued purchases	(258.5)	385.5
Interest payable	19.0	24.5
Property and other taxes payable	1.3	1.6
Net cash provided by operating activities	229.9	208.2
Cash used in investing activities		
Additions to property, plant and equipment	(514.3)	(261.9)
Changes in construction payables	17.4	3.3
Asset acquisitions, net of cash acquired (Note 3)	(33.3)	(186.4)
Other	0.4	2.7
Net cash used in investing activities	(529.8)	(442.3)
Cash provided by financing activities		
Proceeds from unit issuances, net (Note 8)	509.6	127.5
Distributions to partners (Note 8)	(169.8)	(157.3)
Repayments of Credit Facility, net (Note 7)	—	(175.0)
Net issuances of commercial paper (Note 7)	143.9	455.0
Repayment on affiliate loan	(20.0)	—
Other	—	(1.0)
Net cash provided by financing activities	463.7	249.2
Net increase in cash and cash equivalents	163.8	15.1
Cash and cash equivalents at beginning of year	89.8	78.3
Cash and cash equivalents at end of period	$ 253.6	$ 93.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2006	December 31, 2005
	(unaudited; $ in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 4)	$ 253.6	$ 89.8
Receivables, trade and other, net of allowance for doubtful accounts of $4.0 in 2006 and $4.5 in 2005	114.9	109.7
Due from General Partner and affiliates	10.9	20.1
Accrued receivables	378.5	615.3
Inventory (Note 5)	175.9	138.9
Other current assets (Note 10)	12.7	11.5
	946.5	985.3
Property, plant and equipment, net (Notes 3 and 6)	3,509.6	3,080.0
Other assets, net (Note 10)	24.3	22.2
Goodwill (Note 3)	265.7	258.2
Intangibles, net (Note 3)	92.4	82.7
	$4,838.5	$4,428.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 14.5	$ 12.5
Accounts payable and other (Notes 4 and 10)	183.0	247.9
Accrued purchases	388.2	646.7
Interest payable	28.8	11.4
Property and other taxes payable	22.2	21.8
Current maturities of long-term debt	31.0	31.0
	667.7	971.3
Long-term debt (Note 7)	1,827.4	1,682.9
Loans from General Partner and affiliates	134.0	151.8
Environmental liabilities (Note 9)	4.2	4.8
Other long-term liabilities (Note 10)	172.3	253.8
	2,805.6	3,064.6
Commitments and contingencies (Note 9)		
Partners' capital (Note 8)		
Class A common units (Units issued—49,938,834 in 2006 and 2005)	1,159.9	1,142.4
Class B common units (Units issued—3,912,750 in 2006 and 2005)	68.9	67.2
Class C units (Units issued—10,869,565 in 2006)	503.7	—
i-units (Units issued—12,440,455 in 2006 and 11,704,948 in 2005)	459.3	421.7
General Partner	47.6	34.6
Accumulated other comprehensive loss (Note 10)	(206.5)	(302.1)
	2,032.9	1,363.8
	$4,838.5	$4,428.4

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

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the financial position as of September 30, 2006 and December 31, 2005; the results of operations for the three and nine month periods ended September 30, 2006 and 2005; and cash flows for the nine month periods ended September 30, 2006 and 2005. The results of operations for the three and nine month periods ended September 30, 2006, 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, maintenance activities and the impact of forward natural gas prices on certain derivative financial instruments that are accounted for using mark-to-market accounting. In addition, prior period information presented in these consolidated financial statements includes reclassifications that were made to conform to the current period presentation. These reclassifications have no effect on previously reported net income or partners' capital. The interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

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 September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(in millions, except per unit amounts)			
Net income (loss)	$82.2	$(14.4)	$233.7	$ 39.5
Allocations to the General Partner:				
Net (income) loss allocated to General Partner	(1.7)	0.3	(4.7)	(0.8)
Incentive distributions to General Partner	(7.0)	(5.4)	(18.3)	(16.0)
Historical cost depreciation adjustments	—	—	(0.1)	(0.1)
	(8.7)	(5.1)	(23.1)	(16.9)
Net income (loss) allocable to limited partner units	$73.5	$(19.5)	$210.6	$ 22.6
Weighted average units outstanding	71.7	62.1	67.8	61.5
Net income (loss) per limited partner unit (basic and diluted)	$1.03	$(0.32)	$ 3.11	$ 0.37

3. ACQUISITIONS

In April 2006, we acquired, for $33.3 million in cash, an 80-mile natural gas pipeline that is complementary to our existing East Texas system. This pipeline provides approximately 100 million cubic feet per day, or MMcf/d, of additional transportation capacity and interconnects with approximately 65 central delivery points.

The purchase price and the allocation to assets acquired and liabilities assumed are as follows in millions of dollars:

Purchase Price:	
Cash paid, including transaction costs	$33.3
Allocation of purchase price:	
Property, plant and equipment, including construction in progress	13.0
Intangibles	12.8
Goodwill	7.5
Total	$33.3

4. 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 $34.8 million at September 30, 2006 and $46.5 million at December 31, 2005, are included in Accounts payable and other on our Consolidated Statements of Financial Position.

5. INVENTORY

Inventory is comprised of the following:

	September 30, 2006	December 31, 2005
	(in millions)	
Material and supplies	$ 4.3	$ 8.3
Liquids inventory	16.9	11.1
Natural gas and natural gas liquids inventory	154.7	119.5
	$175.9	$138.9

Our inventory includes charges totaling $16.7 million, of which $7.0 million was recorded in the current quarter, to reduce the cost basis of our natural gas inventory to reflect market value. The lower of cost or market adjustments are included in the Cost of natural gas of our Natural Gas and Marketing segments on our Consolidated Statements of Income.

6. PROPERTY, PLANT AND EQUIPMENT

Based on a third-party study commissioned by management, revised depreciation rates for the Lakehead system were implemented effective January 1, 2006. The annual composite rate, which represents the expected remaining service life of the Lakehead system assets, was reduced from 3.20% to 2.63%. Depreciation expense was approximately $2.8 million and $8.3 million lower for the three and nine months ended September 30, 2006, respectively, as a result of the new depreciation rates.

7. DEBT

Credit Facility

In March 2006, we obtained an increase from $800 million to $1 billion in the aggregate commitment available to us under the terms of our Credit Facility. At September 30, 2006 and December 31, 2005, we had no amounts outstanding under our Credit Facility. We had letters of credit totaling $59.1 million at September 30, 2006, and $149.3 million at December 31, 2005. 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 September 30, 2006, we could borrow an additional $465.9 million under the terms of our Credit Facility.

During the nine months ended September 30, 2005, we net settled borrowings of approximately $565 million on a non-cash basis.

Commercial Paper Program

We can issue up to $600 million in principal amount of commercial paper under the terms of our commercial paper program. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $400 million. At September 30, 2006, we had $473.8 million of commercial paper outstanding, net of unamortized discount of $1.2 million, bearing interest at a weighted average rate of 5.55%. At December 31, 2005, we had $329.3 million of commercial paper outstanding, net of $0.7 million of unamortized discount, at a weighted average interest rate of 4.36%. At September 30, 2006, we could issue an additional $125 million in principal amount under our commercial paper program.

8. PARTNERS' CAPITAL

The following table sets forth our distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management"), during the nine months ended September 30, 2006:

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]	Retained from General Partner[2]	Distribution of Cash
January 30, 2006	February 14, 2006	February 7, 2006	$0.925	$67.6	$10.8	$0.2	$56.6
April 27, 2006	May 15, 2006	May 5, 2006	$0.925	$67.8	$11.0	$0.2	$56.6
July 28, 2006	August 14, 2006	August 4, 2006	$0.925	$68.1	$11.3	$0.2	$56.6

(1) We have issued 735,507 i-units to Enbridge Management, the sole owner of the Partnership's i-units, during 2006 in lieu of cash distributions.

(2) We retain an amount equal to 2% of the i-unit distribution from the General Partner to maintain its 2% general partner interest.

Private Placement of Class C Units

On August 15, 2006, we issued and sold 5.4 million Class C units, representing a new class of limited partner interest, to our general partner and 5.4 million Class C units to an institutional investor for a purchase price of $46.00 per unit in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933. We received proceeds of approximately $500 million, net of expenses associated with the private placement. Additionally, our general partner contributed approximately $10 million to maintain its two percent general partner interest.

