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, 2005

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 checkmark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒ No ☐

The Registrant had 46,802,634 Class A common units outstanding as of May 5, 2005.

TABLE OF CONTENTS

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 our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three months ended March 31, 2005	2004
	(unaudited; in millions, except per unit amounts)	
Operating revenue	$1,250.1	$982.5
Operating expenses		
Cost of natural gas	1,065.2	822.0
Derivative fair value loss (gain) (Note 4)	7.0	(0.2)
Operating and administrative	74.4	62.3
Power	17.0	17.2
Depreciation and amortization	33.3	28.6
	1,196.9	929.9
Operating income	53.2	52.6
Interest expense	(25.6)	(21.6)
Other income	0.6	2.1
Net income	$ 28.2	$ 33.1
Net income allocable to common and i-units	$ 22.2	$ 27.6
Net income per common and i-unit (basic and diluted) (Note 3)	$ 0.37	$ 0.50
Weighted average units outstanding	60.6	54.7

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,	
	2005	2004
	(unaudited; in millions)	
Net income	$ 28.2	$33.1
Unrealized loss on derivative financial instruments	(74.2)	(19.0)
Comprehensive (loss) income	$(46.0)	$14.1

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,	
	2005	2004
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 28.2	$ 33.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	33.3	28.6
Derivative fair value loss (gain) (Note 4)	7.0	(0.2)
Environmental liabilities	—	(2.0)
Other	(0.3)	0.2
Changes in operating assets and liabilities, net of acquired working capital:		
Receivables, trade and other	(6.9)	15.2
Due from General Partner and affiliate	1.8	6.3
Accrued receivables	31.2	(24.7)
Inventory	15.5	7.1
Current and long-term other assets	(0.7)	10.5
Due to General Partner and affiliates	(7.8)	5.6
Accounts payable and other	(15.0)	13.4
Accrued purchases	(18.5)	18.6
Interest payable	21.2	19.8
Property and other taxes payable	0.3	2.1
Net cash provided by operating activities	89.3	133.6
Cash used in investing activities		
Additions to property, plant and equipment	(72.9)	(21.6)
Changes in construction payables	(6.7)	1.1
Asset acquisitions, net of cash acquired (Note 2)	(165.7)	(130.0)
Other	(0.7)	—
Net cash used in investing activities	(246.0)	(150.5)
Cash provided by financing activities		
Proceeds from unit issuances, net (Note 6)	127.5	22.0
Distributions to partners (Note 6)	(50.7)	(46.8)
Borrowings under debt agreements	750.0	583.3
Repayments of debt	(680.0)	(530.0)
Other	0.1	—
Net cash provided by financing activities	146.9	28.5
Net (decrease) increase in cash and cash equivalents	(9.8)	11.6
Cash and cash equivalents at beginning of year	78.3	64.4
Cash and cash equivalents at end of period	$ 68.5	$ 76.0

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

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

	March 31, 2005	December 31, 2004
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 68.5	$ 78.3
Receivables, trade and other, net of allowance for doubtful accounts of $4.0 in 2005 and 2004	78.6	71.7
Due from General Partner and affiliates	5.9	7.7
Accrued receivables	347.0	378.2
Inventory	69.0	84.5
Other current assets	11.0	13.4
	580.0	633.8
Property, plant and equipment, net	2,971.9	2,778.0
Other assets, net	25.5	27.7
Goodwill	257.2	257.2
Intangibles, net	87.4	74.0
	$3,922.0	$3,770.7
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 2.1	$ 9.9
Accounts payable and other (Note 5)	141.6	136.4
Accrued purchases	332.9	351.4
Interest payable	31.1	12.3
Property and other taxes payable	23.6	23.3
Current maturities of long-term debt	31.0	31.0
	562.3	564.3
Long-term debt	1,629.5	1,559.4
Loans from General Partner and affiliates	144.5	142.1
Environmental liabilities (Note 7)	5.4	5.3
Deferred credits	151.6	101.7
	2,493.3	2,372.8
Commitments and contingencies (Note 7)		
Partners' capital		
Class A common units (Units issued—46,802,634 in 2005 and 44,296,134 in 2004)	1,111.6	1,021.6
Class B common units (Units issued—3,912,750 in 2005 and 2004)	69.8	66.7
i-units (Units issued—11,101,389 in 2005 and 10,902,409 in 2004)	409.0	399.4
General Partner	33.3	31.0
Accumulated other comprehensive loss	(195.0)	(120.8)
	1,428.7	1,397.9
	$3,922.0	$3,770.7

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the financial position as of March 31, 2005 and December 31, 2004; and the results of operations and cash flows for the three month periods ended March 31, 2005 and 2004. The results of operations for the three months ended March 31, 2005, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the natural gas business, maintenance activities and the impact of forward natural gas prices on certain derivative financial instruments that are accounted for using mark-to-market accounting. In addition, prior period information presented in these consolidated financial statements includes reclassifications that were made to conform to the current period presentation. These reclassifications have no effect on previously reported net income or partners' capital. The interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

2. ACQUISITIONS

North Texas Natural Gas System

In January 2005, we acquired natural gas gathering and processing assets for $164.6 million in cash, including transaction costs of $0.5 million. We funded the acquisition with borrowings under our existing credit facilities. The assets acquired serve the Fort Worth Basin, which are mature, but experiencing minimal production decline rates and include:

- 2,200 miles of gas gathering pipelines;
- four processing plants with aggregate processing capacity of 121 million cubic feet of natural gas per day ("MMcf/d").

