UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 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 April 28, 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 March 31, 2006	2005
	(unaudited; in millions, except per unit amounts)	
Operating revenue	$1,888.6	$1,250.1
Operating expenses		
Cost of natural gas (Note 3 and 4)	1,647.7	1,072.2
Operating and administrative	73.9	74.4
Power	26.3	17.0
Depreciation and amortization (Note 6)	32.7	33.3
	1,780.6	1,196.9
Operating income	108.0	53.2
Interest expense	(27.9)	(25.6)
Other income	1.0	0.6
Net income	$ 81.1	$ 28.2
Net income allocable to common and i-units	$ 73.9	$ 22.2
Net income per common and i-unit (basic and diluted) (Note 2)	$ 1.12	$ 0.37
Weighted average units outstanding	65.7	60.6

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 March 31,	
	2006	2005
	(unaudited; in millions)	
Net income	$ 81.1	$ 28.2
Other comprehensive income (loss) (Note 4)	34.1	(74.2)
Comprehensive income (loss)	$115.2	$(46.0)

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31, 2006	2005
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 81.1	$ 28.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	32.7	33.3
Derivative fair value (gain) loss (Note 4)	(27.7)	7.0
Inventory market price adjustment (Note 3)	8.0	—
Other	(1.1)	(0.3)
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	(15.7)	(6.9)
Due from General Partner and affiliates	(1.3)	1.8
Accrued receivables	105.5	31.2
Inventory	26.7	15.5
Current and long-term other assets	(0.5)	(0.7)
Due to General Partner and affiliates	1.9	(7.8)
Accounts payable and other	(36.8)	(15.0)
Accrued purchases	(101.7)	(18.5)
Interest payable	19.9	21.2
Property and other taxes payable	5.4	0.3
Net cash provided by operating activities	96.4	89.3
Cash used in investing activities		
Additions to property, plant and equipment	(98.7)	(72.9)
Changes in construction payables	(6.8)	(6.7)
Asset acquisitions, net of cash acquired	—	(165.7)
Other	(0.3)	(0.7)
Net cash used in investing activities	(105.8)	(246.0)
Cash provided by financing activities		
Proceeds from unit issuances, net	—	127.5
Distributions to partners (Note 8)	(56.6)	(50.7)
Borrowings under credit facilities, net	—	70.0
Net issuances of commercial paper	110.0	—
Other	—	0.1
Net cash provided by financing activities	53.4	146.9
Net increase (decrease) in cash and cash equivalents	44.0	(9.8)
Cash and cash equivalents at beginning of year	89.8	78.3
Cash and cash equivalents at end of period	$ 133.8	$ 68.5

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2006	December 31, 2005
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 133.8	$ 89.8
Receivables, trade and other, net of allowance for doubtful accounts of $4.9 in 2006 and $4.5 in 2005	125.4	109.7
Due from General Partner and affiliates	21.4	20.1
Accrued receivables	509.8	615.3
Inventory (Note 3)	104.2	138.9
Other current assets	5.4	11.5
	900.0	985.3
Property, plant and equipment, net (Note 6)	3,148.0	3,080.0
Other assets, net	24.9	22.2
Goodwill	258.2	258.2
Intangibles, net	81.7	82.7
	$4,412.8	$4,428.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 14.4	$ 12.5
Accounts payable and other (Note 5)	164.9	247.9
Accrued purchases	545.0	646.7
Interest payable	28.8	11.4
Property and other taxes payable	27.2	21.8
Current maturities of long-term debt	31.0	31.0
	811.3	971.3
Long-term debt (Note 7)	1,792.5	1,682.9
Loans from General Partner and affiliates	154.3	151.8
Environmental liabilities (Note 9)	5.2	4.8
Other long-term liabilities (Note 4)	227.3	253.8
	2,990.6	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)	1,152.2	1,142.4
Class B common units (Units issued—3,912,750 in 2006 and 2005)	68.1	67.2
i-units (Units issued—11,933,019 in 2006 and 11,704,948 in 2005)	434.8	421.7
General Partner	35.1	34.6
Accumulated other comprehensive loss (Note 4)	(268.0)	(302.1)
	1,422.2	1,363.8
	$4,412.8	$4,428.4

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the financial position as of March 31, 2006 and December 31, 2005, the results of operations and cash flows for the three month periods ended March 31, 2006 and 2005. The results of operations for the three month period ended March 31, 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 and differentials 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 COMMON AND i-UNIT

Net income per common and i-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 Class A and Class B common units and i-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 common and i-unit was determined as follows:

	Three months ended March 31, 2006	Three months ended March 31, 2005
	(in millions, except per unit amounts)	
Net income	$81.1	$28.2
Allocations to the General Partner:		
Net income allocated to General Partner	(1.6)	(0.6)
Incentive distributions to General Partner	(5.6)	(5.3)
Historical cost depreciation adjustments	—	(0.1)
	(7.2)	(6.0)
Net income allocable to common and i-units	$73.9	$22.2
Weighted average units outstanding	65.7	60.6
Net income per common and i-unit (basic and diluted)	$1.12	$0.37

3. INVENTORY

Inventory is comprised of the following:

	March 31, 2006	December 31, 2005
	(dollars in millions)	
Material and supplies	$ 8.4	$ 8.3
Liquids inventory	8.8	11.1
Natural gas and NGL inventory	87.0	119.5
	$104.2	$138.9

We recorded an $8.0 million reduction to the cost basis of our natural gas inventory to reflect the market value at March 31, 2006, which is included in the Cost of natural gas in our Marketing segment on our Consolidated Statement of Income.

4. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and 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 purchase and sales prices of the commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated 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 to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use 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, a change in the fair market value, both realized and unrealized, is recognized currently in our income statement as a derivative fair value gain (loss) and recorded in Cost of natural gas. 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, a derivative contract is settled when the future physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Accumulated other comprehensive income ("OCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. 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. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the non-cash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting, 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 three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these financial instruments are considered 'non-qualified' under SFAS No. 133. These non-qualified derivative financial instruments must be adjusted to their 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. 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 an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. **Transportation—**In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. **Storage—**In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same 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. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation established at the inception of the hedge.

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 hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices, which was a sound economic hedging strategy. 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 now accounted for in the Consolidated Statements of Income through mark-to-market accounting, 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.

In each of the three instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the financial side of the transaction is recorded at fair market values while the physical side of the transaction is not) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas 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 March 31, 2006	Three months ended March 31, 2005
	(in millions)	
Natural Gas segment		
Ineffectiveness	$ —	$(0.2)
Non-qualified hedges	1.8	(8.2)
Marketing		
Non-qualified hedges	25.9	1.4
Derivative fair value gains (losses)	$27.7	$(7.0)

We record the change in fair value of our highly effective cash flow hedges in OCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in OCI are unrecognized losses of approximately $7.1 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These unrecognized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three months ended March 31, 2006, we reclassified unrealized losses of $24.8 million 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:

	March 31, 2006	December 31, 2005
	(in millions)	
Other current assets	$ 0.8	$ 5.8
Other assets, net	6.4	4.2
Accounts payable and other	(87.9)	(129.2)
Other long-term liabilities	(217.4)	(243.0)
	$(298.1)	$(362.2)

The decrease in our obligation associated with derivative activities from December 31, 2005 to March 31, 2006 is primarily due to the significant decreases in current and forward natural gas prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price 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.

5. 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 $27.2 million at March 31, 2006 and $46.5 million at December 31, 2005, are included in Accounts payable and other on the Consolidated Statements of Financial Position.

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 pipeline system, was reduced from 3.20% to 2.63%. Depreciation expense for the three months ended March 31, 2006 was approximately $2.5 million lower 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 March 31, 2006 and December 31, 2005, we had no amounts outstanding under our Credit Facility and had letters of credit totaling $107.4 million and $149.3 million, respectively. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At March 31, 2006, we could borrow $452.6 million under the terms of our Credit Facility without consideration to additional borrowings under our commercial paper program.

During the three months ended March 31, 2005, we net settled borrowings of approximately $360 million, on a non-cash basis.

Commercial Paper Program

Under the terms of our commercial paper program, we can 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 March 31, 2006, we had outstanding $438.9 million of commercial paper, net of unamortized discount of $1.1 million, bearing interest at a weighted average rate of 4.82%. 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 March 31, 2006, we could issue an additional $160 million in principal amount under our commercial paper program.

8. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") during the three months ended March 31, 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
				(in millions, except per unit amounts)			
January 30, 2006	February 14, 2006	February 7, 2006	$0.925	$67.6	$10.8	$0.2	$56.6

(1) The Partnership has issued 228,071 i-units to Enbridge Management, the sole owner of the Partnership's i-units, during 2006 in lieu of cash distributions.

(2) The Partnership retains an amount equal to 2% of the i-unit distribution from the General Partner in respect of its 2% general partner interest.