Until August 15, 2009, in lieu of cash distributions, the holders of our Class C units will receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we pay to the holders of our Class A and Class B common units, which we collectively refer to as common units. The number of additional Class C units we will issue is determined by dividing the quarterly cash distribution per unit we pay on our common units by the average market price of a Class A common unit as listed on the New York Stock Exchange for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date.

After August 15, 2009, the holders of our Class C units will receive quarterly cash distributions equal to those paid to the holders of our common units. Subject to the approval of holders of our outstanding units in accordance with the then-existing requirements of the principal national securities exchange on which the Class A common units are listed, the Class C units will convert into Class A common units on a one-for-one basis. If our unitholders do not approve the conversion, the holders of our Class C units will receive quarterly cash distributions equal to 115 percent of those paid to the holders of our common units. Prior to conversion, holders of our Class C units will not be entitled to receive any quarterly cash distribution until the holders of our common units have received a quarterly cash distribution of $0.59 per common unit.

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 liquid and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact on the environment of our pipeline operations.

As of September 30, 2006 and December 31, 2005, we have recorded $3.0 million and $4.0 million, respectively, in current liabilities and $4.2 million and $4.8 million, respectively, in long-term liabilities, primarily to address remediation of contaminated sites, materials containing asbestos, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

In April 2006, a natural gas release and fire near a valve site on our MidLa natural gas transmission pipeline in Concordia Parish, Louisiana, resulted in property and equipment damage in the area. We estimate our losses from this incident to approximate $1 million, which we recognized in the second quarter of 2006. We have not revised our estimate subsequent to the second quarter of 2006.

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. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, natural gas liquids (“NGL” or “NGLs”), condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). This market price exposure 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 financial instruments we utilize.

Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas in our Consolidated Statements of Income. 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 ("OCI"), 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 OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI 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. However, we have four primary transaction types where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas in our

Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated financial instrument contract settlement is made.

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

1. **Transportation—**In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, these derivative financial instruments are marked-to-market.

2. **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from when the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index to better match the indices. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical, and ceasing to do so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing. We will

designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we utilize for the derivative financial instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

The following table presents the 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 September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ (1.4)	$ 0.1	$ (1.5)	$ (1.9)
Non-qualified hedges	3.2	(9.6)	1.4	(20.7)
Marketing				
Non-qualified hedges	21.9	(43.1)	53.2	(37.8)
Discontinued hedges	—	—	—	(9.0)
Derivative fair value gains (losses)	$23.7	$(52.6)	$53.1	$(69.4)

We record the change in fair value of our cash flow hedges in OCI until the derivative financial instruments are settled, at which time they are reclassified from OCI to earnings. Also included in OCI are unrecognized losses of approximately $5.6 million associated with cash flow hedges that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three and nine months ended September 30, 2006, we reclassified losses of $24.0 million and $63.7 million, respectively from OCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

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

	September 30, 2006	December 31, 2005
	(in millions)	
Other current assets	$ 5.9	$ 5.8
Other assets, net	5.9	4.2
Accounts payable and other	(64.2)	(129.2)
Other long-term liabilities	(161.3)	(243.0)
	$(213.7)	$(362.2)

The decrease in our obligation associated with derivative activities is primarily due to the decline in current and forward natural gas prices from December 31, 2005 to September 30, 2006. 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 certain financial information about our business segments:

	As of and for the three months ended September 30, 2006				
	Liquids	Natural Gas	Marketing	Corporate	Total
			(in millions)		
Total revenue	$127.2	$1,251.9	$772.4	$ —	$2,151.5
Less: Intersegment revenue	—	565.3	53.9	—	619.2
Operating revenue	127.2	686.6	718.5	—	1,532.3
Cost of natural gas	—	568.0	697.9	—	1,265.9
Operating and administrative	36.0	56.9	1.1	1.1	95.1
Power	27.8	—	—	—	27.8
Depreciation and amortization	16.0	18.7	0.1	—	34.8
Operating income	47.4	43.0	19.4	(1.1)	108.7
Interest expense	—	—	—	(28.5)	(28.5)
Other income	—	—	—	2.0	2.0
Net income	$ 47.4	$ 43.0	$ 19.4	$ (27.6)	$ 82.2
Capital expenditures (excluding acquisitions)	$ 50.8	$ 175.6	$ 0.9	$ 1.8	$ 229.1

	As of and for the three months ended September 30, 2005				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$104.1	$1,267.5	$1,162.6	$ —	$2,534.2
Less: Intersegment revenue	—	669.6	55.0	—	724.6
Operating revenue	104.1	597.9	1,107.6	—	1,809.6
Cost of natural gas	—	513.9	1,145.9	—	1,659.8
Operating and administrative	36.1	44.3	1.4	0.6	82.4
Power	19.0	—	—	—	19.0
Depreciation and amortization	18.3	18.1	0.1	—	36.5
Operating income	30.7	21.6	(39.8)	(0.6)	11.9
Interest expense	—	—	—	(28.4)	(28.4)
Other income	—	—	—	2.1	2.1
Net income (loss)	$ 30.7	$ 21.6	$ (39.8)	$(26.9)	$ (14.4)
Capital expenditures (excluding acquisitions)	$ 17.3	$ 69.2	$ —	$ 0.7	$ 87.2

	As of and for the nine months ended September 30, 2006				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$ 374.7	$4,085.1	$2,406.4	$ —	$6,866.2
Less: Intersegment revenue	—	1,854.0	166.6	—	2,020.6
Operating revenue	374.7	2,231.1	2,239.8	—	4,845.6
Cost of natural gas	—	1,908.4	2,190.8	—	4,099.2
Operating and administrative	99.7	150.6	3.7	2.3	256.3
Power	78.3	—	—	—	78.3
Depreciation and amortization	47.8	53.2	0.3	0.2	101.5
Operating income	148.9	118.9	45.0	(2.5)	310.3
Interest expense	—	—	—	(84.0)	(84.0)
Other income	—	—	—	7.4	7.4
Net income	$ 148.9	$ 118.9	$ 45.0	$ (79.1)	$ 233.7
Total assets	$1,752.4	$2,584.1	$ 264.6	$237.4	$4,838.5
Capital expenditures (excluding acquisitions)	$ 101.6	$ 404.7	$ 1.8	$ 6.2	$ 514.3

	As of and for the nine months ended September 30, 2005				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$ 303.1	$3,180.1	$2,658.5	$ —	$6,141.7
Less: Intersegment revenue	—	1,635.3	114.0	—	1,749.3
Operating revenue	303.1	1,544.8	2,544.5	—	4,392.4
Cost of natural gas	—	1,299.9	2,582.5	—	3,882.4
Operating and administrative	105.5	126.3	3.1	2.3	237.2
Power	53.2	—	—	—	53.2
Depreciation and amortization	53.6	49.9	0.4	—	103.9
Operating income	90.8	68.7	(41.5)	(2.3)	115.7
Interest expense	—	—	—	(79.6)	(79.6)
Other income	—	—	—	3.4	3.4
Net income	$ 90.8	$ 68.7	$ (41.5)	$(78.5)	$ 39.5
Total assets	$1,672.8	$2,239.4	$ 557.4	$ 91.4	$4,561.0
Capital expenditures (excluding acquisitions)	$ 52.0	$ 206.5	$ —	$ 3.4	$ 261.9

12. SUBSEQUENT EVENT

Distribution to Partners

On October 27, 2006, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2006. The distribution will be paid to unitholders of record as of November 6, 2006, of our available cash of $79.6 million at September 30, 2006, or $0.925 per limited partner unit. Of this distribution, $57.6 million will be paid in cash, $11.5 million will be distributed in i-units to our i-unitholder, $10.1 will be distributed in Class C units to the holders of our Class C units and $0.4 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 September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurement. The statement is effective for fiscal years beginning after November 15, 2007, and with limited exceptions is to be applied prospectively as of the beginning of the fiscal year initially adopted. We do not expect our adoption of this pronouncement to materially effect our financial statements. However, adoption of this pronouncement may affect our disclosures regarding derivative financial instruments and indebtedness.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion of financial condition and results of operations of Enbridge Energy Partners, L.P. should be read together with the consolidated financial statements and related notes included in Item 1 of this report. The discussion in this section pertains to our unaudited consolidated statements of financial position, statements of income, and statements of cash flows included in "Item 1. Financial Statements" of this quarterly report on Form 10-Q.