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the gas and then selling the natural gas liquids ("NGLs") and residue gas streams. The assets and results of operations are included in our Natural Gas segment from the date of acquisition.

The purchase price and the allocation to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:	
Cash paid, including transaction costs	$164.6
Allocation of purchase price:	
Property, plant and equipment, including construction in progress	151.6
Intangibles, including contracts	14.3
Current liabilities	(0.9)
Contingent liabilities	(0.4)
Total	$164.6

3. NET INCOME PER COMMON AND i-UNIT

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

	Three months ended March 31,	
	2005	2004
	(in millions, except per unit amounts)	
Net income	$28.2	$33.1
Allocations to the General Partner:		
Net income allocated to General Partner	(0.6)	(0.7)
Incentive distributions to General Partner	(5.3)	(4.7)
Historical cost depreciation adjustments	(0.1)	(0.1)
	(6.0)	(5.5)
Net income allocable to common and i-units	$22.2	$27.6
Weighted average units outstanding	60.6	54.7
Net income per common and i-unit (basic and diluted)	$0.37	$0.50

4. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

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

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). Under the guidance of Statement of Financial Accounting Standards No. 133 *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), changes in the fair market value of derivatives that qualify as highly effective cash flow hedges are recorded as components of accumulated other comprehensive income until the hedged transactions occur ("hedge accounting"). Hedge accounting can apply to either a hedge of future cash flows or to a liability. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. When the hedged transaction occurs, the fair value of the derivative is recognized in earnings, along with the offsetting fair value of the physical transaction. For those derivative financial instruments that do not qualify for cash flow hedge

4. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK (Continued)

accounting, the total change in fair value is recorded directly in earnings each period. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment in order to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. However, to qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

The majority of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, there are some instances where the hedge structure does not meet the requirements of the standard to apply hedge accounting. For example, in our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133. As another example, if a derivative financial instrument, which had originally qualified for hedge accounting, is offset by an equal and opposite transaction in order to reverse the hedge position, which often occurs in our gas storage management portfolio when the underlying injection or withdrawal schedules change, both of the transactions no longer qualify for hedge accounting. As such, all of these above mentioned non-qualified hedges are accounted for in the Consolidated Statements of Income through mark-to-market accounting. These derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. 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.

The other significant instance where our derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 is in our Natural Gas segment. We had previously entered into natural gas collars in order to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship and contemporaneously re-designated the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to perfectly match the indices. This is a sound economic hedging strategy, however, since these instruments were out of the money at re-designation, they are considered net written options under SFAS No. 133. Therefore, these instruments do not qualify for hedge accounting upon re-designation and are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with their 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. These interim mark-to-market fluctuations do not have any cash flow impact.

Derivative Fair Value Loss (Gain)

The Derivative fair value loss (gain) on our Consolidated Statements of Income is comprised of two components:

1. the change in fair value of the ineffective portion of our cash flow hedges; and

4. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK (Continued)

2. the change in fair value (or, mark-to-market) of our non-qualified hedges.

	Three months ended March 31, 2005	Three months ended March 31, 2004
Hedge ineffectiveness loss		
Natural Gas segment	$ 0.2	$ —
Mark-to-market loss (gain)		
Natural Gas segment	8.2	—
Marketing segment	(1.4)	(0.2)
Derivative fair value loss (gain)	$ 7.0	$(0.2)

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

	March 31, 2005	December 31, 2004
	(dollars in millions)	
Receivables, trade and other	$ 6.5	$ 8.2
Other assets, net	7.1	10.1
Accounts payable and other	(70.5)	(44.7)
Deferred credits	(143.6)	(93.4)
	$(200.5)	$(119.8)

In our Consolidated Statements of Comprehensive Income, we record the change in fair value of our highly effective cash flow hedges. The increase in the unrealized loss recorded in the first quarter of 2005 compared with the corresponding period in 2004 is primarily due to the significant increases in forward natural gas and NGL prices. As a result of the Partnership's portfolio of derivative financial instruments, which is largely comprised of long-term fixed price sales agreements, the significant increase in forward commodity prices quarter over quarter has increased our obligation associated with these derivative transactions.

5. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $17.7 million at March 31, 2005 and $25.3 million at December 31, 2004, are included in Accounts Payable and other on the Consolidated Statement of Financial Position.

6. PARTNERS' CAPITAL

Cash and i-unit Distributions

In February 2005, the Partnership paid distributions of $0.925 per common unit representing its available cash of $61.0 million at December 31, 2004. Of this distribution, $50.7 was paid in cash, $10.1 was distributed in additional i-units to the holders of our i-units and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

6. PARTNERS' CAPITAL (Continued)

Common unit offering

On February 11, 2005, the Partnership issued 2,506,500 Class A common units at $49.875 per unit, which generated proceeds of approximately $124.8 million, net of offering expenses. Additionally, the General Partner contributed $2.7 million to us to maintain its 2% general partner interest in the Partnership. We used the proceeds from this offering to repay amounts outstanding under our Three-year term credit facility.

7. COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Environmental Liabilities

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

As of March 31, 2005 and December 31, 2004, the Partnership has recorded $3.7 million and $3.6 million in current liabilities and $5.4 million and $5.3 million in long-term liabilities primarily to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain liquids and natural gas assets.

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.

8. 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 in assessing performance.

Each of our reportable segments is a business unit that offers different services and products that are managed separately, as each business segment requires different operating strategies. In June 2004, we changed our reporting segments to reflect changes in the way we make resource allocation decisions, evaluate performance and promote the achievement of our long-term objectives. Financial information for prior periods was reclassified to reflect the new segmentation. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

8. SEGMENT INFORMATION (Continued)

The following tables present certain financial information relating to our business segments (in millions):

	As of and for the three months ended March 31, 2005				
	Liquids	Natural Gas	Marketing	Corporate	Total
Total revenue	$ 96.5	$ 924.6	$693.8	$ —	$1,714.9
Less: Intersegment revenue	—	439.0	25.8	—	464.8
Operating revenue	96.5	485.6	668.0	—	1,250.1
Cost of natural gas	—	398.1	667.1	—	1,065.2
Derivative fair value loss (gain)	—	8.4	(1.4)	—	7.0
Operating and administrative	31.9	41.1	0.8	0.6	74.4
Power	17.0	—	—	—	17.0
Depreciation and amortization	17.6	15.6	0.1	—	33.3
Operating income	30.0	22.4	1.4	(0.6)	53.2
Interest expense	—	—	—	(25.6)	(25.6)
Other income	—	—	—	0.6	0.6
Net income	$ 30.0	$ 22.4	$ 1.4	$(25.6)	$ 28.2
Total assets	$1,654.5	$1,908.0	$279.0	$ 80.5	$3,922.0
Goodwill	$ —	$ 236.8	$ 20.4	$ —	$ 257.2
Capital expenditures (excluding acquisitions)	$ 13.1	$ 58.7	$ —	$ 1.1	$ 72.9

	As of and for the three months ended March 31, 2004				
	Liquids	Natural Gas	Marketing	Corporate	Total
Total revenue	$ 91.7	$ 664.5	$596.9	$ —	$1,353.1
Less: Intersegment revenue	—	329.8	40.8	—	370.6
Operating revenue	91.7	334.7	556.1	—	982.5
Cost of natural gas	—	268.7	553.3	—	822.0
Derivative fair value loss (gain)	—	—	(0.2)	—	(0.2)
Operating and administrative	27.8	32.4	0.8	1.3	62.3
Power	17.2	—	—	—	17.2
Depreciation and amortization	16.1	12.5	—	—	28.6
Operating income	30.6	21.1	2.2	(1.3)	52.6
Interest expense	—	—	—	(21.6)	(21.6)
Other income	—	—	—	2.1	2.1
Net income	$ 30.6	$ 21.1	$ 2.2	$(20.8)	$ 33.1
Total assets	$1,622.6	$1,479.7	$199.1	$ 58.0	$3,359.4
Goodwill	$ —	$ 236.8	$ 20.4	$ —	$ 257.2
Capital expenditures (excluding acquisitions)	$ 7.9	$ 13.3	$ —	$ 0.4	$ 21.6

9. SUBSEQUENT EVENTS

Distribution to Partners

On April 25, 2005, Enbridge Energy Management, L.L.C.'s ("Enbridge Management") Board of Directors declared a distribution payable on May 13, 2005. The distribution will be paid to unitholders of record as of May 4, 2005, of its available cash of $63.8 million at March 31, 2005, or $0.925 per common unit. Of this distribution, $53.3 million will be paid in cash, $10.3 million will be distributed in i-units to its i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

Amendment to Credit Agreement

In April 2005, we entered into the third amendment to the Amended and Restated Credit Agreement dated as of January 24, 2003 (the "Credit Facility") to, among other things, extend the maturity of the Credit Facility for a period of five years to April 2010; increase the letter of credit sublimit from $100 million to $175 million; and grant the Company the right to request, subject to approval by its board of directors, an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion.

Commercial Paper Program

In April 2005, we established a $600 million commercial paper program that is backstopped by our $600 million Credit Facility. We expect to reduce our short-term borrowing costs by utilizing the commercial paper market. In April 2005, we repaid $85.0 million of our Credit Facility from proceeds we obtained from issuing commercial paper under this program. Our Credit Facility will remain undrawn and available to backstop our commercial paper program. The commercial paper program does not contain any clauses or ratings triggers that would restrict our borrowing under the Credit Facility.

Regulatory Matters—Lakehead system

Effective April 1, 2005, Enbridge Energy, Limited Partnership ("Lakehead Partnership"), a subsidiary of the Partnership, filed a new tariff with the Federal Energy Regulatory Commission ("FERC"). This new tariff reflects the annual calculation of the SEP II and Facilities surcharges based on true-ups of prior year amounts and estimates for 2005, and an adjustment for the Terrace surcharge as a result of lower than expected volumes moving on the Lakehead system. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.035 per barrel, to approximately $0.865 per barrel.

