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, 2007

OR

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

For the transition period from to

Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, 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 30, 2007.

ENBRIDGE ENERGY PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

In this report, unless the context requires otherwise, references to "we", "us", "our", or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "would," or "will" or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Risk Factors" included in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006 and in Part II, Item 1A of our quarterly reports on Form 10-Q.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three months ended March 31,	
	2007	2006
	(unaudited; in millions, except per unit amounts)	
Operating revenue	$1,712.7	$1,888.6
Operating expenses		
Cost of natural gas (Note 10)	1,484.3	1,647.7
Operating and administrative	97.7	73.9
Power	30.1	26.3
Depreciation and amortization	36.5	32.7
	1,648.6	1,780.6
Operating income	64.1	108.0
Interest expense	25.3	27.9
Other income	1.4	1.0
Income before income tax expense	40.2	81.1
Income tax expense (Note 6)	1.1	—
Net income	$ 39.1	$ 81.1
Net income allocable to limited partner units (Note 2)	$ 31.4	$ 73.9
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.40	$ 1.12
Weighted average units outstanding	77.8	65.7

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,	
	2007	2006
	(unaudited; in millions)	
Net income	$ 39.1	$ 81.1
Other comprehensive income (loss) (Note 10)	(40.3)	34.1
Comprehensive income (loss)	$ (1.2)	$115.2

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, 2007	2006
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 39.1	$ 81.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	36.5	32.7
Derivative fair value (gains) losses (Note 10)	16.3	(27.7)
Inventory market price adjustments (Note 4)	—	8.0
Environmental liabilities (Note 9)	(0.6)	(0.2)
Other	(0.8)	(1.1)
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	45.5	(15.7)
Due from General Partner and affiliates	(13.2)	(1.3)
Accrued receivables	28.2	105.5
Inventory (Note 4)	61.1	26.7
Current and long-term other assets (Note 10)	(0.2)	(0.5)
Due to General Partner and affiliates	(3.3)	1.9
Accounts payable and other (Notes 3 and 10)	(28.9)	(36.6)
Accrued purchases	(53.1)	(101.7)
Interest payable	23.5	19.9
Current income tax payable (Note 6)	1.1	—
Property and other taxes payable	1.6	5.4
Net cash provided by operating activities	152.8	96.4
Cash used in investing activities		
Additions to property, plant and equipment	(399.3)	(98.7)
Changes in construction payables	63.9	(6.8)
Other	0.4	(0.3)
Net cash used in investing activities	(335.0)	(105.8)
Cash provided by financing activities		
Distributions to partners (Note 8)	(57.6)	(56.6)
Net issuances of commercial paper (Note 7)	139.4	110.0
Net cash provided by financing activities	81.8	53.4
Net increase (decrease) in cash and cash equivalents	(100.4)	44.0
Cash and cash equivalents at beginning of year	184.6	89.8
Cash and cash equivalents at end of period	$ 84.2	$ 133.8

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2007	December 31, 2006
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 84.2	$ 184.6
Receivables, trade and other, net of allowance for doubtful accounts of $1.7 in 2007 and $2.4 in 2006	101.8	146.7
Due from General Partner and affiliates	43.7	30.5
Accrued receivables	488.3	516.5
Inventory (Note 4)	56.0	117.1
Other current assets (Note 10)	8.2	13.9
	782.2	1,009.3
Property, plant and equipment, net (Note 5)	4,188.5	3,824.9
Other assets, net (Notes 6 and 10)	32.2	32.5
Goodwill	265.7	265.7
Intangibles, net	90.3	91.4
	$5,358.9	$5,223.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 19.3	$ 22.6
Accounts payable and other (Notes 3 and 10)	276.3	211.5
Accrued purchases	477.2	530.3
Interest payable	32.6	11.4
Property and other taxes payable (Note 6)	20.9	18.6
Loans from General Partner and affiliates	138.5	136.2
Current maturities of long-term debt	31.0	31.0
	995.8	961.6
Long-term debt (Note 7)	2,203.8	2,066.1
Environmental liabilities (Note 9)	4.1	3.3
Other long-term liabilities (Note 10)	170.6	149.4
	3,374.3	3,180.4
Commitments and contingencies (Note 9)		
Partners' capital (Note 8)		
Class A common units (Units issued—49,938,834 in 2007 and 2006)	1,115.5	1,141.7
Class B common units (Units issued—3,912,750 in 2007 and 2006)	65.7	67.6
Class C units (Units issued—11,265,872 in 2007 and 11,070,152 in 2006)	514.3	509.8
i-units (Units issued—12,902,676 in 2007 and 12,674,148 in 2006)	471.5	466.3
General Partner	47.5	47.6
Accumulated other comprehensive loss (Note 10)	(229.9)	(189.6)
	1,984.6	2,043.4
	$5,358.9	$5,223.8

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

ENBRIDGE ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

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, 2007 and December 31, 2006, the results of operations, comprehensive income and cash flows for the three month periods ended March 31, 2007 and 2006. We derived the consolidated statement of financial position as of December 31, 2006, from the audited financial statements included in our 2006 Annual Report on Form 10-K. The results of operations for the three month period ended March 31, 2007, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the natural gas business, timing and completion of our construction projects, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. In addition, our consolidated statements of cash flows for the period ended March 31, 2006 include reclassifications that were made to present changes in environmental liabilities separately from changes in Accounts payable and other, consistent with our current period presentation. These reclassifications have no effect on previously reported results of operations, comprehensive 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, 2006.

2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after deduction of Enbridge Energy Company, Inc.'s (the "General Partner") allocation, by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. We have no dilutive securities. Net income per limited partner unit was determined as follows:

	Three months ended March 31,	
	2007	2006
	(in millions, except per unit amounts)	
Net income	$39.1	$81.1
Allocations to the General Partner:		
Net income allocated to the General Partner	(0.8)	(1.6)
Incentive income allocated to the General Partner	(6.8)	(5.6)
Historical cost depreciation adjustments	(0.1)	—
	(7.7)	(7.2)
Net income allocable to limited partner units	$31.4	$73.9
Weighted average units outstanding	77.8	65.7
Net income per limited partner unit (basic and diluted)	$0.40	$1.12

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $28.5 million at March 31, 2007 and $46.9 million at December 31, 2006, are included in Accounts payable and other on the Consolidated Statements of Financial Position.