This quarterly report on Form 10-Q should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2005.

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, transmission 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 the Partnership's cash flow, we enter into derivative financial instrument transactions. Certain of these transactions qualify for hedge accounting under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"); 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 nine month periods ended September 30, 2006 and 2005:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(unaudited; in millions)			
Operating Income				
Liquids	$ 47.4	$ 30.7	$148.9	$ 90.8
Natural Gas	43.0	21.6	118.9	68.7
Marketing	19.4	(39.8)	45.0	(41.5)
Corporate, operating and administrative	(1.1)	(0.6)	(2.5)	(2.3)
Total Operating Income	108.7	11.9	310.3	115.7
Interest expense	(28.5)	(28.4)	(84.0)	(79.6)
Other income	2.0	2.1	7.4	3.4
Net Income (loss)	$ 82.2	$(14.4)	$233.7	$ 39.5

Summary Analysis of Operating Results

Liquids

The increase in operating income of our Liquids segment for the three and nine month periods ended September 30, 2006, over the comparable periods in 2005 is attributable to the following primary factors:

- Higher volumes on our Lakehead system following completion of the repair and expansion of a major oil sands plant that was damaged by a fire in early January 2005, partially offset by higher power costs associated with the increased volumes;
- The annual index rate increase effective July 1, 2006, which increased our average tariffs; and
- Longer transportation hauls on our Lakehead system.

Natural Gas

The increase in operating income of our Natural Gas segment for the three and nine month periods ended September 30, 2006, over the comparable periods in 2005 is primarily attributable to the following:

- Higher NGL prices in relation to crude oil and natural gas prices contributed to favorable operating results from our processing assets in addition to the expanded processing capacity on our Anadarko system;
- Growth in average daily volumes on our major natural gas systems stemming from continued strong drilling activity in areas served by our natural gas gathering and processing assets; and
- Improved rates associated with recontracting of supply and additional fees for services we provide our customers.

Marketing

Operating income from our Marketing segment increased for the three and nine months ended September 30, 2006, from operating losses for the comparable periods in 2005 predominantly as a result of two factors:

- Unrealized, non-cash mark-to-market gains for the three and nine months ended September 30, 2006 of $21.9 million and $53.2 million compared with non-cash mark-to-market losses of $43.1 million and $46.8 million for the comparable periods in 2005. The gains resulted from the change in market value of our derivative financial instruments that do not qualify for hedge accounting. Additionally, in the second quarter of 2005, we recognized approximately $9.0 million of losses for the discontinuance of hedge accounting for derivative financial instruments associated with forecasted transactions we determined were not probable of occurring as set forth in the original hedge documentation;
- Partially offsetting the unrealized mark-to-market gains is a non-cash charge of $6.6 million for the three months and $16.3 million for the nine months ended September 30, 2006, resulting from a lower of cost or market accounting adjustment to the cost basis of our natural gas inventory. The market price for natural gas in various storage locations experienced further decreases during the quarter from the prices at which the inventory was purchased. We expect to recover a majority of this charge when the inventory is sold in future quarters, since we have derivative financial instruments that hedge this physical 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, 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.

Consistent with the current year trend of declining prices, on average natural gas prices declined modestly in the quarter ended September 30, 2006 relative to the second quarter of 2006 and are back at levels that existed prior to the 2005 hurricane season. Additionally, NGL and crude oil prices declined in the current quarter reversing a trend of increasing prices that began in early 2006. This declining price environment has produced net, non-cash mark-to-market gains on the derivative financial instruments that do not qualify for hedge accounting associated with our Marketing and Natural Gas businesses.

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 non-cash, mark-to-market gains and losses by segment, associated with our derivative financial instruments for the three and nine month periods ended September 30, 2006 and 2005:

Derivative fair value gains (losses)	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ (1.4)	$ 0.1	$ (1.5)	$ (1.9)
Non-qualified hedges	3.2	(9.6)	1.4	(20.7)
Marketing				
Non-qualified hedges	21.9	(43.1)	53.2	(37.8)
Discontinued hedges	—	—	—	(9.0)
Derivative fair value gains (losses)	$23.7	$(52.6)	$53.1	$(69.4)

In December 2005, we settled natural gas collars representing derivative financial instruments on forecasted sales of 2,000 million British thermal units per day, or MMBtu/d, of natural gas through 2011. The settlement of these collars reduced the amount of non-cash, market-to-market gains reflected above in our Natural Gas segment at September 30, 2006.

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

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

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(unaudited; in millions)			
Operating Results				
Operating revenues	$127.2	$104.1	$374.7	$303.1
Operating and administrative	36.0	36.1	99.7	105.5
Power	27.8	19.0	78.3	53.2
Depreciation and amortization	16.0	18.3	47.8	53.6
Operating expenses	79.8	73.4	225.8	212.3
Operating Income	$ 47.4	$ 30.7	$148.9	$ 90.8
Operating Statistics				
Lakehead system:				
United States[(1)]	1,175	1,007	1,174	1,023
Province of Ontario[(1)]	275	283	306	295
Total deliveries[(1)]	1,450	1,290	1,480	1,318
Barrel miles (billions)	97	82	291	249
Average haul (miles)	725	691	721	691
Mid-Continent system deliveries[(1)]	244	259	247	225
North Dakota system deliveries[(1)]	89	84	90	87
Total Liquids Segment Delivery Volumes[(1)]	1,783	1,633	1,817	1,630

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

Three months ended September 30, 2006 compared with three months ended September 30, 2005

Our Liquids segment accounted for $47.4 million of operating income during the three months ended September 30, 2006, representing a $16.7 million increase over the same period in 2005. The favorable results of our Liquids segment assets reflect continuing growth in our transportation volumes while actively managing the costs of our services. The majority of this increase relates to significantly improved results on our Lakehead system.

Operating revenues of our Liquids segment assets increased $23.1 million to $127.2 million for the third quarter of 2006 compared with $104.1 million earned in the third quarter of 2005. As indicated in the table above, total delivery volumes of our Liquids segment averaged 1.783 million Bpd in the third quarter of 2006, representing a 0.15 million Bpd increase from the 1.633 million Bpd delivered in the third quarter of 2005. This accounted for an increase in operating revenues of approximately $10.2 million. The increases in deliveries on our Liquids systems are primarily derived from increased production of Western Canadian crude oil delivered to our Lakehead system. The increases of deliveries are attributable to the following:

- Suncor, an oil sands producer in Alberta, Canada, experienced a fire at its upgrader site in January 2005, which affected production for the majority of 2005. In late September 2005, Suncor completed repairs and an expansion to its upgrader site. Suncor's production levels have increased since that time.

- Conventional heavy crude oil and bitumen production have increased as existing and new facilities add to capacity. Also, bitumen production was higher during the third quarter of 2006, as the nature of the cyclical steaming process used to extract it from the ground can cause production timing differences during the year.

Contributing to the revenue growth of our Liquids segment are the increases in the average tariffs on all three of our Liquids systems which resulted in higher operating revenue during the third quarter of 2006 of approximately $10.5 million. These tariff increases were mostly the result of the annual index rate increase allowed by the Federal Energy Regulatory Commission (“FERC”) representing the Producers Price Index for Finished Goods plus 1.3 percent (PPIFG + 1.3) effective July 1, 2006, for our base system tariffs. On our Lakehead system, we increased our rates by an average of 3.0 percent, which is less than the amount allowed under the index. On our Lakehead system, new tariffs also went into effect on April 1, 2006 for an adjustment on the Terrace expansion program surcharge due to lower than expected volumes moving on the Lakehead system, and new facilities in service, that were not operating during the third quarter of 2005.

Operating and administrative expenses for the third quarter 2006 and 2005 were approximately $36 million. Lower oil measurement losses, environmental costs and property taxes, partially offset by higher workforce related costs were the predominant causes for there being no significant changes between periods.

Oil measurement gains and losses occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement gains and losses are:

- physical, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation, which results in the pipelines from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil; and
- revaluation, which is a function of crude oil prices, the level of the carrier’s inventory and the inventory positions of customers.