Regulatory Matters—FERC Policy on Income Tax Allowances

On May 4, 2005, the FERC adopted a policy to permit cost-of-service rates to reflect actual or potential income tax liability for all public utility assets, regardless of the form of ownership. The policy statement stems from an opinion issued by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast Products, LLC v. FERC* that remanded the FERC's decisions on tax allowance treatment in an oil pipeline rate proceeding involving SFPP, L.P., an unrelated pipeline company.

Under the policy, all entities or individuals owning public utility assets would be permitted an income tax allowance on the income from those assets, provided that they have an actual or potential income tax liability on that public utility income. As a result, a taxpaying corporation, partnership, limited liability corporation, or other pass-through entity would be permitted an income tax allowance

9. SUBSEQUENT EVENTS (Continued)

on the income imputed to the corporation, or to the partners or the members of pass-through entities, provided that the corporation or the partners or members have an actual or potential tax liability on that income. Any pass-through entity seeking an income tax allowance in a specific rate proceeding will be required to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. Management is evaluating the new FERC Policy. At this time we do not believe the adoption of this policy by the FERC will have a material effect on our financial position, results of operations or cash flows.

10. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting for Conditional Asset Retirement Obligations

In March 2005 the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*. This interpretation clarifies the meaning of "conditional asset retirement obligation" as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations* as referring to a legal obligation to perform an asset retirement activity where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of an entity. The obligation to perform the retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement. The interpretation requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. We are currently evaluating the effect that application of this interpretation will have on our financial statements.

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

RESULTS OF OPERATIONS—OVERVIEW

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

- Interstate transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transmission of natural gas;
- Providing supply, transmission and sales service, including purchasing and selling natural gas and natural gas liquids ("NGLs").

We primarily provide fee-based services to our customers to minimize commodity price risks. However, in our natural gas business, 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, 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.

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

The following table reflects operating income by business segment and corporate charges for each of the periods presented.

	Three months ended March 31,	
	2005	2004
	(unaudited; in millions)	
Operating Income		
Liquids	$ 30.0	$ 30.6
Natural Gas	22.4	21.1
Marketing	1.4	2.2
Corporate, operating and administrative	(0.6)	(1.3)
Total Operating Income	$ 53.2	$ 52.6
Interest expense	(25.6)	(21.6)
Other income	0.6	2.1
Net Income	$ 28.2	$ 33.1

We acquired natural gas gathering and processing assets in north Texas in January 2005. The facilities acquired include approximately 2,200 miles of natural gas gathering pipelines and four natural gas processing plants with an aggregate processing capacity of 121 MMcf/d of natural gas. This system predominantly serves producers in the Fort Worth Basin Conglomerate formation and is located in an area where future drilling is expected from producers extending the Barnett Shale play's western flank. We combined these assets with our existing North Texas assets and have included them in the operating results of our Natural Gas segment from the date of acquisition.

Total consolidated net income for the first quarter of 2005 was $28.2 million, compared with $33.1 million for the first quarter of 2004. The decrease in net income is primarily due to lower operating results in our Liquids and Marketing segments, as well as higher interest expense. Results for our Natural Gas segment were lower than expected due to a noncash derivatives fair value loss. This was caused by a change from hedge accounting to mark-to-market accounting for long-term natural gas collars that are used to manage our commodity price risk.

Earnings per unit for the first quarter of 2005 was $0.37 per unit, compared with $0.50 per unit for the first quarter of 2004. The decrease was a result of lower net income and a greater number of units outstanding during the first quarter of 2005. Since the first quarter of 2004, the Partnership has issued 6,186,500 Class A common units and 850,221 i-units that have increased the weighted average number of common units outstanding from 54.7 million in the first quarter of 2004 to 60.6 million in the first quarter of 2005.

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

Our Liquids segment accounted for $30.0 million of operating income, or 56% of consolidated operating income in the first quarter of 2005. This was a decrease of $0.6 million in operating income over the same period in 2004. A full quarter's contribution by the Mid-Continent system and stronger results on North Dakota were mostly offset by lower results on the Lakehead system. We purchased the Mid-Continent system on March 1, 2004.

Operating revenue for the first quarter of 2005 was $96.5 million, compared with $91.7 million for the first quarter of 2004. The increase of $4.8 million was primarily due to a full quarter contribution from the Mid-Continent assets in 2005, compared with a one-month contribution in 2004 and increased volumes and longer hauls on our North Dakota system. This increase was partially offset by lower results on the Lakehead system primarily due to lower delivery volumes.

Volumes on the Lakehead system decreased approximately 5%, from 1.406 million barrels per day ("Bpd") during the first quarter of 2004 to 1.336 million Bpd during the same period in 2005. This resulted in lower operating revenue of approximately $4.3 million. The decrease is primarily the result of lower than expected supply from Suncor, an oil sands producer in Alberta, Canada. On January 4, 2005, a fire occurred at their upgrader site and production was reduced by almost half to approximately 110,000 Bpd. Suncor has stated that full production should resume during the third quarter 2005. Until that time, we expect deliveries on the Lakehead system to be negatively impacted by the decreased Suncor production.

The following table sets forth the operating statistics for the Liquids assets for the periods presented. Mid-Continent results are for a full quarter in 2005, compared to one month of March in 2004.