4. INVENTORY

Inventory is comprised of the following:

	March 31, 2007	December 31, 2006
	(in millions)	
Material and supplies	$ 3.9	$ 3.8
Liquids inventory	4.9	9.9
Natural gas and natural gas liquids inventory	47.2	103.4
	$56.0	$117.1

5. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	March 31, 2007	December 31, 2006
	(in millions)	
Land	$ 14.8	$ 14.3
Rights-of-way	306.2	298.6
Pipelines	2,367.8	2,320.8
Pumping equipment, buildings and tanks	765.5	747.4
Compressors, meters, and other operating equipment	436.9	418.1
Vehicles, office furniture and equipment	116.8	112.4
Processing and treating plants	87.2	86.4
Construction in progress	1,036.0	733.6
Total property, plant and equipment	5,131.2	4,731.6
Accumulated depreciation	(942.7)	(906.7)
Net property, plant and equipment	$4,188.5	$3,824.9

6. INCOME TAXES

We are not a taxable entity for U.S. federal income tax purposes, or for the majority of states that impose income tax. The taxes on our net income are generally borne by our unitholders through the allocation of taxable income. In May 2006, the State of Texas enacted substantial changes to its tax structure to impose a new tax based on modified gross margin, which began in 2007. Under the provisions of Statement of Financial Accounting Standards (“SFAS”) No. 109, *Accounting for Income Taxes*, we have determined that this tax is an income tax. Our income tax expense is $1.1 million for the three months ended March 31, 2007, which we computed by applying a 0.56% apportioned state income tax rate to taxable margin, as defined in State of Texas statutes. Our income tax expense represents a 2.7% effective rate as applied to pretax book income. At March 31, 2007, we have included a current income tax payable of $1.1 million in Property and other taxes payable and a deferred income tax asset of $0.5 million in Other assets, net on our Consolidated Statement of Financial Position.

7. DEBT

Credit Facility

At March 31, 2007 and December 31, 2006, we had no amounts outstanding under our Credit Facility and had letters of credit totaling $73.0 million and $59.3 million, respectively. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At March 31, 2007, we could borrow $345.0 million under the terms of our Credit Facility without consideration to additional borrowings under our commercial paper program.

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

Commercial Paper Program

Under the terms of our commercial paper program, we can issue up to $600 million of commercial paper. At March 31, 2007, we had outstanding $581.4 million of commercial paper, net of unamortized discount of $0.6 million, bearing interest at a weighted average rate of 5.45%. At December 31, 2006, we had $443.7 million of commercial paper outstanding, net of $1.3 million of unamortized discount, at a weighted average interest rate of 5.45%. At March 31, 2007, we could issue an additional $18 million in principal amount under the terms of our commercial paper program.

8. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") during the three months ended March 31, 2007:

Distribution Declaration Date	Distribution Payment Date	Record Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders(1)	Amount of Distribution of Class C units to Class C unit Holders(2)	Retained from General Partner(3)	Distribution of Cash
January 26, 2007	February 14, 2007	February 6, 2007	$0.925	$80.0	$11.7	$10.2	$0.5	$57.6

(1) During 2007, in lieu of cash distributions, the Partnership issued 228,528 i-units to Enbridge Management.

(2) During 2007, in lieu of cash distributions, the Partnership issued 195,720 Class C units to our Class C unitholders.

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

Private Placement of Class C Units

During April 2007, we issued and sold 4.7 million Class C units at a price of $53.11 per Class C unit to CDP Infrastructure Fund G.P. ("CDP"), 0.9 million Class C units to Tortoise Infrastructure Corporation and 0.3 million Class C units to Tortoise Energy Capital Corporation. We sold the Class C units in a private transaction exempt from registration under Section 4(2) of the Securities Act. We received net proceeds, including expenses associated with the private placement, of approximately $315 million. In addition, our general partner contributed approximately $6.4 million to us to maintain its 2.0 percent general partner interest. We intend to use the net proceeds from the sale to finance a portion of our capital expansion program, including the East Texas and Southern Access expansion projects.

9. COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact on the environment of our operations.

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

In January 2007, we detected a leak on Line 14 of our Lakehead system, near the Owen, Wisconsin pump station. We immediately shut the pipeline down and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline at an estimated cost of $1 million, which we have recorded as a liability on our Consolidated Statements of Financial Position. We estimate the spill to approximate 1,500 barrels. We completed excavation and repairs and returned the line to service within two days. We have applied pressure restrictions to the line as we work with federal and state environmental and pipeline safety regulators to investigate the cause of the rupture. Such pressure restrictions are not anticipated to have a material impact on system through-put. We have the potential of incurring additional expenditures to remediate any condition on the line that is determined to have caused the rupture.

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

Legal Proceedings

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

10. DERIVATIVE FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Accounting Treatment

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

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

If a derivative financial instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in Accumulated other comprehensive income (“AOCI”), a component of Partners’ Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge’s change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges, for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as “non-qualified.” Non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated financial instrument contract settlement is made.

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

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

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

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

4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas

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

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

The following table presents the mark-to-market gains and losses associated with changes in the fair value of our commodity price derivative financial instruments, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended March 31, 2007	2006
	(in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ 0.1	$ —
Non-qualified hedges	(3.2)	1.8
Marketing		
Non-qualified hedges	(13.2)	25.9
Derivative fair value gains (losses)	$(16.3)	$27.7

We record the change in fair value of our cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified from AOCI to earnings. Also included in AOCI are unrecognized losses of approximately $4.1 million associated with cash flow hedges that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three months ended March 31, 2007, we reclassified losses of $16.2 million, respectively from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

Derivative Positions

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

	March 31, 2007	December 31, 2006
	(in millions)	
Other current assets	$ 1.7	$ 7.2
Other assets, net	10.6	11.0
Accounts payable and other	(88.1)	(57.2)
Other long-term liabilities	(160.3)	(136.4)
	$(236.1)	$(175.4)

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

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

11. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present certain financial information about our business segments:

	As of and for the three months ended March 31, 2007				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 132.8	$1,324.3	$889.4	$ —	$2,346.5
Less: Intersegment revenue	—	568.8	65.0	—	633.8
Operating revenue	132.8	755.5	824.4	—	1,712.7
Cost of natural gas	—	663.2	821.1	—	1,484.3
Operating and administrative	33.7	61.3	1.6	1.1	97.7
Power	30.1	—	—	—	30.1
Depreciation and amortization	16.4	20.0	0.1	—	36.5
Operating income	52.6	11.0	1.6	(1.1)	64.1
Interest expense	—	—	—	25.3	25.3
Other income	—	—	—	1.4	1.4
Income before income tax expense	52.6	11.0	1.6	(25.0)	40.2
Income tax expense	—	—	—	1.1	1.1
Net income	$ 52.6	$ 11.0	$ 1.6	$ (26.1)	$ 39.1
Total assets	$2,016.7	$2,845.6	$334.5	$162.1	$5,358.9
Capital expenditures (excluding acquisitions)	$ 223.2	$ 166.7	$ 1.2	$ 8.2	$ 399.3

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

	As of and for the three months ended March 31, 2006				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
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	—	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 (loss)	$ 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

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

12. SUBSEQUENT EVENT

Distribution to Partners

On April 26, 2007, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2007. The distribution will be paid to unitholders of record as of May 7, 2007, of our available cash of $86.6 million at March 31, 2007, or $0.925 per common unit. Of this distribution, $58.2 million will be paid in cash, $11.9 million will be distributed in i-units to our i-unitholder, $15.9 million will be distributed in Class C units to the holders of our Class C units and $0.6 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

13. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In February 2007, the Financial Accounting Standards Board (FASB) issued Statement No. 159, *The Fair Value Option for Financial Assets and Liabilities.* This statement provides companies with an option to report certain financial assets and liabilities at fair value. The objective of SFAS No. 159 is to reduce complexity in accounting for financial instruments and the volatility in earnings caused by measuring related financial assets and liabilities. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007. We have elected not to early adopt the provisions of SFAS No. 159, although early adoption is permitted as of the beginning of a fiscal year that begins on or before November 15, 2007, provided the entity also elects to apply the provisions of SFAS No. 157. We do not expect our adoption of SFAS No. 159 to have a material affect on our Consolidated Financial Statements.

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

The following discussion and analysis of our financial condition and results of operations should be read together with our Consolidated Financial Statements and the accompanying notes included in "Item 1. Financial Statements" of this report.

Additionally, this quarterly report on Form 10-Q should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2006.

RESULTS OF OPERATIONS—OVERVIEW

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

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

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

We primarily provide fee-based services to our customers to minimize our exposure to commodity price risks. However, in our natural gas and marketing businesses, a portion of our earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure and to provide stability to our cash flow, we enter into derivative financial instrument transactions. Certain of these transactions qualify for hedge accounting under 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:

	Three months ended March 31,	
	2007	2006
	(in millions)	
Operating Income		
Liquids	$52.6	$ 51.8
Natural Gas	11.0	37.2
Marketing	1.6	19.6
Corporate, operating and administrative	(1.1)	(0.6)
Total Operating Income	64.1	108.0
Interest expense	25.3	27.9
Other income	1.4	1.0
Income tax expense	1.1	—
Net Income	$39.1	$ 81.1

Summary Analysis of Operating Results

Liquids

Our Liquids segment produced operating income of $52.6 million for the three months ended March 31, 2007, a slight increase over the $51.8 million earned in the same period of 2006. The increase in operating income of our Liquids segment is primarily due to improved operating results on our Mid-Continent system, complemented by consistent operating results on our Lakehead system.

Natural Gas

Operating income from our Natural Gas segment decreased by $26.2 million to $11.0 million for the three months ended March 31, 2007, from $37.2 million for the same period in 2006. The decrease in contribution from our Natural Gas segment is primarily attributable to the following:

- An unexpected increase in natural gas measurement losses on two of our major gathering systems, partly resulting from increased water production within some natural gas streams.
- Operational inefficiencies at our Zybach plant, in part caused by fouling of the plant by contaminated water in the natural gas stream, which reduced NGL production and the associated revenue.
- Increased operating and administrative costs associated with the increase in volumes and expansion of our natural gas systems as well as changing pipeline integrity regulation.

Marketing

Operating income from our Marketing segment decreased by $18.0 million to $1.6 million for the three months ended March 31, 2007 from $19.6 million for the same period in 2006. The decrease in operating income of our Marketing segment is predominantly the result of three factors:

- Unrealized, non-cash mark-to-market net losses for the three months ended March 31, 2007 of $13.2 million compared with non-cash mark-to-market net gains of $25.9 million for the same period in 2006, that resulted from the change in market value of our derivative financial instruments that do not qualify for hedge accounting.
- Partially offsetting our unrealized, non-cash, mark-to-market losses in the first quarter of 2007 is income of approximately $12 million that we realized upon the sale of approximately 3.9 billion cubic feet, or bcf of natural gas inventory that included approximately $6 million in gains from the settlement of derivative financial instruments hedging our natural gas inventory.
- During the three months ended March 31, 2006, we recorded a non-cash charge of $8.0 million, resulting from a lower of cost or market accounting adjustment to the cost basis of our natural gas inventory that we did not incur during the first quarter of 2007. The market price for natural gas in various storage locations may experience declines during the year from the prices at which the inventory was purchased.

Derivative Transactions and Hedging Activities

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

The unrealized, mark-to-market losses for the three months ended March 31, 2007, are the result of increases in the forward and daily market prices of natural gas and NGLs, compared to the first quarter of

2006. 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, 2007 and 2006:

Derivative fair value gains (losses)	Three months ended March 31, 2007	2006
	(in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ 0.1	$ —
Non-qualified hedges	(3.2)	1.8
Marketing		
Non-qualified hedges	(13.2)	25.9
Derivative fair value gains (losses)	$(16.3)	$27.7

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

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

	Three months ended March 31, 2007	2006
	(in millions)	
Operating Results		
Operating revenues	$132.8	$122.6
Operating and administrative	33.7	28.6
Power	30.1	26.3
Depreciation and amortization	16.4	15.9
Operating expenses	80.2	70.8
Operating Income	$ 52.6	$ 51.8
Operating Statistics		
Lakehead system:		
United States[1]	1,248	1,161
Province of Ontario[1]	335	348
Total deliveries[1]	1,583	1,509
Barrel miles (billions)	103	100
Average haul (miles)	722	738
Mid-Continent system deliveries[1]	238	237
North Dakota system deliveries[1] [2]	87	82
Total Liquids Segment Delivery Volumes[1]	1,908	1,828

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

(2) Included in these volumes for the three months ended March 31, 2007 and 2006, respectively are approximately 6,000 Bpd and 8,000 Bpd of deliveries for which we receive both gathering and transportation tolls.