During the fourth quarter of 2005, we identified certain operating conditions on connected third-party systems that were contributing to higher levels of physical losses on our Lakehead system. Improvements to oil measurement processes have resulted in lower physical losses during the third quarter of 2006. We expect these improvements to have a continuing positive impact on our oil measurement losses throughout the year. We estimate that total oil measurement losses for 2006 will be approximately $5 million, compared with $18 million in 2005, assuming crude oil prices remain comparable to 2005 levels. Power costs increased $8.8 million in the third quarter of 2006, compared to the same period in 2005, primarily due to increased volumes on the Lakehead system and, to a lesser extent, increased power rates.

We completed a depreciation study of the Lakehead system in the first quarter of 2006 that resulted in extending the composite remaining service life of the system assets from 23 to 26 years. The effect of this change was a decrease to depreciation expense of approximately $2.8 million for the three months ended September 30, 2006. We expect the impact of the depreciation study to be a reduction of depreciation expense by approximately $11 million for the full year of 2006.

Nine months ended September 30, 2006 compared with nine months ended September 30, 2005

Our Liquids segment accounted for $148.9 million of operating income during the nine months ended September 30, 2006, representing a $58.1 million increase over the same period in 2005. The components comprising our operating income changed during the first nine months of 2006 compared with the first nine months of 2005 primarily for the same reasons as noted above in the three-month analysis.

Future Prospects Update for Liquids

We and Enbridge Inc. ("Enbridge") continue to actively work with our customers to develop transportation options that will allow western Canadian crude oil access to new markets.

Partnership Projects

In conjuction with Enbridge, we announced in 2005 the approval of the 400,000 Bpd Southern Access expansion project, which received endorsement from the Canadian Association of Petroleum Producers ("CAPP"), a trade association that represents a large majority of the Lakehead system's customers. We are undertaking the U.S. portion of the expansion on our Lakehead system with the first stage to add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. The first stage 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.

On March 16, 2006, the Federal Energy Regulatory Commission ("FERC") approved an Offer of Settlement with respect to tariff principles for the Southern Access expansion, which were negotiated with CAPP. In July 2006, we obtained support from shippers and CAPP to increase the diameter of the new pipeline segments of the project from 36 inches, to which the previously negotiated tariff principles apply, up to 42 inches. The incremental capital cost of the larger diameter pipe is currently estimated at approximately $157 million, bringing our total estimated portion of the costs to approximately $1.3 billion. The larger diameter will not provide increased capacity in the near term but does increase the ultimate capacity of the line from 800,000 Bpd to 1,200,000 Bpd with expenditures for additional pumping. This places us in a favorable position to secure future expansion opportunities for our Lakehead system. We will defer any return on the incremental capital until the additional capacity is required by shippers (see discussion of Alberta Clipper project below). In the interim, shippers will absorb all the incremental operating costs of the larger diameter line but will benefit from reduced power costs at higher throughput levels. Fieldwork has commenced on the project and pipe has been ordered to ensure full completion in early 2009.

Based on forecasts of oil sands production growth prepared by Enbridge, as well as forcasts by CAPP, we believe that there will be a need for additional export pipeline capacity out of Western Canada over and above projects which have already received shipper support. Based on this analysis, as well as interest expressed by shippers, we and Enbridge are planning to develop the Alberta Clipper project. This project will involve construction of a 36-inch diameter heavy crude line from Hardisty, Alberta to Superior, Wisconsin in conjunction with additional pumping power applied to the Southern Access 42-inch pipe from Superior to Flanagan. We anticipate that our share of the cost of this project as currently proposed will approximate $750 million, excluding the approximate cost of $157 million to "prebuild" Southern Access to 42 inches as discussed above.

Alberta Clipper was originally planned to be a contract carrier pipeline based on interest expressed by selected shippers in providing throughput commitments in return for assured access to capacity. Based on discussions with a broader group of shippers the preference is for Alberta Clipper to be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes, provided that it can be developed on a timely basis. Depending on the timing of other export capacity projects, Alberta Clipper could be required to be in service between 2009 and 2011. To maintain the option to achieve an in-service date in the fourth quarter of 2009, we and Enbridge will seek to reach agreement with shippers on the project terms in time to permit filing of regulatory applications before the end of 2006.

Work is proceeding on our previously announced North Dakota system expansion. Three critical hydrostatic pressure tests have been successfully completed and the North Dakota Public Service Commission approvals have been obtained for all phases of the project. Additionally, we have filed the applicable toll surcharges with the FERC with no objections received. The expansion 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 $70 million. The expansion is supported by increasing crude oil production from the Williston Basin in Montana and North Dakota and is expected to be completed in the latter half of 2007. We expect our fourth quarter 2006 volumes to average approximately 95,000 Bpd due to the recent completion of the hydrotest program and addition of drag reducing agents at pump stations along the pipeline.

We continue to experience strong interest from customers in securing access to long-term contract storage capacity at our Cushing, Oklahoma terminal. During the second quarter we obtained commitments and initiated construction activities for a further 1.7 million barrels of storage capacity at an expected cost of approximately $35 million. This will bring the total capacity of our terminal to approximately 16.9 million barrels of which approximately 1.5 million are barrels required as operational tankage to support our Mid-Continent liquids pipeline systems, with the balance available for contract storage.

Enbridge and Other Projects

During the first quarter of 2006, Enbridge completed the reversal of its Spearhead Pipeline that now flows from Chicago, Illinois to Cushing, Oklahoma, with a capacity of 125,000 Bpd. In March 2006, the first western Canadian crude oil was delivered through this system into the major oil hub at Cushing. We expect to benefit from the reversal of the Spearhead pipeline as western Canadian crude oil will be carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline.

In April 2006, ExxonMobil announced it had completed the reversal of two of its crude oil pipelines allowing up to 66,000 Bpd of Canadian crude oil to flow from the U.S. Midwest to the U.S. Gulf Coast. The combined reversed pipeline is linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka, Illinois. The Mustang Pipe Line Partners system is 30% owned by an affiliate of Enbridge. ExxonMobil has received firm commitments from Canadian shippers for an average of 50,000 Bpd of capacity on the lines from Patoka, to Nederland, Texas for the next five years. The connection of our Lakehead system with this new market should also support increased throughput on our Lakehead system; however, the reversed ExxonMobil system is also capable of transporting western Canadian crude oil moved via other competing pipelines into the Patoka market.

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 will be undertaken by Enbridge; however, it will benefit us through incremental volumes moving through our Lakehead system to reach this extension. The Southern Access Extension will be integrated with our Lakehead system for tolling purposes on a distance-based rolled-in basis, with no toll impact on our Lakehead system revenue.

During the third quarter, Enbridge completed a successful open season on its Southern Lights diluent pipeline from Chicago, Illinois to Edmonton, Alberta. The Southern Lights pipeline responds to interest from a number of western Canadian producers to increase the availability of diluent in Alberta. Diluent is required to transport the heavy oil and bitumen being produced in increasing volumes from the Alberta oil sands. The project will require approval of the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") for 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. We expect to benefit from increased heavy crude shipments, which will be facilitated by the diluent line. In addition, this project involves a reconfiguration of the Partnership's light crude mainline system which will provide an additional 30,000 to 50,000 Bpd of effective capacity at no cost to us. Once this capacity is utilized it will generate additional transportation revenue for us. This project is expected to be in service during 2009, coinciding with the completion of the Southern Access project.

Shippers have indicated interest to Enbridge in development of additional pipeline capacity to transport Canadian crude oil to the U.S. Gulf Coast, including the potential for a direct line from Alberta to the Gulf Coast. Enbridge is examining a number of alternatives to respond to this interest, including alternatives that would extend off our Lakehead system, utilizing either existing pipelines which could be connected and reversed, or newly constructed extensions. These alternatives would complement our Lakehead system and support its expansion. Enbridge has indicated that a direct line would require a minimum of 400,000 Bpd of throughput commitments to be economic, and could not be in service before 2011. A direct line, if developed by Enbridge or any other party, would compete with our Lakehead system.