	Three months ended March 31,	
	2005	2004
	(average Bpd, in thousands)	
Lakehead system:		
United States	1,009	1,014
Province of Ontario	327	392
Total deliveries	1,336	1,406
Barrel miles (billions)	83	90
Average haul (miles)	689	710
Mid-Continent system deliveries	189	243
North Dakota system deliveries	89	74

Operating and administrative expenses for the Liquids segment increased by $4.1 million or 15% in the first quarter of 2005, compared with the same period in 2004. The change was primarily due to an increase in oil measurement losses of $4.6 million, and the full quarter operations of the Mid-Continent system of $1.2 million, partially offset by lower business development costs of $1.5 million.

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

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

During the first quarter of 2005, the increase in oil measurement losses was a function of three factors:

1. High oil prices made the absolute value of normal physical losses more expensive. During the first quarter of 2005, the average West Texas Intermediate crude oil price was approximately $50 per barrel compared with approximately $35 per barrel during the same period in 2004;
2. Wider light/heavy crude price differentials made degradation losses more expensive. During the first quarter of 2005, light/heavy differentials were approximately $17 per barrel compared with approximately $10 per barrel in 2004; and
3. There is limited liquidity in the specific crude types which must be transacted to settle positions naturally created by the pipeline system's operations, especially when a price trend is anticipated by crude oil marketers. As a result, the Partnership carried an unintended short position into the first quarter of 2005, on which it experienced a loss prior to settling the position.

Natural Gas

The following table presents the average daily volume for each of the major systems in our Natural Gas segment during the periods presented, in million British thermal units per day ("MMBtu/d").

	Three months ended March 31,	
	2005	**2004**
East Texas	787,000	583,000
Anadarko	423,000	276,000
North Texas	265,000	192,000
South Texas	38,000	44,000
UTOS	198,000	206,000
MidLa	105,000	117,000
AlaTenn	83,000	80,000
KPC	59,000	89,000
Bamagas	13,000	9,000
Other Major Intrastates	249,000	192,000
Total	**2,220,000**	**1,788,000**

Our Natural Gas segment accounted for $22.4 million of operating income, or 42% of consolidated operating income in the first quarter of 2005. This was an increase of $1.3 million in operating income over the corresponding period in 2004.

Average daily volumes on our major natural gas systems increased 24% in the first quarter of 2005, compared with the corresponding period in 2004. The increase in volumes is primarily the result of additional wellhead supply contracts on our East Texas and Anadarko systems as well as the additional volumes on the North Texas system associated with the acquisition of additional gathering and processing assets in January 2005. We expect volumes in these areas to continue to increase as a result of increased drilling activity in the Anadarko basin, the Bossier trend and the Barnett Shale area.

A portion of our Natural Gas segment is exposed to commodity price risks associated with percent of proceeds or percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive at the time we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate. The remainder of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services.

A relatively small, but variable element of the Natural Gas segment's operating income is derived from keep-whole processing of natural gas. This contract structure requires us to process natural gas at times when it may not be economical to do so. This can happen when natural gas prices are unusually high or natural gas liquids prices are unusually low. During the first quarter of 2005, although natural gas prices were unusually high, they were more than offset by favorable NGL prices. Operating revenue less cost of natural gas derived from keep-whole processing for the three months ended March 31, 2005, was approximately $3.7 million compared to $2.2 million for the same period in 2004.

The positive growth in our natural gas and NGL gathering, processing and transportation volumes for the first quarter of 2005 was partially offset by increases in workforce related costs, increases in costs of fuel and down time for maintenance activities at two of our processing plants along with the related costs associated with performing this maintenance. Additionally, we recorded mark-to-market adjustments of $8.2 million to expense as a result of certain derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 (refer also to the discussion in Part I, Item 3. Quantitative and Qualitative Disclosures About Market Risk). Although changes in the fair value of these specific derivative financial instruments do not affect our cash flow, we anticipate these changes will result in more volatility in our consolidated statements of income going forward due to the inherent volatility of the commodity prices.

Marketing

Our Marketing segment accounted for $1.4 million of operating income, or 2% of consolidated Partnership operating income in the first quarter of 2005. This was a decrease of $0.8 million in operating income compared with the corresponding period in 2004. Included in 2005 are gains of approximately $1.4 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The Partnership uses derivative financial instruments to economically hedge potential commodity price movements. Specifically, natural gas swaps and certain storage swaps are strategies commonly used. First, financial natural gas basis swap transactions are employed to mitigate the risk on index pricing differentials between its physical gas purchases and corresponding gas sales. When the gas sales pricing index is different from the gas purchase pricing index, the Partnership is exposed to relative changes in those two index levels. By entering into a basis swap between those two indices, the Partnership can effectively lock in the margin on the combined gas purchase and the gas sale, removing any market price risk on the physical transactions. In addition to natural gas basis swaps, the Partnership contracts for storage to assist balancing natural gas supply and end use market sales. In order to mitigate storage fees for the use of the storage capacity, the forward price between the summer and winter ("spread") is hedged by buying forward storage injection swaps and selling storage withdrawal swaps. When these spread values increase or decrease as a result of market price movements, the Partnership earns additional profitability 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 will impact the income statement. In the first quarter 2004, we recognized a gain of $0.2 million in connection with our derivative transactions.