Three months ended March 31, 2007 compared with three months ended March 31, 2006

Our Liquids segment accounted for $52.6 million of operating income during the three months ended March 31, 2007, representing a $0.8 million increase over the same period in 2006. The increase is primarily related to improved operating results on our Mid-Continent system coupled with consistent results on our Lakehead system.

Operating revenue for the first quarter of 2007 increased by approximately $10.2 million to $132.8 million from $122.6 million for the same period in 2006. Volumes on our Lakehead system increased approximately 5 percent, from 1.509 million Bpd during the first quarter of 2006 to 1.583 million Bpd during the same period in 2007, which resulted in higher operating revenue of approximately $4.9 million. In addition, increases in average tariffs on all three Liquids systems resulted in higher operating revenue by approximately $4.3 million. These tariff increases were the result of the annual index rate increases allowed by the Federal Energy Regulatory Commission ("FERC"). New tariff rates went into effect on April 1, 2006 for an adjustment on the Terrace expansion program surcharge and new facilities in service, which were not in effect during the first quarter of 2006. Further tariff revisions came about as a result of the annual index rate increase allowed by the FERC effective July 1, 2006.

Operating and administrative expenses for the Liquids segment increased $5.1 million for the first quarter of 2007, compared with the same period in 2006. The increase is driven primarily by (i) higher workforce related costs due to the additional costs we are charged for operational, administrative, regulatory and compliance support necessary for our existing assets, (ii) the expansion of our liquids operations and (iii) repairs and cleanup costs associated with the leak on line 14 that occurred in January 2007.

Power costs increased $3.8 million in the first quarter of 2007, compared with the same period in 2006, primarily due to the increased throughput on our Lakehead system, along with higher utility rates we are charged by our power suppliers.

Future Prospects Update for Liquids

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

<u>Partnership Projects</u>

Southern Access

In conjunction with Enbridge, we announced in 2005 the approval of the 400,000 Bpd Southern Access expansion project, which received endorsement from the Canadian Association of Petroleum Producers, or CAPP, a trade association that represents a large majority of the Lakehead system's customers. We are undertaking the U.S. portion of the expansion on our Lakehead system. The first stage will add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. The project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in early 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system. In April 2007, the Illinois Commerce Commission approved and allowed the project to exercise the right of eminent domain if necessary. We continue to progress on schedule with this project; however, we are experiencing cost pressures for labor, materials and rights-of-way which may affect the ultimate cost of completing this project. The risk to our unitholders resulting from these cost pressures is largely mitigated by the cost of service tolling arrangement used for this project.

Alberta Clipper

Based on forecasts of oil sands production growth prepared by Enbridge, as well as forecasts by CAPP, we believe that there will be a need for additional export pipeline capacity out of Western Canada over and above projects which have already received shipper support. Based on this analysis, as well as interest expressed by shippers, we and Enbridge are planning to develop the Alberta Clipper project. This project will involve construction of a 36-inch diameter heavy crude line from Hardisty, Alberta to Superior, Wisconsin in conjunction with additional pumping power applied to the Southern Access 42-inch pipe from Superior to Flanagan, Wisconsin. We anticipate that our share of the cost of this project, as currently proposed, will approximate $0.8 billion in 2006 dollars.

Alberta Clipper was originally planned to be a contract carrier pipeline based on interest expressed by selected shippers in providing throughput commitments in return for assured access to capacity. Based on discussions with a broader group of shippers the preference is for Alberta Clipper to be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. Enbridge is continuing to finalize commercial terms of the Alberta Clipper project with CAPP. To maintain the project construction schedule, CAPP has agreed to backstop initial capital costs of the Alberta Clipper project. Initial capital costs will include long-lead time items such as pipe, pumping equipment and rights of way. In the unlikely event the Alberta Clipper project does not proceed, CAPP will support the collection of the initial capital costs through our normal FERC rate setting process. Alberta Clipper is expected to be in service between late 2009 and mid-2010. The project progressed through the first quarter of 2007 as anticipated.

North Dakota

Work continues on our previously announced North Dakota system expansion. North Dakota Public Service Commission approvals were obtained for all phases of the project during 2006. The expansion will add approximately 30,000 Bpd of mainline throughput capacity and expand the system's feeder segment by approximately 30,000 Bpd at an estimated cost $0.1 billion. 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 phases throughout 2007, with the final completion scheduled for the fourth quarter of 2007. As shippers continue to express interest in further expansion of pipeline capacity, we initiated an open season to enlist shipper commitments for further expansion of the North Dakota system.

Superior and Griffith Storage

Due to forecasted production increases of synthetic heavy crude oil that we anticipate will be transported on the Enbridge/Lakehead mainline systems from Western Canada to Chicago, we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We are building two tanks with an approximate capacity of 360,000 barrels each that are scheduled for completion in the first half of 2007 and two additional tanks each with an approximate capacity of 250,000 barrels each to be completed in the first half of 2008.

Cushing Terminal Storage

We continue to experience strong interest from customers in securing access to long-term contract storage capacity at our Cushing, Oklahoma terminal. During 2006, we obtained commitments and initiated construction of an additional 5.0 million barrels of storage tanks, 1.1 million barrels of which were completed in late December 2006. The remaining 3.9 million barrels of capacity will be completed during 2007 at an expected cost of $72 million. Once complete our total terminal capacity will be approximately 16.7 million barrels, which includes 1.4 million barrels of operational storage. This capacity will increase operational tankage available to support our Mid-Continent liquids pipeline systems, and available contract storage. Progress continues to be made in adding additional capacity to the terminal.

Enbridge and Other Projects

Spearhead Reversal

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

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and CAPP for its 36-inch diameter Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project is scheduled for completion in the first quarter of 2009 and will be undertaken by Enbridge; however, we will benefit through incremental volumes moving through our Lakehead system to reach this extension. The Offer of Settlement filed in September 2006 was rejected by the FERC because of its rolled-in toll design. However, support for the project remains high and Enbridge is working with shippers to prepare an alternative tolling structure to address the initial opposition. The second application is expected to be filed with the FERC in the near future and should allow the project to proceed on schedule.