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 MMBtu/d for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 686.6	$ 597.9	$ 2,231.1	$ 1,544.8
Cost of natural gas	568.0	513.9	1,908.4	1,299.9
Operating and administrative	56.9	44.3	150.6	126.3
Depreciation and amortization	18.7	18.1	53.2	49.9
Operating expenses	643.6	576.3	2,112.2	1,476.1
Operating Income	$ 43.0	$ 21.6	$ 118.9	$ 68.7
Operating Statistics (MMBtu/d)				
East Texas[1]	1,062,000	904,000	998,000	841,000
Anadarko	588,000	489,000	573,000	473,000
North Texas	302,000	267,000	288,000	264,000
South Texas[1]	—	31,000	—	34,000
UTOS	205,000	154,000	197,000	181,000
MidLa	144,000	129,000	119,000	113,000
AlaTenn	32,000	42,000	40,000	59,000
KPC	19,000	8,000	31,000	29,000
Bamagas	162,000	110,000	94,000	44,000
Other major intrastates	158,000	164,000	156,000	197,000
Total	2,672,000	2,298,000	2,496,000	2,235,000

(1) In December 2005, we sold the South Texas assets and a sour gas system in East Texas which had a combined average daily volume for both the three and nine months ended September 30, 2005 of approximately 57,000 MMBtu/d.

Three months ended September 30, 2006 compared with three months ended September 30, 2005

Our Natural Gas segment produced $43.0 million of operating income in the third quarter of 2006, an increase of $21.4 million from $21.6 million of operating income generated in the corresponding period of 2005. The increase in operating income is primarily attributable to favorable commodity prices which contributed to higher revenue generated by our processing assets in excess of the cost we incur for the natural gas used in processing. Additionally, operating income was higher due to volume increases on each of our major systems resulting from additional wellhead supply contracts and the expansion of our transportation and processing capacity.

Average daily volumes on our major natural gas systems were up approximately 16% in the third quarter of 2006, compared with the corresponding period in 2005. We have continued to experience volume growth in the areas served by our natural gas assets as a result of additional wellhead supply contracts, predominantly on our East Texas, North Texas and Anadarko systems. Drilling activity continues to be robust in the Anadarko Basin, Bossier Trend and Barnett Shale areas served by our systems. Also contributing to the increase in volumes is an 80-mile pipeline we acquired in April 2006 that is complimentary to our existing East Texas system and provided approximately 60,000 MMBtu/d of incremental volume. We expect increasing volumes on our major natural gas systems to result from our continuing investments to expand the capacity of our systems.

During the first two months of the third quarter of 2006, NGL and crude oil prices remained high relative to natural gas prices which have declined from the high prices reached in late 2005. As a result of this pricing environment, the revenue generated by our processing assets less the cost of natural gas purchased for processing was greater than the amounts we realized in the comparable period of 2005. Late in the third quarter, NGL and Crude oil prices began to decline faster than natural gas prices which may reduce revenue from our processing assets less the cost of natural gas purchased for processing during the remainder of 2006. A variable element of the Natural Gas segment's operating income is derived from keep-whole processing of natural gas. Operating income derived from our keep-whole processing for the three months ended September 30, 2006, was approximately $16 million, compared with approximately $9 million for the same period in 2005.

A portion of our Natural Gas segment is exposed to commodity price risks associated with percent of proceeds, percent of liquids, or 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. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will 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 third quarter of 2006 includes unrealized non-cash, mark-to-market net gains of $1.8 million, including $1.4 million of losses due to hedge ineffectiveness. In the third quarter of 2005, our operating income was reduced by $9.5 million of unrealized, non-cash, market-to-market losses that we incurred, primarily from derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The non-cash market-to market losses in the third quarter of 2005 were partially due to natural gas supply disruptions caused by hurricanes Rita and Katrina that caused an increase in natural gas prices. The non-cash mark-to-market net gains in 2006 are primarily 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, above and below under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

The positive growth in our natural gas and NGL gathering, processing and transportation volumes for the third quarter of 2006 was partially offset by increases in operating costs that are mostly related to volume growth and somewhat variable with volumes. The increase in operating and administrative costs is attributable to the continuing growth and expansion of our natural gas systems. As a result of the increase in volumes and the physical growth of our major systems, we have experienced an increase in workforce related costs associated with the operation of these assets. Workforce related costs in addition to the cost of material and supplies have increased as a result of the expansion projects we are constructing to extend the service capability of our existing systems. Additionally, repair and maintenance costs were higher due to pipeline integrity work and compressor maintenance performed during the quarter.

We expect workforce related costs in addition to the cost of materials and supplies to continue increasing as a result of the large number of pipeline expansions being performed in our industry that are causing competitive constraints across the United States. Our ability to attract and retain the resources necessary to complete our expansion projects may be affected by these constraints in the future causing additional increases in workforce related cost. In addition, our ability to obtain materials and supplies at competitive rates given the high demand in our industry for such materials as pipe and compression may also increase operating and capital costs in the future.

Nine months ended September 30, 2006 compared with nine months ended September 30, 2005

Our Natural Gas segment produced $118.9 million of operating income in the first nine months of 2006, an increase of $50.2 million from the $68.7 million of operating income generated in the corresponding period of 2005.

Average daily volumes on our major natural gas systems increased 12%, or approximately 261,000 MMBtu/d, for the nine months ended September 30, 2006, compared with the corresponding period in 2005. The increase in volumes is consistent with the reasons cited above in our three-month analysis.

As previously noted under our three-month analysis, a portion of our Natural Gas segment's operating income is derived from processing natural gas under keep-whole arrangements. Operating income derived from keep-whole processing on our major systems increased to approximately $44 million for the nine months ended September 30, 2006, compared with approximately $19 million for the corresponding period in 2005 for the same reasons discussed above in our three-month analysis.

Operating income of our Natural Gas segment for the nine months ended September 30, 2006 includes non-cash, mark-to-market net losses of $0.1 million, including $1.5 million of losses due to hedge ineffectiveness. In the nine months ended September 30, 2005, our operating income was reduced by the $22.6 million of non-cash, mark-to-market losses that we incurred for derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and $1.9 million of losses due to hedge ineffectiveness. The non-cash mark-to-market net losses in 2006 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 $24.3 million greater for the nine months ended September 30, 2006, than for the corresponding period in 2005. The increase in operating and administrative costs of our Natural Gas segment increased for the same reasons discussed above in our three-month analysis.

Future Prospects Update for Natural Gas

We continue to assess various acquisition and expansion opportunities to pursue our strategy for growth. The market for acquiring energy transportation assets continues to remain active and significant competition among prospective acquirers of assets persists. 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. Although one of our objectives is to grow our natural gas business through acquisitions, 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 nine months of 2006, increased drilling in the areas where our gathering systems are located has continued to contribute to our volume growth. We expect the growth trend in these areas to continue as indicated by an external production forecast and the robust drilling indicated by rig counts in the areas served by our systems.

In the first nine months of 2006, we have completed the following projects:

- The expansion of our existing Zybach processing facility to a capacity of 150 million cubic feet per day, or MMcf/d, of natural gas from the initial capacity of approximately 105 MMcf/d when we placed the plant in service in April 2005.
- The link between our North Texas and East Texas systems became fully operational during the third quarter of 2006. As expected, the completion of this connection has increased the utilization of our 500 MMcf/d intrastate pipeline that we placed in service in June 2005 on our East Texas system by providing additional market access to customers of our North Texas system.
- The 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. In the fourth quarter of 2006, we expect the addition of this processing facility to begin contributing to the favorable return we are experiencing on our processing assets.

In the East Texas region, we initiated construction on several projects during 2006 to increase our gathering and treating infrastructure and market access capability. These projects continue to progress according to schedule and include:

- A 36-inch diameter intrastate pipeline from Bethel, Texas to Orange County, Texas with capacity of approximately 700 MMcf/d, to be completed in stages throughout 2007. The new pipeline will provide service to a number of major industrial and power companies in Southeast Texas and will cross a number of interstate pipelines. We currently anticipate the expansion project will cost approximately $610 million.
- A 200 MMcf/d treating facility to be built near Marquez, Texas will be connected to the 36-inch diameter intrastate pipeline via a new 24-inch diameter pipeline, to be completed in early 2007.
- A number of upstream facilities, including gathering pipelines to tie existing facilities into the new intrastate pipeline, will also be completed in early 2007.

On our North Texas system, we commenced construction of a new 35 MMcf/d gas processing plant and related upstream facilities to accommodate anticipated growth in the region. These facilities are expected to become operational in the first half of 2007.

The rate of growth on our Anadarko system continues to exceed projections as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties. To accommodate this continuing volume growth, the Anadarko system requires additional processing capacity and field compression. We are continuing to make progress in increasing processing capacity and field compression in the region from 230 MMcf/d at December 31, 2005 to approximately 440 MMcf/d to accommodate the volume growth. We have added approximately 50 MMcf/d of processing capacity during 2006 and expect to place the additional processing capacity and field compression in service in early 2007.