Our Marketing segment continues to be impacted by lower unit margins on natural gas volumes purchased due to physical pipeline constraints that will remain until our East Texas system expansion is complete. Performance of the Marketing segment was also negatively impacted by demand charges on new third-party pipeline capacity that is utilized to transport natural gas from markets that are over supplied with natural gas to new markets. Pricing in our natural gas supply markets is expected to come under increasing pressure due to higher natural gas supplies from the Rocky Mountains and North Texas. For this reason we have increased our commitments on third-party pipelines to provide more attractive market outlets for our natural gas supply.

Corporate

Interest expense was $25.6 million for the three months ended March 31, 2005, compared with $21.6 million for the corresponding period in 2004. The increase is a result of higher debt balances and a higher weighted average interest rate of approximately 5.7% during the first quarter of 2005, compared with approximately 5.3% during the same period in 2004.

LIQUIDITY AND CAPITAL RESOURCES

We believe that our ability to generate cash flow, in addition to our access to capital resources, is sufficient to meet the demands of our current and future operating growth and investment needs. Our primary cash requirements consist of normal operating expenses, maintenance and expansion capital expenditures, debt service payments, distributions to partners and acquisitions of new assets or businesses. Short-term cash requirements, such as operating expenses, maintenance capital expenditures and quarterly distributions to partners, are expected to be funded from our operating cash flows. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from operating activities, borrowings under the commercial paper program we established in April 2005 and our credit facilities, and the issuance of additional equity and debt securities, including common units and i-units. 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.

On February 11, 2005, we issued an additional 2,506,500 Class A common units at $49.875 per unit, which generated proceeds, net of offering expenses, of approximately $124.8 million. We used the proceeds from this offering to repay borrowings under our three-year credit facility. Additionally, the General Partner contributed $2.7 million to us to maintain its 2% general partner interest in the Partnership.

Working capital, defined as current assets less current liabilities, decreased by $51.8 million to $17.7 million at March 31, 2005, compared with $69.5 million at December 31, 2004. This decrease was primarily attributable to a reduction in current assets from lower accrued receivables and inventory balances. Inventory is lower as we are moving more natural gas out of storage to markets. Additionally, interest payable increased from the balance at December 31, 2004, due to the timing of interest payments and increases in the amount of debt outstanding from the prior year.

At March 31, 2005, cash and cash equivalents totaled $68.5 million, compared with $78.3 million at December 31, 2004. Of the cash balance, $63.8 million ($0.925 per unit) is available for cash distribution to our unitholders on May 13, 2005. Of this distribution, $53.3 million will be paid in cash, $10.3 million will be distributed in i-units to i-unitholders and $0.2 million retained from our General Partner in respect of this i-unit distribution.

Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2005 was $89.3 million, compared with $133.6 million for the same period in 2004. The decrease in 2005 was primarily the result of 1) declines in the price of natural gas from December 31, 2004 to March 31, 2005, which resulted in decreases in accounts payable and receivables in the current period; 2) increases in the price of natural gas from December 31, 2003 to March 31, 2004, which resulted in increases in accounts payable and receivables in the corresponding period for the prior year; and 3) general timing differences in the collection on and payment of the Partnership's related party and current accounts.

Investing Activities

Net cash used in investing activities during the three months ended March 31, 2005 was $246.0 million, compared with $150.5 million for the same period in 2004. The increase of $95.5 million was primarily attributable to greater amounts expended for the acquisition of the North Texas Gathering system than the amount paid for the Mid-Continent and Palo Duro systems acquired in the first quarter of 2004. We acquired gathering and processing assets in north Texas for approximately $164.6 million in January 2005. In addition to our acquisitions, we spent approximately $72.9 million in connection with our core maintenance and system enhancement projects, representing an increase of $51.3 million over the $21.6 million spent in the first quarter of 2004, primarily due to the continued construction of our East Texas system expansion. Additional information regarding our capital expenditures is provided below.

Financing Activities

Net cash provided by financing activities during the three months ended March 31, 2005 was $146.9 million, compared with $28.5 million for the corresponding period in 2004. The increase of $118.4 million in cash flow is primarily due to the proceeds we received from the additional Class A common units issued in February 2005 and net borrowings under our credit agreements, partially offset by an increase in distributions to our partners. Distributions to partners were higher in 2005 due to an increase in the number of units outstanding, as well as a related increase in the general partner incentive distributions resulting from the larger number of units outstanding.

CAPITAL EXPENDITURES

We categorize 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 are worn, obsolete or approaching the end of their useful lives. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards. We made capital expenditures of approximately $72.9 million, including $4.1 million on core maintenance activities, during the three months ended March 31, 2005. For the full year 2005, we anticipate capital expenditures to approximate $351.0 million, as illustrated in the following table below:

	(in millions)
System enhancements	$252.0
Core maintenance activities	41.0
East Texas expansion	58.0
	$351.0

As of March 31, 2005, we have entered into contractual commitments totaling approximately $30.4 million. Of this amount, approximately $19.0 million relates to the East Texas system expansion and $11.4 million relates to the construction of storage tanks on the Mid-Continent system. We expect to settle these contractual commitments by December 31, 2005.