Southern Lights

During the third quarter of 2006, Enbridge completed a successful open season on its Southern Lights diluent pipeline from Chicago, Illinois to Edmonton, Alberta. The Southern Lights pipeline responds to the need to increase the availability of crude oil diluent in Alberta. Diluent is required to transport the heavy oil and bitumen being produced in increasing volumes from the Alberta oil sands. The project involves the exchange of a 156-mile section of pipeline we own for a similar section of a new pipeline to be constructed as part of the project. We expect to benefit from increased heavy crude shipments, which will be facilitated by the diluent line. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us. This project is expected to be in service during 2010. During the first quarter of 2007 Enbridge filed applications with Canada's National Energy Board (NEB) for approval of all facets of the Canadian portion of the project and continues to progress on the necessary applications for the U.S. portion of the project with U.S. federal and state regulatory agencies. In conjunction with the Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right of way in Illinois.

U.S. Gulf Coast Access

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

Eastern PADD II Access

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

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

Natural Gas

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

	Three months ended March 31,	
	2007	**2006**
	(in millions)	
Operating Results		
Operating revenues	$ 755.5	$ 871.0
Cost of natural gas	663.2	773.5
Operating and administrative	61.3	43.7
Depreciation and amortization	20.0	16.6
Operating expenses	744.5	833.8
Operating Income	$ 11.0	$ 37.2
Operating Statistics (MMBtu/d)		
East Texas	1,135,000	921,000
Anadarko	583,000	563,000
North Texas	320,000	279,000
UTOS	125,000	199,000
MidLa	110,000	83,000
AlaTenn	59,000	54,000
KPC	37,000	47,000
Bamagas	115,000	37,000
Other major intrastates(1)	267,000	220,000
Total	2,751,000	2,403,000

(1) We have included in Other major intrastates the volumes of our Gloria system for the three months ended March 31, 2007 and 2006 in the amounts of 66,000 MMBtu/d and 62,000 MMBtu/d, respectively.

Three months ended March 31, 2007 compared with three months ended March 31, 2006

Our Natural Gas segment contributed $11.0 million of operating income in the first quarter of 2007, a decrease of $26.2 million from the $37.2 million contributed in the corresponding period of 2006. Although the overall volumes for the first quarter of 2007 on our three largest systems were greater than the comparable period of 2006, operational inefficiencies at our Zybach plant and an unexpected increase in measurement losses, primarily on our East Texas and Anadarko systems, reduced the operating income of our Natural Gas segment. Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather temperatures and variances in measurement that are inherent in metering technologies. We are taking steps to address these operational issues through plant maintenance and discussions with producers that use our natural gas systems.

We have identified operating conditions on our gathering systems which we believe have contributed to our increased measurement losses. We are taking several actions to address increased measurement losses. These steps include the installation of separator equipment to identify free-water in the natural gas streams and shut in such streams until producers are able to eliminate the free-water. During the first quarter of 2007 we estimate that measurement losses resulted in approximately $8 million of additional economic cost to our natural gas systems relative to the first quarter of 2006.

Average daily volumes on our major natural gas systems were up approximately 14 percent in the first quarter of 2007, compared with the corresponding period in 2006. Increases in our volumes for 2007 are attributable to our ongoing investments to expand the capacity of our systems and services. Our investments in the following projects that were completed during 2006 and 2007 contributed to the increase in the average daily volumes and operating results on our major natural gas systems:

- The link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005;
- Construction of our 120 MMcf/d Henderson natural gas processing facility on our East Texas system was completed at the end of the third quarter of 2006 and processed volumes of approximately 100 MMcf/d; and
- Acquisition of an 80-mile pipeline in April 2006 that is complementary to our existing East Texas system that provided approximately 75,000 MMBtu/d of incremental volume.

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

A variable element of our Natural Gas segment's operating income is derived from keep-whole processing of natural gas. Operating income derived from our keep-whole processing for the three months ended March 31, 2007, was approximately $5 million, compared with approximately $10 million for the same period in 2006. As a result of operational issues associated with our Zybach processing plant the revenue generated by our processing assets less the cost of natural gas purchased for processing was approximately $8 million lower than the amounts we realized in the comparable period of 2006.

During the first quarter of 2007, we determined that our Zybach processing plant needed to be repaired and modified. We are undertaking a project to increase the plant's NGL recoveries, which have decreased in the first quarter of 2007 compared to its level of production when we initially commissioned the plant in 2006. The operating inefficiencies created by this condition negatively affected our processing results in the first quarter of 2007. As a result of this condition, we are completing modifications to enhance recoveries of NGLs at our Zybach plant.

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

Operating income of our Natural Gas segment for the first quarter of 2007 includes unrealized non-cash, mark-to-market net losses of $3.1 million, including $0.1 million of gains resulting from ineffectiveness of our cash flow hedges and $3.2 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. In the first quarter of 2006, our operating income was increased by $1.8 million of unrealized, non-cash, mark-to-market net gains that we incurred, primarily from derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled (refer also to the discussions included in Note 10 of Item 1. Financial Statements and following under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Operating and administrative costs of our Natural Gas segment were $17.6 million greater for the three months ended March 31, 2007 than the three months ended March 31, 2006, primarily as a result of increased workforce related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. However, the operating costs in the first quarter of 2007 approximate our operating costs for the fourth quarter of 2006. This is consistent with the expansion of our natural gas systems and the related costs that continue to increase as we expand our systems and increase the volumes of natural gas services we provide. Workforce related costs have increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of continuous pipeline expansions across the areas we serve.

Materials, supplies and other costs along with repair and maintenance costs were higher predominantly related to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. During the first quarter of 2007, we spent more on pipeline integrity work in connection with our ongoing pipeline integrity management program compared with the same period of

2006. We expect workforce related costs in addition to materials, supplies and other cost to continue increasing as we expand our systems and increase the volumes of natural gas services we provide.

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

Future Prospects Update for Natural Gas

We continue to assess various expansion opportunities to pursue our strategy for growth. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. We may, and have, pursued opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During the first quarter of 2007, 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 external production forecast and the strong rig counts and permitting in the areas served by our systems.