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

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. In April 2006, Calpine announced its intent to sell approximately 20 of its non-core and non-strategic power plants, although the plants to be sold have not been announced. Calpine has continued to perform under the terms of its agreement with Bamagas and 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 September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(unaudited; in millions)			
Operating revenues	$718.5	$1,107.6	$2,239.8	$2,544.5
Cost of natural gas	697.9	1,145.9	2,190.8	2,582.5
Operating and administrative	1.1	1.4	3.7	3.1
Depreciation and amortization	0.1	0.1	0.3	0.4
Operating Expenses	699.1	1,147.4	2,194.8	2,586.0
Operating Income (loss)	$ 19.4	$ (39.8)	$ 45.0	$ (41.5)

Three months ended September 30, 2006 compared with three months ended September 30, 2005

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 the Partnership's 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.

In the third quarter of 2006, the operating income of our Marketing segment increased $59.2 million to $19.4 million, from a loss of $39.8 million for the corresponding period in 2005. Included in operating income for the third quarter of 2006 are unrealized, non-cash, mark-to-market gains of approximately $21.9 million compared with unrealized mark-to-market losses of $43.1 million for the comparable period in 2005, associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The unrealized, mark-to-market gains for the three months ended September 30, 2006, are the result of a decline in the forward and daily market price of natural gas from the historically high prices experienced at September 30, 2005. We expect these net mark-to-market gains to be offset when the related physical transactions are settled (refer also to the discussion included below under Derivative Activities, Note 10 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

The operating results of our Marketing business for the three months ended September 30, 2006, include a non-cash charge of $6.6 million to adjust the cost basis of our natural gas inventory to fair market value at September 30, 2006. Natural gas prices as published by Gas Daily for Henry Hub were approximately $6.09 per MMBtu at June 30, 2006, which had declined to $4.18 per MMBtu at September 30, 2006. As a result of this near-term decline in the price of natural gas at our storage locations from June 30, 2006 to September 30, 2006, the weighted average cost of our natural gas inventory at September 30, 2006, exceeded the market price of natural gas by approximately $6.6 million. As a result of this decline, we reduced the cost basis of our inventory to fair market value at September 30, 2006, by recording a non-cash charge for $6.6 million. Partially offsetting this charge are gains of approximately $2 million that we realized upon settlement of derivative financial instruments hedging our natural gas inventory. Due to our hedging structures, we expect that a majority of this charge will be offset by future financial and physical transactions that will settle at the time the natural gas inventory is sold.

Nine months ended September 30, 2006 compared with nine months ended September 30, 2005

In the first nine months of 2006, the operating income of our Marketing segment increased $86.5 million to $45.0 million, from a loss of $41.5 million for the corresponding period in 2005. Included in operating income for the first nine months of 2006 are unrealized, non-cash, mark-to-market net gains of approximately $53.2 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 losses of $46.8 million for the comparable period in 2005. In the third quarter of 2005, we recognized approximately $9.0 million of losses for the discontinuance of hedge accounting for derivative financial instruments associated with forecasted transactions that we determined were not probable of occurring (refer also to the discussion included below under Derivative Activities, Note 10 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk). These mark-to-market gains are primarily driven by the decline in natural gas prices since December 31, 2005, as discussed above in our three-month analysis.

The operating results of our Marketing business for the nine months ended September 30, 2006, include a non-cash loss of $16.3 million attributable to reducing the cost basis of our natural gas inventory to fair market value. Natural gas prices as published by Gas Daily for Henry Hub were approximately $10.08 per MMBtu at December 31, 2005, which had declined to $4.18 per MMBtu at September 30, 2006. As a result of the decline in the price of natural gas from December 31, 2005 to September 30, 2006, we recorded charges totaling $16.3 million during the nine months ended September 30, 2006 to reduce the cost basis of our inventory to fair market value. Partially offsetting this charge are gains of approximately $3 million that we realized upon settlement of derivative financial instruments hedging our natural gas inventory. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial and physical transactions that will settle at the time the natural gas inventory is sold.

Corporate

Interest expense was $28.5 million and $84.0 million for the three and nine months ended September 30, 2006, respectively, compared with $28.4 million and $79.6 million, respectively, for the corresponding periods in 2005. The increase is the result of higher debt balances and weighted average interest rates, partially offset by approximately $2.3 million and $5.7 million of interest capitalized on our construction projects for the three and nine months ended September 30, 2006, respectively, compared to $0.2 million and $3.4 million, respectively, for the corresponding periods in 2005. Our weighted average interest rate was approximately 5.86% for the three and nine months ended September 30, 2006, compared with approximately 5.68% and 5.80%, respectively, during the corresponding periods in 2005.

Included in other income for the nine months ended September 30, 2006, is $4.5 million that we received as settlement for an insurance claim that we filed in connection with an interruption to the operations of our Lakehead system resulting from a fire that occurred at Suncor's upgrader site in January 2005.

The Partnership is not a taxable entity for U.S. federal income tax purposes and historically has not been a taxable entity for state income tax purposes. Federal and state income taxes on partnership taxable income were both borne directly by the unitholders with no entity level tax on the Partnership. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by imposing a new tax based upon modified gross revenue referred to as the "Margin Tax." We determined the "Margin Tax" to be an income tax as defined under Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("SFAS No. 109"). Our initial accounting for the enactment of this income tax did not materially affect our results of operation, financial condition or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

General

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

In 2005, we shifted our business strategy to an emphasis on 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 expansion and other related projects associated with our Lakehead system (see Liquids segment—Future Prospects), will require significant expenditures of capital over the next several years. We expect to permanently fund these expenditures from a balanced combination of additional issuances of partnership capital and long-term debt. Our planned internal growth projects will require us to bear the cost of constructing these new assets before we will begin to realize a return on them. While these major projects are under construction, our ability to increase distributions is likely to be limited.

Capital Resources

Available Credit

A significant source of our liquidity is provided by the commercial paper market. We have a $600 million commercial paper program 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. Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $400 million. At September 30, 2006, we had $475 million in principal amount of commercial paper outstanding and could issue an additional $125 million in principal amount of commercial paper. We expect to extend the capacity of our commercial paper program to approximately $800 million, which extension will be subject to receipt of satisfactory credit ratings from the major credit rating agencies.

Our Credit Facility also provides us with another significant source of liquidity. In March 2006, we obtained an increase from $800 million to $1 billion in the aggregate commitment available to us under the terms of our 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 September 30, 2006 we had no amounts outstanding under our Credit Facility and letters of credit totaling $59.1 million. At September 30, 2006, we could borrow $465.9 million under the terms of our Credit Facility after reducing the $1 billion commitment amount by outstanding letters of credit and the principal balance of commercial paper we have outstanding. We expect to extend the capacity of our Credit Facility to approximately $1.5 billion in the near term, subject to approval of the lenders that are party to our Credit Facility. Subject to the expansion of our Credit Facility, we will consider further extending the capacity of our commercial paper program to $1 billion.

Unit Issuance

In August 2006, we received net proceeds of approximately $510 million from the issuance of our Class C units, including approximately $10 million contributed by our general partner to maintain its two percent general partner interest. Proceeds from the issuance were partially used to reduce borrowings outstanding under our commercial paper program and to fund our capital expansion projects. We invested the remaining amount in short-term commercial paper for use in future periods to further reduce our commercial paper borrowings or fund additional expenditures under our capital expansion projects.

Cash Requirements for Future Growth

Capital Spending

We rely upon cash flow from our operating activities and access to the capital markets to provide the funds necessary to execute our growth strategy and complete our projects. Our success with generating and raising capital is a critical factor that determines how much we spend in connection with our growth objectives. We believe our ability to generate or otherwise access the necessary capital resources is sufficient to meet the demands of our current and future operating growth needs. Although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in economic conditions.

We estimate our capital expenditures based on our long range strategic operating and growth plans. These estimates may change due to factors beyond our control, including changes in supplier prices, resource constraints and poor economic conditions. Additionally, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or operational considerations.

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 made capital expenditures of approximately $514.3 million, including $34.0 million on core maintenance activities, during the nine months ended September 30, 2006.