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 March 31, 2006 and December 31, 2005, we have recorded $3.5 million and $4.0 million, respectively, in current liabilities and $5.2 million and $4.8 million, respectively, in long-term liabilities, primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

In 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 will recognize in 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. 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 relating to our business segments:

	As of and for the three months ended March 31, 2006				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 122.6	$1,601.9	$966.4	$ —	$2,690.9
Less: Intersegment revenue	—	730.9	71.4	—	802.3
Operating revenue	122.6	871.0	895.0	—	1,888.6
Cost of natural gas (Note 4)	—	773.5	874.2	—	1,647.7
Operating and administrative	28.6	43.7	1.1	0.5	73.9
Power	26.3	—	—	—	26.3
Depreciation and amortization	15.9	16.6	0.1	0.1	32.7
Operating income	51.8	37.2	19.6	(0.6)	108.0
Interest expense	—	—	—	(27.9)	(27.9)
Other income	—	—	—	1.0	1.0
Net income	$ 51.8	$ 37.2	$ 19.6	$ (27.5)	$ 81.1
Total assets	$1,669.5	$2,227.0	$390.9	$125.4	$4,412.8
Capital expenditures (excluding acquisitions)	$ 16.4	$ 81.1	$ 0.4	$ 0.8	$ 98.7

	As of and for the three months ended March 31, 2005				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 96.5	$ 924.6	$693.8	$ —	$1,714.9
Less: Intersegment revenue	—	439.0	25.8	—	464.8
Operating revenue	96.5	485.6	668.0	—	1,250.1
Cost of natural gas (Note 4)	—	406.5	665.7	—	1,072.2
Operating and administrative	31.9	41.1	0.8	0.6	74.4
Power	17.0	—	—	—	17.0
Depreciation and amortization	17.6	15.6	0.1	—	33.3
Operating income	30.0	22.4	1.4	(0.6)	53.2
Interest expense	—	—	—	(25.6)	(25.6)
Other income	—	—	—	0.6	0.6
Net income	$ 30.0	$ 22.4	$ 1.4	$(25.6)	$ 28.2
Total assets	$1,654.5	$1,908.0	$279.0	$ 80.5	$3,922.0
Capital expenditures (excluding acquisitions)	$ 13.1	$ 58.7	$ —	$ 1.1	$ 72.9

11. SUBSEQUENT EVENT

Distribution to Partners

On April 27, 2006, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2006. The distribution will be paid to unitholders of record as of May 5, 2006, of our available cash of $67.9 million at March 31, 2006, or $0.925 per common unit. Of this distribution, $56.7 million will be paid in cash, $11.0 million will be distributed in i-units to our i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

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

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 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 month periods ended March 31:

	2006	2005
	(unaudited; in millions)	
Operating Income		
Liquids	$ 51.8	$ 30.0
Natural Gas	37.2	22.4
Marketing	19.6	1.4
Corporate, operating and administrative	(0.6)	(0.6)
Total Operating Income	108.0	53.2
Interest expense	(27.9)	(25.6)
Other income	1.0	0.6
Net Income	$ 81.1	$ 28.2

Summary Analysis of Operating Results

Liquids

Our Liquids segment produced operating income of $51.8 million for the three months ended March 31, 2006, a 73 percent increase over the $30.0 million earned in the same period of 2005. The following primary factors contributed to the increase in operating income of our Liquids segment:

- 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;
- Shut-in oil production in the Gulf of Mexico that resulted from hurricanes Katrina and Rita caused refinery procurement patterns to shift, increasing the volumes on our Mid-Continent system;
- The annual index rate increase effective July 1, 2005, which increased our average tariffs; and
- Longer hauls on our Lakehead and North Dakota systems.

Natural Gas

Operating income from our Natural Gas segment grew 66 percent to $37.2 million for the three months ended March 31, 2006 over the same period of 2005. The increased contribution of our Natural Gas segment is primarily attributable to the following:

- Additional processing capacity on our Anadarko system and favorable NGL prices have improved the operating results of our processing assets;
- Growth in average daily volumes on our major natural gas systems stemming from additional wellhead supply contracts on the East Texas and Anadarko systems; and
- Continued strong drilling activity in the Anadarko Basin and East Texas Bossier trend.

Marketing

Operating income from our Marketing segment increased by $18.2 million to $19.6 million for the three months ended March 31, 2006 from $1.4 million for the same period in 2005. The increase in operating income of our Marketing segment is predominantly the result two factors:

- Unrealized, non-cash mark-to-market gains of $25.9 million for the quarter that resulted from the change in market value of our derivative financial instruments that do not qualify for hedge accounting; offset partially by
- A non-cash loss of $8.0 million attributable to reducing the cost basis of our natural gas inventory to fair market value associated with the decrease in the market price of natural gas during the quarter.

Derivative Transactions and Hedging Activities

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

During the quarter ended March 31, 2006, natural gas prices began trending lower as a warmer than expected winter reduced the demand for natural gas supplies. However, NGL prices, which tend to move in relation to crude oil prices, have continued to trend higher due to supply instability in the crude oil market. While the natural gas and NGL pricing environment continues to remain volatile, the mark-to-market gains and losses created by this volatility do not affect our cash flow. We expect these non-cash gains and losses to be offset in future quarters as we settle the derivative financial instruments and the underlying physical transactions.