We anticipate funding the expenditures temporarily through our bank credit facilities or our commercial paper program, with permanent debt and equity funding being provided 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 both ensure 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.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution Declaration

On April 25, 2005, our Board of Directors declared a distribution payable on May 13, 2005, to unitholders of record as of May 4, 2005, of its available cash of $63.8 million at March 31, 2005, or $0.925 per common unit. Of this distribution, $53.3 million will be paid in cash, $10.3 million will be distributed in i-units to i-unitholders and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

Amendment to Credit Agreement

In April 2005, we entered into the third amendment to the Amended and Restated Credit Agreement dated as of January 24, 2003 (the "Credit Facility") to, among other things, extend the maturity of the Credit Facility for a period of five years to April 2010; increase the letter of credit sublimit from $100 million to $175 million; and grant the Company the right to request, subject to approval by its board of directors, an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion.

Commercial Paper Program

In April 2005, we established a $600 million commercial paper program that is backstopped by our $600 million Credit Facility. We expect to reduce our short-term borrowing costs by utilizing the commercial paper market. In April 2005, we repaid $85.0 million of our Credit Facility from proceeds we obtained from issuing commercial paper under this program. Our Credit Facility will remain undrawn and available to backstop our commercial paper program. The commercial paper program does not contain any clauses or ratings triggers that would restrict our borrowing under the Credit Facility.

Regulatory Matters—Lakehead system

Effective April 1, 2005, Enbridge Energy, Limited Partnership ("Lakehead Partnership"), a subsidiary of the Partnership, filed a new tariff with the Federal Energy Regulatory Commission ("FERC"). This new tariff reflects the annual calculation of the SEP II and Facilities surcharges based on true-ups of prior year amounts and estimates for 2005, and an adjustment for the Terrace surcharge as a result of lower than expected volumes moving on the Lakehead system. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.035 per barrel, to approximately $0.865 per barrel.

Regulatory Matters—FERC Policy on Income Tax Allowances

On May 4, 2005, the FERC adopted a policy to permit cost-of-service rates to reflect actual or potential income tax liability for all public utility assets, regardless of the form of ownership. The policy statement stems from an opinion issued by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast Products, LLC v. FERC* that remanded the FERC's decisions on tax allowance treatment in an oil pipeline rate proceeding involving SFPP, L.P., an unrelated pipeline company.

Under the policy, all entities or individuals owning public utility assets would be permitted an income tax allowance on the income from those assets, provided that they have an actual or potential income tax liability on that public utility income. As a result, a taxpaying corporation, partnership, limited liability corporation, or other pass-through entity would be permitted an income tax allowance on the income imputed to the corporation, or to the partners or the members of pass-through entities, provided that the corporation or the partners or members have an actual or potential tax liability on that income. Any pass-through entity seeking an income tax allowance in a specific rate proceeding will be required to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. Management is evaluating the new FERC Policy. At this time we do not believe the adoption of this policy by the FERC will have a material effect on our financial position, results of operations or cash flows.

FUTURE PROSPECTS

Liquids

Average daily crude oil deliveries on our Lakehead system are expected to decrease by approximately 20,000 Bpd during 2005 to approximately 1.38 million Bpd, from our previous forecast of 1.40 million Bpd. This also represents a year-over year decrease of approximately 42,000 Bpd, from 2004 deliveries of 1.422 million Bpd. The decrease is primarily attributable to the early January 2005 fire at the Suncor oil sands plant in Alberta, a major producer of crude oil in western Canada. Suncor estimates a full recovery during the third quarter of 2005, which should result in a substantial increase in western Canadian crude oil supply and deliveries on our Lakehead system.

Two market access initiatives previously announced by us and Enbridge Inc. ("Enbridge"), the Southern Access project and the Spearhead Pipeline project, respectively, continue to be pursued. The Canadian Association of Petroleum Producers ("CAPP") continues to review various pipeline expansion options to transport western Canadian crude oil to new markets. We have presented both a single-project option as well as a multi-stage expansion of the Lakehead system referred to as the Southern Access project. Our ongoing discussions with individual customers indicate that a phased expansion approach is a cost effective way to provide capacity out of western Canada to the United States when required. The first two phases of Southern Access would provide an additional 215,000 Bpd of capacity between Superior, Wisconsin and Chicago, Illinois at an estimated cost of $400 million. The third phase would cost about $300 million and would provide incremental capacity of 130,000 Bpd into the Chicago area. The final phase would then extend this pipeline further south to either Wood River or Patoka, Illinois to provide capacity for further Canadian crude oil movements to the new markets being served from these hubs.

In 2003, Enbridge acquired a 90% stake in the Spearhead Pipeline, which runs from Cushing, Oklahoma to Chicago. After a successful open season in the fall of 2004, Enbridge is currently in the process of reversing the flow of the Spearhead Pipeline so that it will provide capacity to deliver 125,000 Bpd into the major oil hub at Cushing by 2006. This line could subsequently be expanded to accommodate up to 160,000 Bpd. The Federal Energy Regulatory Commission approved the application for Spearhead transportation tariffs on March 3, 2005. A portion of the Spearhead Pipeline's revenue requirement will be rolled into Enbridge's Canadian mainline tariffs, which must be approved by Canada's National Energy Board. This approval is anticipated to be received during the second quarter of 2005. We expect to benefit following the reversal, as western Canadian crude oil will be carried on the Lakehead system as far as Chicago, and then transferred to the Spearhead Pipeline to continue to this new market.