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

East Texas System Expansion and Extension (Project Clarity):

- The expansion and extension of our East Texas natural gas system, referred to as the Clarity project, includes construction of a 36-inch diameter intrastate pipeline from Bethel, Texas to Orange County, Texas with capacity of approximately 700 MMcf/d. The new pipeline will provide service to a number of major industrial companies in Southeast Texas and will cross a number of interstate pipelines. We continue to secure additional commitments for capacity on the pipeline. We currently anticipate the expansion project will cost approximately $610 million; however, we are experiencing cost pressures for labor, materials and rights-of-way, which may affect the ultimate cost of completing the construction of this project. Additionally, the project's schedule could be affected by severe weather conditions.
- The first phase of our Clarity project was completed late in March 2007 and includes the construction of a 24-inch diameter intrastate pipeline that extends approximately 60 miles from Marquez, Texas to Crockett, Texas and a 36-inch diameter pipeline that extends approximately 53 miles from Crockett to Goodrich, Texas. We expect the completion of this phase to begin to contribute modest operating revenue to our natural gas segment in the second quarter of 2007 following completion of upstream gathering facilities late in the second quarter.
- The remainder of our Clarity project is expected to be completed in stages throughout 2007. These phases include the construction of a 36-inch diameter intrastate pipeline that extends approximately 63 miles from Bethel to Crockett and approximately 42 miles from Goodrich to Kountze, Texas and approximately 41 miles from Kountze to Orange County.

- As part of our East Texas expansion project we added a 200 MMcf/d treating facility near Marquez which is connected to the 36-inch diameter intrastate pipeline via a new 24-inch diameter pipeline. This project was completed in conjunction with the first phase of our Clarity project in late March 2007, and is expected to contribute additional volume growth on our East Texas natural gas system through increased CO_2 and sour gas treating capacity commensurate with the completion of several ongoing construction projects in the area.

Other East Texas Projects:

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

North Texas System Projects:

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

Anadarko System Projects:

- Our Anadarko system continues to experience considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. We are continuing to make progress in increasing processing capacity and field compression in the region and expect to place 155 MMcf/d of additional processing capacity as well as field compression in service during May 2007.
- During the second quarter of 2007, we refurbished our Zybach processing plant to address the operational inefficiencies being experienced by the plant. As a result of the downtime and associated restart we expect processing volumes and operating revenues from our Anadarko system to continue to be depressed in the second quarter.

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

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

Other Matters

In December 2005, Calpine Corporation ("Calpine") and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Calpine has continued to perform under the terms of its agreement with Bamagas 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,	
	2007	**2006**
	(in millions)	
Operating revenues	$824.4	$895.0
Cost of natural gas	821.1	874.2
Operating and administrative	1.6	1.1
Depreciation and amortization	0.1	0.1
Operating Expenses	822.8	875.4
Operating Income	$ 1.6	$ 19.6

Three months ended March 31, 2007 compared with three months ended March 31, 2006

In the first quarter of 2007, the operating income of our Marketing segment decreased $18.0 million to $1.6 million, from $19.6 million for the corresponding period in 2006. Included in operating income for the first quarter of 2007 are unrealized, non-cash, mark-to-market losses of approximately $13.2 million compared with unrealized mark-to-market gains of $25.9 million for the comparable period in 2006, associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The unrealized, mark-to-market losses for the three months ended March 31, 2007, are the result of increases in the forward and daily market prices of natural gas and NGLs from December 31, 2006. We expect these net mark-to-market losses to be offset when the related physical transactions are settled (refer also to the discussion included in Note 10 of Item 1. Financial Statements, following under Derivative Activities and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

The operating results of our Marketing business for the three months ended March 31, 2007, do not include adjustments to the cost basis of our natural gas inventory to reduce it to fair market value. Natural gas prices as published by Platt's *Gas Daily* for Henry Hub were approximately $7.34 per MMBtu at March 31, 2007, which had increased from $5.64 per MMBtu at December 31, 2006. Partially offsetting our unrealized, non-cash, mark-to-market losses in the first quarter of 2007 are gains of approximately $12 million that we realized upon the sale of approximately 3.9 Bcf of natural gas inventory that included approximately $6 million in gains from the settlement of derivative financial instruments hedging our natural gas inventory.

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

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

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

Corporate

Interest expense was $25.3 million for the three months ended March 31, 2007, compared with $27.9 million for the corresponding period in 2006. The decrease is primarily the result of $8.5 million of interest capitalized on our construction projects for the three months ended March 31, 2007, compared with the $0.5 million capitalized during the same period of 2006. Partially offsetting the increase in capitalized interest is the additional interest expense generated by higher weighted average debt balances. Our weighted average interest rate of 5.9% is consistent with our weighted average interest rate of 5.9% for the same period in 2006.

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Our income tax expense of $1.1 million for the three months ended March 31, 2007 results from the enactment, by the State of Texas, of a new state tax computed on our 2007 modified gross margin. We determined this tax to be an income tax under the provisions of SFAS No. 109, *Accounting for Income Taxes*. We computed our income tax expense for the quarter ended March 31, 2007 by applying a

0.56% apportioned state income tax rate to taxable margin, as defined in State of Texas statutes. Our income tax expense represents a 2.7% effective rate as applied to pretax book income.

LIQUIDITY AND CAPITAL RESOURCES

General

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

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. The internal growth projects we have planned for our Natural Gas business (see Natural Gas segment—Future Prospects), coupled with the Southern Access and Alberta Clipper projects on our Lakehead system (see Liquids segment—Future Prospects), will require significant expenditures of capital over the next several years. We expect to fund these expenditures from a balanced combination of additional issuances of 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. During our construction of these major projects, our ability to increase distributions while funding these construction costs is likely to be limited.

Capital Resources

Equity Capital

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity markets to obtain the capital necessary to fund these projects. During April 2007, we issued and sold 4.7 million Class C units at a price of $53.11 per Class C unit to CDP Infrastructure Fund G.P. ("CDP"), 0.9 million Class C units to Tortoise Infrastructure Corporation and 0.3 million Class C units to Tortoise Energy Capital Corporation. We sold the Class C units in a private transaction exempt from registration under Section 4(2) of the Securities Act. We received net proceeds, including expenses associated with the private placement, of approximately $315 million. In addition, our general partner contributed approximately $6.4 million to us to maintain its 2.0 percent general partner interest. We intend to use the net proceeds from the sale to finance a portion of our capital expansion program, including the East Texas and Southern Access expansion projects.