The following table presents the unrealized, non-cash, mark-to-market gains and losses by segment, associated with our derivative financial instruments for the three month periods ended March 31, 2006 and 2005:

Derivative fair value gains (losses)	Three months ended March 31, 2006	2005
	(in millions)	
Natural Gas segment		
Ineffectiveness	$ —	$(0.2)
Non-qualified hedges	1.8	(8.2)
Marketing		
Non-qualified hedges	25.9	1.4
Derivative fair value gains (losses)	$27.7	$(7.0)

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 gains reflected above in our Natural Gas segment at March 31, 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 March 31, 2006	Three months ended March 31, 2005
	(unaudited; in millions)	
Operating Results		
Operating revenue	$122.6	$ 96.5
Operating and administrative	(28.6)	(31.9)
Power	(26.3)	(17.0)
Depreciation and amortization	(15.9)	(17.6)
Operating expenses	(70.8)	(66.5)
Operating Income	$ 51.8	$ 30.0
Operating Statistics		
Lakehead system:		
United States[(1)]	1,161	1,009
Province of Ontario[(1)]	348	327
Total deliveries[(1)]	1,509	1,336
Barrel miles (billions)	100	83
Average haul (miles)	738	689
Mid-Continent system deliveries[(1)]	237	189
North Dakota system deliveries[(1)]	90	89

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

Three months ended March 31, 2006 compared with three months ended March 31, 2005

Our Liquids segment accounted for $51.8 million of operating income during the three months ended March 31, 2006, representing a $21.8 million increase over the same period in 2005. The majority of the increase related to significantly improved results on our Lakehead system, along with stronger performance on our Mid-Continent and North Dakota systems.

Operating revenue for the first quarter of 2006 increased by approximately $26.1 million to $122.6 million from $96.5 million for the same period in 2005. Volumes on our Lakehead system increased approximately 13%, from 1.336 million Bpd during the first quarter of 2005 to 1.509 million Bpd during the same period in 2006, which resulted in higher operating revenue of approximately $10.5 million. The increase in deliveries on our Lakehead system is the result of higher crude oil production in Western Canada primarily from three sources:

1. Suncor, an oil sands producer in Alberta, Canada, had a fire at their upgrader site on January 4, 2005, which affected production for the majority of 2005. In late September 2005,

Suncor announced that repairs to their upgrader site and an expansion were completed. Suncor's production levels have increased since that time.

2. During the first quarter of 2006, the synthetic plants were functioning without as many operational problems as were experienced in the first quarter of 2005. Also, with warmer winter weather in western Canada during 2006, there were fewer seasonal maintenance issues.

3. Lastly, supply from conventional production was higher in the first quarter of 2006, likely in response to the sustained high crude oil prices.

Deliveries on our Mid-Continent system increased 25% to 237,000 Bpd in the first quarter of 2006, as continued shut-in production in the Gulf of Mexico caused refinery procurement patterns to shift in favor of our system.

Increases in average tariffs on all three Liquids systems resulted in higher operating revenue by approximately $9.7 million. These tariff increases were mostly the result of the annual index rate increase of approximately 3.63% allowed by the Federal Energy Regulatory Commission ("FERC") effective July 1, 2005, on our base system tariffs. On our Lakehead system, new tariffs also went into effect on April 1, 2005 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, which were not in effect during the first quarter of 2005. Longer hauls on our North Dakota system also contributed to a higher average tariff, as production in Montana continues to be strong during the first quarter of 2006.

Operating and administrative expenses for the Liquids segment decreased $3.3 million for the first quarter of 2006, compared with the same period in 2005. The decrease is driven primarily from lower oil measurement losses of $6.3 million, offset by higher workforce related costs of approximately $2.2 million.

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

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation losses, which are 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 first quarter of 2006. We expect these improvements to have a continuing positive impact on our oil measurement losses going forward. We estimate that total oil measurement losses for 2006 will be approximately $10 million, compared with $18 million in 2005, assuming crude oil prices remain comparable to 2005 levels.

Power costs increased $9.3 million in the first quarter of 2006, compared with the same period in 2005, primarily due to the higher deliveries on our Lakehead system, along with higher millrates from the power producers. We have experienced a trend of increasing millrates from our power suppliers due to higher natural gas costs.

We recently completed a depreciation study of the Lakehead system that resulted in our extending the useful life of the system from 23 to 26 years in the first quarter of 2006. The effect of this change was a decrease to depreciation expense of approximately $2.5 million for the three months ended March 31, 2006. We expect the impact of the depreciation study to be a reduction of depreciation expense by approximately $10 million for the full year of 2006.

Future Prospects Update for Liquids

Enbridge Inc. ("Enbridge") and the Partnership continue to actively work with our customers to develop transportation options that will allow western Canadian crude oil access to new markets. In 2005, the Partnership and Enbridge announced approval of the 400,000 Bpd Southern Access expansion project, which received endorsement from the Canadian Association of Petroleum Producers ("CAPP"). 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 36-inch, 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system. The design will also permit a further 400,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior, when required by shippers.