Natural Gas

We continue to assess various acquisition and expansion opportunities to pursue our strategy for growth. The market for acquiring energy transportation assets is active and competition among prospective acquirers of assets has been significant. We remain committed to making accretive acquisitions in or near areas where we already operate. These situations present the best opportunities for consolidation savings and enhancement of our market position.

Construction continues on our new 500 MMcf/d intrastate transmission pipeline to carry increased volumes of natural gas to the pipeline hub at Carthage, Texas. Carthage access is important to natural gas shippers because it offers a number of connections to interstate pipelines, which tend to support more favorable margins to producers. We expect to bring the system on line in the middle of 2005. Related to this new transmission pipeline are a series of new projects totaling $75 million approved by the Enbridge Management Board of Directors, which increases the capacity on our East Texas system and is expected to be completed by early 2006.

Construction of our Anadarko system expansion continues. The first phase of the expansion added 100 MMcf/d of processing capacity at a cost of $38 million and entered service in April 2005. We are now proceeding with increasing the scale of that processing plant to 150 MMcf/d. The cost of this second phase is approximately $14 million and we expect to be complete by the end of the fourth quarter of 2005.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

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

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). Under the guidance of SFAS No. 133, changes in the fair market value of derivatives that qualify as highly effective cash flow hedges are recorded as components of accumulated other comprehensive income until the hedged transactions occur ("hedge accounting"). Hedge accounting can apply to either a hedge of future cash flows or to a liability. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. When the hedged transaction occurs, the fair value of the derivative is recognized in earnings, along with the offsetting fair value of the physical transaction. For those derivative financial instruments that do not qualify for cash flow hedge accounting, the total change in fair value is recorded directly in earnings each period. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment in order to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. However, to qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

The majority of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, there are some instances where the hedge structure does not meet the requirements of the standard to apply hedge accounting. For example, in our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133. As another example, if a derivative financial instrument, which had originally qualified for hedge accounting, is offset by an equal and opposite transaction in order to reverse the hedge position, which often occurs in our gas storage management portfolio when the underlying injection or withdrawal schedules change, both of the transactions no longer qualify for hedge accounting. As such, all of these above mentioned non-qualified hedges are accounted for in the Consolidated Statements of Income through mark-to-market accounting. These derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. 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.

The other significant instance where our derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 is in our Natural Gas segment. We had previously entered into natural gas collars in order to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship and contemporaneously re-designated the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to perfectly match the indices. This is a sound economic hedging strategy, however, since these instruments were out of the money at re-designation, they are considered net written options under SFAS No. 133. Therefore, the instruments do not qualify for hedge accounting upon re-designation and are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with their 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. These interim mark-to-market fluctuations do not have any cash flow impact.

Derivative Fair Value Loss (Gain)

The Derivative fair value loss (gain) on our Consolidated Statements of Income is comprised of two components:

1. the change in fair value of the ineffective portion of our cash flow hedges; and
2. the change in fair value (or, mark-to-market) of our non-qualified hedges.

	Three months ended March 31,	
	2005	2004
Hedge ineffectiveness loss		
Natural Gas segment	$ 0.2	$ —
Mark-to-market loss (gain)		
Natural Gas segment	8.2	—
Marketing segment	(1.4)	(0.2)
Derivative fair value loss (gain)	$ 7.0	$(0.2)

The changes in fair value of the Partnership's derivative financial instruments in the first quarter of 2005 compared to the corresponding period in 2004 is primarily due to sharp increases in forward natural gas and NGL prices. As a result of the Partnership's portfolio of derivative financial instruments, which is largely comprised of long-term fixed price sale agreements, the significant increase in forward commodity prices quarter over quarter has increased our obligation associated with these derivative transactions.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2004, in Item 7A of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2004.

Item 4. Controls and Procedures

The Partnership and Enbridge Inc. 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, 2005. 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, 2005, 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 7, which is incorporated herein by reference.

Item 6. Exhibits

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

3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Third Amended and Restated Agreement of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
10.1*	Amended Delegation of Control Agreement dated as of February 21, 2005.
10.2	Third Amendment to the Amended and Restated Credit Agreement, dated as of January 24, 2003 (as amended by the First Amendment, dated January 12, 2004 and the Second Amendment, dated as of April 26, 2004), by and the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on April 19, 2005).
10.3	Commercial Paper Dealer Agreement between the Company, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.1 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.4	Commercial Paper Dealer Agreement between the Company, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005, (incorporated by reference to exhibit 10.2 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.5	Commercial Paper Dealer Agreement between the Company, as Issuer, and Goldman, Sachs & Co., as Dealer, dated as of April 21, 2005, (incorporated by reference to exhibit 10.3 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.6	Commercial Paper Dealer Agreement between the Company, as Issuer, and Merrill Lynch Money Markets Inc., as Dealer, dated as of April 21, 2005, (incorporated by reference to exhibit 10.4 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.7	Issuing and Paying Agency Agreement between the Company and Deutsche Bank Trust Company Americas, dated as of April 21, 2005, (incorporated by reference to exhibit 10.5 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: May 5, 2005

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

Date: May 5, 2005

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