For the full year of 2006, we anticipate our capital expenditures to approximate the following (in millions):

System enhancements	$400
Core maintenance activities	50
Southern Access expansion	165
East Texas expansion	350
	$965

We continue to expect our ongoing capital expenditures to be significant over the next three years due to the East Texas expansion and Southern Access expansion projects. Our outlays for capital expenditures may increase as a result of the number of pipeline expansion projects being conducted in the United States and the resulting demand these projects create for skilled labor and supply resources. Our ability to attract the resources necessary to complete our expansion projects may be negatively affected by the heavy demand for these resources.

We anticipate funding our 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.

Our Southern Access and East Texas expansion projects have strong support from our customers, and upon completion each project is expected to have stable cash flows. Although, we have received indications that these projects can be readily financed, we intend to structure the capacity of our Credit Facility to support temporary expansion of our commercial paper program which will be refinanced with permanent capital at key milestone dates for each project.

As of September 30, 2006, we have contractual commitments totaling $402.9 million for materials and services related to our organic growth projects. We anticipate settling these commitments during the remainder of 2006; however, we expect to make additional commitments as our capital projects continue to progress.

We also 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 consistent with industry trends.

Acquisitions

We continue to assess various acquisition and expansion opportunities to grow our business. However, the market for acquiring energy transportation assets remains competitive. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will focus our efforts on development of our existing pipeline systems. Additionally, we may pursue opportunities to divest any non-strategic assets as conditions warrant.

We expect that the funds needed to achieve growth through acquisitions will be obtained through issuances of commercial paper, term debt and additional partnership interests.

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 September 30, 2006 for each of the indicated calendar years:

	Notional	2006	2007	2008	2009	2010	2011	2012
				($ in millions)				
Swaps								
Natural gas[1]	343,052,395	$(10.7)	$(37.9)	$(34.9)	$(28.3)	$(23.9)	$(21.5)	$(4.7)
NGL[2]	8,961,934	(4.6)	(9.5)	(5.4)	(0.1)	(0.9)	—	—
Crude[2]	1,261,164	(2.0)	(9.7)	(7.3)	(2.0)	(0.5)	(0.1)	—
Options—calls								
Natural gas[1]	1,918,000	(0.1)	(1.2)	(1.2)	(1.2)	(1.1)	(1.0)	—
Options—puts								
Natural gas[1]	1,887,000	—	—	—	—	0.1	0.1	—
Totals		$(17.4)	$(58.3)	$(48.8)	$(31.6)	$(26.3)	$(22.5)	$(4.7)

(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 our operating activities for the nine months ended September 30, 2006 was $229.9 million, an increase of $21.7 million over the $208.2 million we generated for the same period in 2005. The improved operating cash flow is primarily attributable to income contributions from our natural gas processing assets and increased deliveries on our Lakehead system, partially offset by general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $87.5 million more in our investing activities during the nine months ended September 30, 2006 compared with the same period in 2005. The decrease in expenditures for acquisitions was more than offset by the $252.4 million increase in our investments in property, plant and equipment during the first nine months of 2006 over the amount spent during the same period of 2005. The increase in our capital expenditures in the first nine months of 2006 is directly attributable to our previously announced expansion projects and a result of our shift in strategy to more internal growth projects.

Financing Activities

Net cash provided by our financing activities during the nine months ended September 30, 2006 was $463.7 million, compared with $249.2 million for the corresponding period in 2005. The increase in our cash flows from financing activities is primarily due to proceeds received from the issuance of our Class C units in August 2006. We raised approximately $510 million from the issuance of our Class C units during the first nine months of 2006, which we used to reduce the balance outstanding under our commercial paper program and to fund our capital expansion projects.

In the first nine months of 2005 we raised $127.5 million from the issuance of our Class A units. During the first nine months of 2006 we had net commercial paper issuances of $143.9 million, which include gross issuances of $2,488.2 million and gross repayments of $2,344.3 million. Additionally, at September 30, 2006 we had gross borrowings and gross repayments of $90 million on our Credit Facility and had repaid $20 million in principal amount of an affiliate loan. During the first nine months of 2005, we repaid $175 million, net of borrowings, under the terms of our Credit Facility, including borrowings and repayments of $565 million representing net non-cash settlements with the parties to our Credit Facility.

Distributions to our partners were higher in the first nine months of 2006 due to an increase in the weighted average number of units outstanding in relation to the first nine months of 2005 and the related increase in the general partner incentive distributions resulting from the larger number of units outstanding.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On October 27, 2006, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2006. The distribution will be paid to unitholders of record as of November 6, 2006, of our available cash of $79.6 million at September 30, 2006, or $0.925 per limited partner unit. Of this distribution, $57.6 million will be paid in cash, $11.5 million will be distributed in i-units to our i-unitholder, $10.1 million will be distributed in Class C units to the holders of our Class C units and $0.4 million will be retained from the General Partner in respect to the i-unit and Class C unit distributions.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

Beginning July 1, 2006, 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 established a new oil pipeline pricing index for a five-year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPIFG+1.3 percent) should be the oil pricing index for the five year period beginning July 1, 2006. For our Lakehead system indexing only applies to our base rates and not the SEP II, Terrace and Facilities surcharges. Beginning July 1, 2006, we increased our rates for transportation on our Lakehead system by an average of 3.0 percent, which is less than the amount allowed under the index. As an example, on our Lakehead system, the new rate for heavy crude movements from the International Boarder near Neche, North Dakota to Chicago, Illinois is $0.919 per barrel, which reflects an approximate $0.021 per barrel increase over rates filed effective April 1, 2006. In addition to the rates on our Lakehead system, we increased the transportation rates by an average of approximately 6.1 percent on our North Dakota and Ozark systems.

Effective April 1, 2006, we filed our annual tariff with the FERC for our Lakehead System SEP II expansion. This tariff reflected the annual calculation of the SEP II and other surcharges based on true-ups of prior year amounts and estimates for 2006, and an adjustment for the Terrace surcharge as a result of lower than expected volumes moving on the Lakehead system in 2005. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.008 per barrel, to approximately $0.898 per barrel.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157, *Fair Value Measurements.* This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurement. The statement is effective for fiscal years beginning after November 15, 2007, and with limited exceptions is to be applied prospectively as of the beginning of the fiscal year initially adopted. We do not expect our adoption of this pronouncement to materially effect our financial statements. However, adoption of this pronouncement may affect our disclosures regarding derivative financial instruments and indebtedness.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K for the year ended December 31, 2005, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, natural gas liquids (“NGL” or “NGLs”), condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). This market price exposure 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.

The following tables provide information about our derivative financial instruments at September 30, 2006 and December 31, 2005, with respect to our commodity price risk management activities for natural gas and NGLs, including crude oil:

	At September 30, 2006						At December 31, 2005	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2006								
Swaps								
Receive variable/pay fixed	Natural gas	31,746,904	$ 5.08	$ 7.39	$ 1.3	$(74.1)	$380.6	$ (11.7)
	NGL	25,116	39.20	46.29	—	(0.2)	—	—
Receive fixed/pay variable	Natural gas	31,476,769	7.30	5.28	68.7	(5.4)	14.5	(467.8)
	NGL	1,208,880	36.13	39.79	1.6	(6.0)	—	(29.7)
	Crude oil	101,660	44.18	64.36	—	(2.0)	0.2	(7.8)
Receive variable/pay variable	Natural gas	12,763,662	4.18	4.27	0.8	(2.0)	5.2	(5.2)
Options								
Calls (written)	Natural gas	92,000	5.79	4.31	—	(0.1)	—	(2.0)
Puts	Natural gas	61,000	6.50	3.40	—	—	—	—
Contracts maturing in 2007								
Swaps								
Receive variable/pay fixed	Natural gas	66,117,198	7.12	7.58	18.2	(47.8)	112.0	(1.0)
	NGL	99,645	38.41	43.65	—	(0.5)	—	—
Receive fixed/pay variable	Natural gas	65,858,920	7.32	7.46	41.2	(49.7)	0.5	(170.0)
	NGL	4,296,415	38.18	40.35	13.4	(22.4)	—	(22.5)
	Crude oil	388,680	42.05	68.02	—	(9.7)	—	(7.9)
Receive variable/pay variable	Natural gas	15,959,366	7.51	7.50	1.0	(0.8)	0.7	(0.1)
Options								
Calls (written)	Natural gas	365,000	7.67	4.31	—	(1.2)	—	(2.0)
Puts	Natural gas	365,000	7.67	3.40	—	—	—	—
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	16,668,457	7.60	7.35	9.7	(5.8)	18.5	—
Receive fixed/pay variable	Natural gas	24,087,303	6.27	8.06	4.3	(44.0)	—	(66.3)
	NGL	1,607,253	37.26	40.90	2.1	(7.5)	—	(7.2)
	Crude oil	323,699	44.18	68.82	—	(7.3)	—	(5.2)
Receive variable/pay variable	Natural gas	16,847,541	8.25	8.19	1.4	(0.5)	1.0	—
Options								
Calls (written)	Natural gas	366,000	7.99	4.31	—	(1.2)	—	(1.7)
Puts	Natural gas	366,000	7.99	3.40	—	—	—	—