Available Credit

A significant source of our liquidity is provided by the commercial paper market and our Credit Facility. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility.

Credit Facility

The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At March 31, 2007, no amounts had been borrowed against our Credit Facility and we had approximately $73.0 million of letters of credit outstanding. At March 31, 2007, we could borrow $345 million under the terms of our Credit Facility without consideration to additional borrowings under our commercial paper program.

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

Commercial Paper

Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. At March 31, 2007, we had outstanding $581.4 million of commercial paper, net of unamortized discount of $0.6 million, bearing interest at a weighted average rate of 5.45%. At December 31, 2006, we had $443.7 million of commercial paper outstanding, net of $1.3 million of unamortized discount, at a weighted average interest rate of 5.45%. At March 31, 2007, we could issue an additional $18 million in principal amount under our commercial paper program.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. In 2007, we expect to spend approximately $1.5 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. As of March 31, 2007, we have approximately $825 million in outstanding purchase commitments for materials and services associated with our capital projects for the construction of assets that we expect to settle during the remainder of 2007. However, we will incur additional commitments as our capital projects continue to progress.

Forecasted Expenditures

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

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2007. Although we anticipate making the indicated expenditures, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. Additionally, estimates may change as a result of decisions made at a later date to revise the scope of a project. We made capital expenditures of approximately $399.3 million, including $9.2 million on core maintenance activities, during the three months ended March 31, 2007.

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

System enhancements	$ 440
Core maintenance activities	60
Southern Access expansion	810
East Texas expansion	270
	$1,580

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our estimated construction cost, actual expenditures through March 31, 2007, the incremental capacity that will become available upon completion of the project and the periods during which we expect to complete the construction. From December 31, 2006, through the first three months of 2007, we incurred approximately $348 million of capital expenditures associated with the projects listed below. The estimated amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures		Estimated Incremental Capacity			
	Estimated Total Cost	Actual Expenditures through March 31, 2007	Storage	Oil	Natural Gas	Expected Completion
	(in billions)		(KBbl)	(Kbpd)	(MMcf/d)	
Southern Access expansion (Lakehead)	$1.3	$0.297	—	400	—	2009
Clarity (East Texas)	0.6	0.404	—	—	700	In phases to late 2007
Alberta Clipper	0.8	—	—	450	—	Late 2009 to mid-2010
North Dakota system expansion	0.1	0.020	—	30	—	Late 2007
Cushing terminal storage tanks	0.1	0.050	4,970	—	—	Throughout 2007
Griffith and Superior storage tanks	0.1	0.014	1,220	—	—	Mid-2007 and mid-2008
Natural gas connects and compression	0.1	0.092	—	—	—	Various
Processing and treating plant expansions	0.3	0.170	—	—	1,130	Various
Total	$3.4	$1.047	6,190	880	1,830	

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our East Texas expansion and extension, Southern Access expansion and Alberta Clipper projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper and borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

Derivative Activities

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments at March 31, 2007 for each of the indicated calendar years:

	Notional	2007	2008	2009	2010	2011	2012
			($ in millions)				
Swaps							
Natural gas[1]	274,738,530	$(30.7)	$(39.8)	$(33.2)	$(27.2)	$(23.9)	$(4.8)
NGL[2]	8,337,949	(27.4)	(15.7)	(7.5)	(3.5)	(1.1)	—
Crude[2]	1,284,691	(7.5)	(7.8)	(2.3)	(0.8)	(0.3)	—
Options—calls							
Natural gas[1]	1,736,000	(1.1)	(1.5)	(1.3)	(1.2)	(1.1)	—
Options—puts							
Natural gas[1]	2,470,000	0.2	—	—	—	—	—
Totals		$(66.5)	$(64.8)	$(44.3)	$(32.7)	$(26.4)	$(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, 2007 was $152.8 million, an increase of $56.4 million from the $96.4 million generated during the same period in 2006. The improved operating cash flow is primarily attributable to sales of inventory in the first quarter 2007 that we did not make in the first quarter of 2006, and other changes in working capital accounts. Additionally, net cash provided by operating activities increased due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $229.2 million more in our investing activities during the three months ended March 31, 2007 in relation to the same period in 2006. The increase is primarily attributable to the $300.6 million increase in our investments in property, plant and equipment during the first quarter of 2007 over the amount spent during the same period of 2006 offset by a $70.7 million increase in our construction payables. The increase in our capital expenditures in the first quarter of 2007 is directly attributable to our previously announced expansion projects.

Financing Activities

Net cash provided by financing activities during the three months ended March 31, 2007 was $81.8 million, compared with $53.4 million for the corresponding period in 2006. The increase in financing activities is primarily attributable to net issuances of commercial paper. During the first quarter of 2007 we had $139.4 million of net commercial paper issuances, which include gross issuances of $1,136.3 million and gross repayments of $996.9 million. Additionally, we made $57.6 million in cash distributions to our partners during the three months ended March 31, 2007. On January 26, 2007, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2007. Our cash distributions to our partners were approximately $1 million more for the first quarter of 2007 compared to the first quarter of 2006 due to higher incentive distribution payments to our general partner as a result of a greater number of units outstanding.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On April 26, 2007, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2007. The distribution will be paid to unitholders of record as of May 7, 2007, of our available cash of $86.6 million at March 31, 2007, or $0.925 per common unit. Of this distribution, $58.2 million will be paid in cash, $11.9 million will be distributed in i-units to our i-unitholder, $15.9 million will be distributed in Class C units to the holders of our Class C units and $0.6 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

Effective April 1, 2007, 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 2007, and an adjustment for the Terrace surcharge as a result of lower than expected volumes moving on the Lakehead system in 2006. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.007 per barrel, to approximately $0.926 per barrel.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In February 2007, the Financial Accounting Standards Board (FASB) issued Statement No. 159, *The Fair Value Option for Financial Assets and Liabilities.* This statement provides companies with an option to report certain financial assets and liabilities at fair value. The objective of SFAS No. 159 is to reduce complexity in accounting for financial instruments and the volatility in earnings caused by measuring related financial assets and liabilities. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007. We have elected not to early adopt the provisions of SFAS No. 159, although early adoption is permitted as of the beginning of a fiscal year that begins on or before November 15, 2007, provided the entity also elects to apply the provisions of SFAS No. 157. We do not expect our adoption of SFAS No. 159 to have a material affect on our Consolidated Statements of Financial Position.