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, a trade association that represents a vast majority of the Lakehead system's customers. Fieldwork has commenced on the project to ensure full completion in early 2009. In anticipation of long term demands for pipeline capacity driven by oil sands production, we have decided to further increase the diameter of the pipeline to 42 inches. This increase will bring the estimated cost of the Southern Access expansion project to approximately $1.3 billion. We expect increasing the diameter of the pipeline will benefit the project by lowering power costs and positioning the system for low-cost future expansion after 2009. Further, increasing the diameter of the pipeline will provide an additional 800,000 Bpd of capacity available for transport into the Chicago hub, bringing the total incremental capacity potential to 1.2 million Bpd over the capacity available today.

Subject to the support of our customers, we expect to increase the scope of our previously announced North Dakota system expansion. This expansion will add approximately 30,000 Bpd of mainline throughput capacity and expand the system's feeder segment 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.

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 following the reversal, as western Canadian crude oil will be carried on the 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. Mustang Pipe Line Partners system is 30% owned by an affiliate of Enbridge. Exxon 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 will also be capable of transporting western Canadian crude oil moved via other competing pipelines into the Patoka market.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and average daily volumes of our major systems in MMBtu/d for the periods presented:

	Three months ended March 31,	
	2006	2005
	(unaudited; in millions)	
Operating Results		
Operating revenue	$ 871.0	$ 485.6
Cost of natural gas	(773.5)	(406.5)
Operating and administrative	(43.7)	(41.1)
Depreciation and amortization	(16.6)	(15.6)
Operating expenses	(833.8)	(463.2)
Operating Income	$ 37.2	$ 22.4
Average Daily Volume (MMBtu/d)		
East Texas[(1)]	921,000	787,000
Anadarko	563,000	452,000
North Texas	279,000	265,000
South Texas[(1)]	—	38,000
UTOS	199,000	198,000
MidLab	83,000	105,000
AlaTenn	54,000	83,000
KPC	47,000	59,000
Bamagas	37,000	13,000
Other major intrastates	158,000	220,000
Total	2,341,000	2,220,000

(1) We sold the South Texas assets and a sour gas system in East Texas in December 2005, which had a combined average daily volume for the three months ended March 31, 2005 of approximately 60,000 MMBtu/d.

Three months ended March 31, 2006 compared with three months ended March 31, 2005

Our Natural Gas segment produced $37.2 million of operating income in the first quarter of 2006, an increase of $14.8 million from the $22.4 million of operating income generated in the corresponding period of 2005. The increase in operating income is primarily due to the expansion of our existing processing and transportation capacity to accommodate the additional production volumes that have been developed in the basins served by our natural gas assets, combined with favorable commodity prices.

Average daily volumes on our major natural gas systems were up five percent in the first quarter of 2006, compared with the corresponding period in 2005. The increase in volumes is primarily the result of additional wellhead supply contracted to our East Texas, North Texas and Anadarko systems. Drilling activity continues to increase in the Anadarko Basin, Bossier Trend and Barnett Shale areas served by our systems. Additionally, completion of the East Texas expansion project in late June 2005 contributed to the growth in volumes for the three months ended March 31, 2006. We expect increasing volumes on our major natural gas systems to result from our continuing investments to expand the capacity of our systems.

Also contributing to the increase in operating income of our Natural Gas segment for the first quarter of 2006 are non-cash, mark-to-market net gains of $1.8 million. In the first quarter of 2005, our operating income was reduced by the $8.4 million of losses that we incurred. The non-cash mark-to-market net gains in 2006 are derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 (refer also to the discussions included in Note 4 of Item 1. Financial Statements, below under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

These gains primarily resulted from declines in forward natural gas prices during the quarter. The previously recognized mark-to-market losses associated with our derivative financial instruments are reduced as the price of natural gas moves closer to the contract prices on these derivative financial instruments, producing unrealized, non-cash mark-to-market gains. Declines in the price of natural gas reduce the unrealized losses on our derivative financial instruments because the related contract prices are fixed at amounts that are generally less than the market price of natural gas at each of the forward settlement points. Although changes in the fair value of these specific derivative financial instruments do not affect our cash flow, we anticipate these changes will continue to create volatility in our Consolidated Statements of Income going forward due to the inherent volatility of natural gas and NGL prices.

A portion of our Natural Gas segment is exposed to commodity price risks associated with percent of proceeds 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 is not directly dependent on commodity prices.

A variable element of the Natural Gas segment's operating income is derived from keep-whole processing of natural gas. During the first quarter of 2006, NGL prices were increasing in concert with rising crude oil prices, while natural gas prices were declining. As a result, operating income derived from our keep-whole processing for the three months ended March 31, 2006, was approximately $10.2 million compared with $4.2 million for the same period in 2005.