	At September 30, 2006						At December 31, 2005	
			Wtd Avg Price[(2)]		Fair Value[(3)]		Fair Value[(3)]	
	Commodity	Notional[(1)]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed....	Natural gas	4,611,085	7.37	7.24	3.0	(2.5)	—	—
Receive fixed/pay variable....	Natural gas	12,865,240	5.15	7.78	1.0	(30.5)	—	(34.5)
	NGL	1,407,075	41.05	41.08	1.3	(1.4)	—	(0.6)
	Crude oil	191,625	55.63	67.40	—	(2.0)	—	(1.0)
Receive variable/pay variable .	Natural gas	16,277,500	8.02	7.97	1.2	(0.5)	1.1	—
Options								
Calls (written)	Natural gas	365,000	7.74	4.31	—	(1.2)	—	(1.4)
Puts	Natural gas	365,000	7.74	3.40	—	—	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed....	Natural gas	761,950	7.59	3.80	2.4	—	—	—
Receive fixed/pay variable....	Natural gas	9,490,000	4.11	7.51	0.1	(26.9)	0.1	(25.9)
	NGL	317,550	30.60	34.20	—	(0.9)	—	(0.4)
	Crude oil	146,000	61.04	65.62	—	(0.5)	—	(0.1)
Receive variable/pay variable .	Natural gas	7,200,000	8.35	8.26	0.7	(0.2)	—	—
Options								
Calls (written)	Natural gas	365,000	7.55	4.31	—	(1.1)	—	(1.1)
Puts	Natural gas	365,000	7.55	3.40	0.1	—	—	—
Contracts maturing after 2010								
Swaps								
Receive variable/pay fixed....	Natural gas	912,000	7.61	3.57	2.9	—	—	—
Receive fixed/pay variable....	Natural gas	9,408,500	3.62	7.56	—	(29.1)	—	(26.1)
	Crude oil	109,500	62.95	64.04	—	(0.1)	—	—
Options								
Calls (written)	Natural gas	365,000	7.40	4.31	—	(1.0)	—	(0.9)
Puts	Natural gas	365,000	7.40	3.40	0.1	—	—	—

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2006 and December 31, 2005, 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.

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 financial instruments we utilize.

Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas in our Consolidated Statements of Income. 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 ("OCI"), 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 OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI 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. However, we have four primary transaction types where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated financial instrument contract settlement is made.

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

1. **Transportation**—In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, these derivative financial instruments are marked-to-market.
2. **Storage**—In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas

may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from when the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index to better match the indices. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical, and ceasing to do so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing. We will designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we utilize for the derivative financial instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

The following table presents the 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 September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ (1.4)	$ 0.1	$ (1.5)	$ (1.9)
Non-qualified hedges	3.2	(9.6)	1.4	(20.7)
Marketing				
Non-qualified hedges	21.9	(43.1)	53.2	(37.8)
Discontinued hedges	—	—	—	(9.0)
Derivative fair value gains (losses)	$23.7	$(52.6)	$53.1	$(69.4)

We record the change in fair value of our cash flow hedges in OCI until the derivative financial instruments are settled, at which time they are reclassified from OCI to earnings. Also included in OCI are unrecognized losses of approximately $5.6 million associated with cash flow hedges that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three and nine months ended September 30, 2006, we reclassified losses of $24.0 million and $63.7 million, respectively, from OCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

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

	September 30, 2006	December 31, 2005
	(in millions)	
Other current assets	$ 5.9	$ 5.8
Other assets, net	5.9	4.2
Accounts payable and other	(64.2)	(129.2)
Other long-term liabilities	(161.3)	(243.0)
	$(213.7)	$(362.2)

The decrease in our obligation associated with derivative activities is primarily due to the decline in current and forward natural gas prices from December 31, 2005 to September 30, 2006. 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.

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 September 30, 2006. 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 nine months ended September 30, 2006, 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, 2005.

Our partnership agreement and the delegation of control agreement limit the fiduciary duties that Enbridge Management and our general partner owe to our unitholders and restrict the remedies available to our unitholders for actions taken by Enbridge Management and our general partner that might otherwise constitute a breach of a fiduciary duty.

Our partnership agreement contains provisions that modify the fiduciary duties that our general partner would otherwise owe to our unitholders under state fiduciary duty law. Through the delegation of control agreement, these modified fiduciary duties also apply to Enbridge Management as the delegate of our general partner. For example, our partnership agreement:

- permits our general partner to make a number of decisions, including the determination of which factors it will consider in resolving conflicts of interest, in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;
- provides that any standard of care and duty imposed on our general partner will be modified, waived or limited as required to permit our general partner to act under our partnership agreement and to make any decision pursuant to the authority prescribed in our partnership agreement, so long as such action is reasonably believed by the general partner to be in our best interests; and
- provides that our general partner and its directors and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions if they acted in good faith.

These and similar provisions in our partnership agreement may restrict the remedies available to our unitholders for actions taken by Enbridge Management or our general partner that might otherwise constitute a breach of a fiduciary duty.

Potential conflicts of interest may arise among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Because the fiduciary duties of the directors of our general partner and Enbridge Management have been modified, the directors may be permitted to make decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders.

Conflicts of interest may arise from time to time among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Conflicts of interest may also arise from time to time between us and our unitholders, on the one hand, and Enbridge Management and its shareholders, on the other hand. In managing and controlling us as the delegate of our general partner, Enbridge Management may consider the interests of all parties to a conflict and may resolve those conflicts by making decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders. The following decisions, among others, could involve conflicts of interest:

- whether we or Enbridge Inc. will pursue certain acquisitions or other business opportunities;

- whether we will issue additional units or other equity securities or whether we will purchase outstanding units;
- whether Enbridge Management will issue additional shares;
- the amount of payments to Enbridge and its affiliates for any services rendered for our benefit;
- the amount of costs that are reimbursable to Enbridge Management or Enbridge and its affiliates by us;
- the enforcement of obligations owed to us by Enbridge Management, our general partner or Enbridge, including obligations regarding competition between Enbridge and us; and
- the retention of separate counsel, accountants or others to perform services for us and Enbridge Management.

In these and similar situations, any decision by Enbridge Management may benefit one group more than another, and in making such decisions, Enbridge Management may consider the interests of all groups, as well as other factors, in deciding whether to take a particular course of action.

In other situations, Enbridge may take certain actions, including engaging in businesses that compete with us, that are adverse to us and our unitholders. For example, although Enbridge and its subsidiaries are generally restricted from engaging in any business that is in direct material competition with our businesses, that restriction is subject to the following significant exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of our initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which we provided transportation at the time of our initial public offering;
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge's reasonable judgment, is not attributable to the competitive business; and
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us if that business is first offered for acquisition to us and the board of directors of Enbridge Management and our unitholders determine not to pursue the acquisition.

Since we were not engaged in any aspect of the natural gas business at the time of our initial public offering, Enbridge and its subsidiaries are not restricted from competing with us in any aspect of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as our Lakehead system, even if such transportation is in direct material competition with our business.

These exceptions also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia, Ontario to Montreal, Quebec. As a result of this reversal, Enbridge competes with us to supply crude oil to the Ontario, Canada market.

Item 6. 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 Third Amended and Restated Agreement of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002).

3.4 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 August 15, 2006, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K dated August 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.

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: October 30, 2006

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

Date: October 30, 2006

By: /s/ MARK A. MAKI
Mark A. Maki
Vice President, Finance
(Principal Financial Officer)