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, 2006, 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 the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provide information about our derivative financial instruments at March 31, 2007 and December 31, 2006, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At March 31, 2007						At December 31, 2006	
			Wtd Avg Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2007								
Swaps								
Receive variable/pay fixed	Natural gas	44,761,845	$ 7.62	$ 7.40	$25.0	$(15.6)	$ 8.1	$(86.7)
	NGL	106,725	46.70	43.26	0.5	(0.1)	—	(0.5)
Receive fixed/pay variable	Natural gas	44,322,680	7.00	7.93	8.6	(48.7)	79.8	(33.0)
	NGL	3,278,275	38.16	46.83	1.6	(29.4)	14.4	(23.2)
	Crude oil	286,800	41.82	68.76	—	(7.5)	—	(8.6)
Receive variable/pay variable	Natural gas	54,220,154	7.78	7.78	3.4	(3.4)	3.1	(3.7)
Options								
Calls (written)	Natural gas	275,000	8.23	4.31	—	(1.1)	—	(1.0)
Puts	Natural gas	1,009,000	8.01	6.15	0.2	—	1.0	—
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	18,633,796	8.33	7.41	18.4	(2.1)	9.5	(5.1)
Receive fixed/pay variable	Natural gas	24,958,326	6.33	8.79	1.1	(58.9)	3.6	(44.1)
	NGL	2,046,819	39.69	47.87	—	(15.7)	2.5	(7.7)
	Crude oil	337,241	45.16	69.96	—	(7.8)	—	(7.0)
Receive variable/pay variable	Natural gas	21,618,803	9.04	8.96	2.5	(0.8)	2.5	(0.4)
Options								
Calls (written)	Natural gas	366,000	8.70	4.31	—	(1.5)	—	(1.3)
Puts	Natural gas	366,000	8.70	3.40	—	—	—	—
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural gas	6,524,450	7.96	7.39	4.6	(1.2)	2.9	(2.1)
Receive fixed/pay variable	Natural gas	12,865,240	5.15	8.36	0.2	(37.3)	0.7	(31.5)
	NGL	1,909,315	42.46	46.85	—	(7.5)	1.4	(1.4)
	Crude oil	264,625	59.09	68.87	—	(2.3)	—	(1.9)
Receive variable/pay variable	Natural gas	17,602,611	8.61	8.58	1.4	(0.9)	1.4	(0.6)
Options								
Calls (written)	Natural gas	365,000	8.33	4.31	—	(1.3)	—	(1.2)
Puts	Natural gas	365,000	8.33	3.40	—	—	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural gas	2,220,125	7.76	6.09	3.3	(0.1)	2.5	(0.3)
Receive fixed/pay variable	Natural gas	9,490,000	4.11	7.93	—	(31.0)	0.2	(26.1)
	NGL	766,500	33.83	39.28	—	(3.5)	—	(1.5)
	Crude oil	213,525	63.00	67.35	—	(0.8)	—	(0.6)
Receive variable/pay variable	Natural gas	7,200,000	8.77	8.68	0.9	(0.3)	0.8	(0.1)
Options								
Calls (written)	Natural gas	365,000	7.98	4.31	—	(1.2)	—	(1.0)
Puts	Natural gas	365,000	7.98	3.40	—	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural gas	730,000	7.71	3.57	2.5	—	2.0	—
Receive fixed/pay variable	Natural gas	7,952,500	3.63	7.71	—	(26.4)	—	(21.5)
	NGL	230,315	31.70	37.51	—	(1.1)	—	(0.6)
	Crude oil	182,500	64.30	66.45	—	(0.3)	—	(0.2)
Options								
Calls (written)	Natural gas	365,000	7.71	4.31	—	(1.1)	—	(0.9)
Puts	Natural gas	365,000	7.71	3.40	—	—	—	—
Contracts maturing after 2011								
Swaps								
Receive variable/pay fixed	Natural gas	182,000	8.40	3.57	0.7	—	0.6	—
Receive fixed/pay variable	Natural gas	1,456,000	3.57	8.40	—	(5.5)	—	(4.5)

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2007 and December 31, 2006, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Accounting Treatment

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

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

If a derivative financial instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in Accumulated other comprehensive income ("AOCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas for commodity hedges and Interest expense for interest rate hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges, for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

If a derivative financial instrument is designated and qualifies as a fair value hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge's change in fair market value will be recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in Interest expense on our Consolidated Statements of Income. Similar to derivative financial instruments designated as cash flow hedges, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as “non-qualified.” Non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated derivative financial instrument contract settlement is made.

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

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

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

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative financial instruments was a liability to us at

re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

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

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

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas 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, 2007	2006
	(in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ 0.1	$ —
Non-qualified hedges	(3.2)	1.8
Marketing		
Non-qualified hedges	(13.2)	25.9
Derivative fair value gains (losses)	$(16.3)	$27.7

Derivative Positions

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

	March 31, 2007	December 31, 2006
	(in millions)	
Other current assets	$ 1.7	$ 7.2
Other assets, net	10.6	11.0
Accounts payable and other	(88.1)	(57.2)
Other long-term liabilities	(160.3)	(136.4)
	$(236.1)	$(175.4)

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

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $4.1 million associated with cash flow hedges that were subsequently de-designated. These unrealized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three months ended March 31, 2007, we reclassified losses of $16.2 million from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

We 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, 2007. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. No changes in our internal control over financial reporting were made during the three months ended March 31, 2007, that would materially affect our internal control over financial reporting, nor were any corrective actions with respect to significant deficiencies or material weaknesses necessary subsequent to that date.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 9, which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to our risk factors as previously disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

Item 6. Exhibits

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

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: April 30, 2007

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

Date: April 30, 2007

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

Index of Exhibits

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

3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 16, 2006).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
4.2	Registration Rights Agreement, dated April 2, 2007 by and among Enbridge Energy Partners, L.P. Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K dated April 2, 2007).
10.1	Second Amended and Restated Credit Agreement dated as of April 4, 2007, by and among the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1of the Partnership's Current Report on Form 8-K dated April 10, 2007).
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.