The operating and administrative costs and depreciation expense for our Natural Gas business were slightly higher in the first quarter of 2006 as compared to the first quarter of 2005 due to the expansion of our natural gas systems during 2005. We expect these costs to increase during the remainder of 2006 relative to the continued expansion of our systems.

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 quarter of 2006, increased drilling in the areas where our gathering systems are located has contributed to our volume growth. We expect the growth trend in these areas to continue in the future as evidenced by third-party reserve studies and the increase in rig counts in the areas served by our systems.

Late in the first quarter of 2006, we completed an 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 100 MMcf/d when we placed the plant in service in April 2005. We are continuing to make progress in constructing additional processing capacity and field compression to accommodate the volume growth the Anadarko system requires, which we expect to place in service in early 2007.

In the East Texas region, we initiated construction on several projects in the first quarter of 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, will be completed in stages throughout 2007. The new line will provide service to a number of major industrial and power companies in Southeast Texas and will cross a number of interstate pipelines.
- A 200 MMcf/d treating facility to be built near Marquez, Texas will be connected to the 36-inch pipe 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.

When fully operational in late 2007, the new assets will be 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 March 31,	
	2006	2005
	(unaudited; in millions)	
Operating revenue	$ 895.0	$ 668.0
Cost of natural gas	(874.2)	(665.7)
Operating and administrative	(1.1)	(0.8)
Depreciation and amortization	(0.1)	(0.1)
Operating expenses	(875.4)	(666.6)
Operating Income	$ 19.6	$ 1.4

Three months ended March 31, 2006 compared with three months ended March 31, 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 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 first quarter of 2006, the operating income of our Marketing segment increased $18.2 million to $19.6 million, from $1.4 million for the corresponding period in 2005. Included in operating income for the first quarter of 2006 are unrealized, non-cash, mark-to-market gains of approximately $26 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. These mark-to-market gains are primarily driven by the decline in natural gas prices since December 31, 2005. As the price of natural gas moves closer to the contract prices associated with our derivative financial instruments, the mark-to-market losses that were recorded in 2005, when natural gas prices were increasing, are reduced producing unrealized, non-cash mark-to-market gains in the current period. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled (refer also to the discussion included below under Derivative Activities, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Partially offsetting the mark-to-market gains is a non-cash loss of $8.0 million attributable to reducing the cost basis of our natural gas inventory to fair market value. Generally, we accumulate natural gas inventory during the summer months for withdrawal during late fall through early spring. During the time we were accumulating natural gas for our storage inventory, natural gas prices increased significantly as a result of supply disruptions in the Gulf of Mexico caused by hurricanes Katrina and Rita, in addition to other market factors. As a result of the increase in natural gas prices, the weighted average cost of our natural gas inventory at December 31, 2005 also increased. Natural gas prices as published by Gas Daily for Henry Hub were approximately $10.08 per million British thermal units, or MMBtu, at December 31, 2005, which had declined to $6.99 per MMBtu at March 31, 2006. As a result of the decline in the price of natural gas from December 31, 2005 to March 31, 2006, the weighted average cost of our natural gas inventory at March 31, 2006, exceeded the market price of natural gas by approximately $8.0 million. As a result of this decline, we reduced the cost basis of our inventory to fair market value at March 31, 2006 by recording a non-cash charge for $8.0 million. Due to our hedging structures, we expect that a majority of this loss will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

Corporate

Interest expense was $27.9 million for the three months ended March 31, 2006, compared with $25.6 million for the corresponding period in 2005. The increase is the result of modestly higher debt balances, less interest capitalized on construction projects and slightly higher weighted average interest rates of approximately 5.9% during the three months ended March 31, 2006, compared with approximately 5.7% during the same period in 2005.

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 facilities, 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.

During 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 Program on our Lakehead system (see Liquids segment—Future Prospects), will require significant expenditures of capital over the next several years. We expect to fund these expenditures from a balanced combination of additional issuances of 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, while funding these projects 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 that is supported by our long-term Credit Facility which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. 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 March 31, 2006, we had $440.0 million in principal amount of commercial paper outstanding and could issue an additional $160.0 million in principal amount of commercial paper.

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 March 31, 2006, no amounts had been borrowed against our Credit Facility and we had approximately $107.4 million of letters of credit outstanding. At March 31, 2006, we could borrow $452.6 million under the terms of our Credit Facility without consideration to additional borrowings under our commercial paper program.

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 $98.7 million, including $7.9 million on core maintenance activities, during the three months ended March 31, 2006.

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

System enhancements	$ 390
Core maintenance activities	55
Southern Access expansion	300
East Texas expansion	365
	$1,110

We continue to expect ongoing capital expenditures to be significant over the next three years due to the East Texas expansion and Southern Access projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper, 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.

The Southern Access and East Texas expansion projects have strong support from our customers, and upon completion each project will have stable cash flows. We have received indications that these projects can be readily financed. We are currently in discussions with our commercial bankers to structure and implement bridge credit facilities that will be required to finance the construction. This incremental bridge credit capacity may also be used to support a temporary expansion of our commercial paper program. The bridge credit facilities will be refinanced with permanent capital at key milestone dates for each project.

As of March 31, 2006, we have contractual commitments totaling $172.2 million for materials and services related to our organic growth projects. We expect to settle these commitments during the remainder of 2006; however, we will incur additional commitments as our capital projects continue to progress.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are 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 continues to remain competitive. 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 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 purchase and sales prices of our commodities. 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 March 31, 2006 for each of the indicated calendar years:

	Notional	2006	2007	2008	2009	2010	2011	2012
				(in millions)				
Swaps								
Natural gas[1]	430,197,401	$(33.1)	$(53.3)	$(44.6)	$(33.0)	$(24.9)	$(19.9)	$(4.8)
NGL[2]	7,374,950	(19.3)	(27.5)	(7.2)	(1.1)	(1.3)	—	—
Crude[2]	1,266,229	(7.5)	(10.0)	(7.0)	(1.9)	(0.5)	—	—
Options—calls								
Natural gas[1]	2,101,000	(1.0)	(1.8)	(1.6)	(1.3)	(1.1)	(0.9)	—
Options—puts								
Natural gas[1]	2,101,000	—	—	—	—	—	0.1	—
Totals		$(60.9)	$(92.6)	$(60.4)	$(37.3)	$(27.8)	$(20.7)	$(4.8)

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

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

Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2006 was $96.4 million, an increase of $7.1 million over the $89.3 million 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, as well as the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $140.2 million less in our investing activities during the three months ended March 31, 2006 in relation to the same period in 2005. The decrease is primarily attributable to the $164.6 million we spent in January 2005 for the acquisition of the gathering and processing assets in north Texas, partially offset by the approximate $26 million increase in our investments in property, plant and equipment during the first quarter of 2006 over the amount spent during the same period of 2005. The increase in our capital expenditures in the first quarter of 2006 is directly attributable to our previously announced expansion projects.

Financing Activities

Net cash provided by financing activities during the three months ended March 31, 2006 was $53.4 million, compared with $146.9 million for the corresponding period in 2005. In the first quarter of 2006 we did not issue any additional units, whereas in the first quarter of 2005 we raised $127.5 million from unit issuances. Additionally, during the first quarter of 2006 we had net commercial paper issuances of $110 million, which include gross issuances of $860 million and gross repayments of $750 million. During the first quarter of 2005, we borrowed $70 million, net of repayments, under the terms of our credit facility, including borrowings and repayments of $360 million representing net non-cash settlements with the parties to our credit facilities. Distributions to our partners were higher in the first quarter of 2006 due to an increase in the weighted average number of units outstanding 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 Declaration

On April 27, 2006, Enbridge Management's Board of Directors declared a distribution payable on May 15, 2006. The distribution will be paid to unitholders of record as of May 5, 2006, of our available cash of $67.9 million at March 31, 2006, or $0.925 per common unit. Of this distribution, $56.7 million will be paid in cash, $11.0 million will be distributed in i-units to our i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

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.

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, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and 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 purchase and sales prices of the commodities. 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 tables provide information about our derivative financial instruments at March 31, 2006 and December 31, 2005, with respect to our commodity price risk management activities for natural gas and NGLs, including crude:

	At March 31, 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	104,298,742	$ 7.26	$ 7.03	$46.6	$(23.3)	$380.6	$ (11.7)
Receive fixed/pay variable	Natural gas	104,681,622	6.98	7.51	28.4	(82.8)	14.5	(467.8)
	NGL	3,134,577	33.94	40.26	0.7	(20.0)	—	(29.7)
	Crude oil	307,475	44.32	68.99	—	(7.5)	0.2	(7.8)
Receive variable/pay variable	Natural gas	19,834,196	6.96	7.06	2.0	(4.0)	5.2	(5.2)
Options								
Calls (written)	Natural gas	275,000	8.04	4.31	—	(1.0)	—	(2.0)
Puts	Natural gas	275,000	8.04	3.40	—	—	—	—

	At March 31, 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 2007								
Swaps								
Receive variable/pay fixed	Natural gas	55,195,237	8.87	7.45	80.5	(6.8)	112.0	(1.0)
Receive fixed/pay variable	Natural gas	63,194,865	7.26	9.41	7.1	(134.7)	0.5	(170.0)
	NGL	2,698,810	28.06	37.80	—	(27.5)	—	(22.5)
	Crude oil	388,680	42.05	69.66	—	(10.0)	—	(7.9)
Receive variable/pay variable	Natural gas	7,594,666	9.32	9.23	1.3	(0.7)	0.7	(0.1)
Options								
Calls (written)	Natural gas	365,000	9.60	4.31	—	(1.8)	—	(2.0)
Puts	Natural gas	365,000	9.60	3.40	—	—	—	—
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	10,968,065	8.94	6.98	19.4	(0.1)	18.5	—
Receive fixed/pay variable	Natural gas	22,654,508	6.09	9.27	0.2	(64.7)	—	(66.3)
	NGL	729,438	25.59	36.62	—	(7.2)	—	(7.2)
	Crude oil	323,699	44.18	68.61	—	(7.0)	—	(5.2)
Receive variable/pay variable	Natural gas	4,204,000	9.08	8.92	0.6	—	1.0	—
Options								
Calls (written)	Natural gas	366,000	9.12	4.31	—	(1.6)	—	(1.7)
Puts	Natural gas	366,000	9.12	3.40	—	—	—	—
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural gas	730,000	8.44	3.57	3.0	—	—	—
Receive fixed/pay variable	Natural gas	12,227,500	4.93	8.44	—	(36.3)	—	(34.5)
	NGL	494,575	32.83	54.01	—	(1.1)	—	(0.6)
	Crude oil	155,125	53.13	67.55	—	(1.9)	—	(1.0)
Receive variable/pay variable	Natural gas	4,197,500	8.02	7.92	0.3	—	1.1	—
Options								
Calls (written)	Natural gas	365,000	8.44	4.31	—	(1.3)	—	(1.4)
Puts	Natural gas	365,000	8.44	3.40	—	—	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural gas	730,000	7.79	3.57	2.5	—	—	—
Receive fixed/pay variable	Natural gas	9,490,000	4.11	7.70	0.1	(27.5)	0.1	(25.9)
	NGL	317,550	30.60	35.51	—	(1.3)	—	(0.4)
	Crude oil	91,250	59.00	66.54	—	(0.5)	—	(0.1)
Options								
Calls (written)	Natural gas	365,000	7.79	4.31	—	(1.1)	—	(1.1)
Puts	Natural gas	365,000	7.79	3.40	—	—	—	—
Contracts maturing after 2010								
Swaps								
Receive variable/pay fixed	Natural gas	850,000	7.47	3.57	2.5	—	—	—
Receive fixed/pay variable	Natural gas	9,346,500	3.62	7.46	—	(27.2)	—	(26.1)
Options								
Calls (written)	Natural gas	365,000	7.25	4.31	—	(0.9)	—	(0.9)
Puts	Natural gas	365,000	7.25	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 March 31, 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 to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge or is not designated as a hedge, a change in the fair market value, both realized and unrealized, is recognized currently in our income statement as a derivative fair value gain (loss) and recorded in Cost of natural gas. 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, a derivative contract is settled when the future physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Accumulated other comprehensive income ("OCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. 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. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the non-cash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting, 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 three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these financial instruments are considered 'non-qualified' under SFAS No. 133. These non-qualified derivative financial instruments must be adjusted to their 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. 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 an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. **Transportation—**In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.
2. **Storage—**In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast.

This can occur as we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation established at the inception of the hedge.

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 hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices, which was a sound economic hedging strategy. 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 now accounted for in the Consolidated Statements of Income through mark-to-market accounting, 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.

In each of the three instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the financial side of the transaction is recorded at fair market values while the physical side of the transaction is not) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas 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 March 31, 2006	Three months ended March 31, 2005
	(in millions)	
Natural Gas segment		
Ineffectiveness	$ —	$(0.2)
Non-qualified hedges	1.8	(8.2)
Marketing		
Non-qualified hedges	25.9	1.4
Derivative fair value gains (losses)	$27.7	$(7.0)

We record the change in fair value of our highly effective cash flow hedges in OCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in OCI are unrecognized losses of approximately $7.1 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These unrecognized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three months ended March 31, 2006, we reclassified unrealized losses of $24.8 million 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:

	March 31, 2006	December 31, 2005
	(in millions)	
Other current assets	$ 0.8	$ 5.8
Other assets, net	6.4	4.2
Accounts payable and other	(87.9)	(129.2)
Other long-term liabilities	(217.4)	(243.0)
	$(298.1)	$(362.2)

The decrease in our obligation associated with derivative activities from December 31, 2005 to March 31, 2006 is primarily due to the significant decreases in current and forward natural gas prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price 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 March 31, 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 three months ended March 31, 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 restricts 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).

4.1 Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).

31.1* Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1* Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2* Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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: April 28, 2006

By: /s/ DAN C. TUTCHER
Dan C. Tutcher
President
(Principal Executive Officer)

Date: April 28, 2006

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