Available Credit

A significant source of our liquidity is provided by the commercial paper market. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. At December 31, 2006, we had $445 million in principal amount of commercial paper outstanding and could issue an additional $155 million in principal amount of commercial paper.

Our Credit Facility also provides us with another significant source of liquidity. In March 2006, we obtained an increase from $800 million to $1 billion in the aggregate commitment available to us under the terms of our Credit Facility. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2006, we had no amounts outstanding under our Credit Facility and letters of credit totaling $59.3 million. We could borrow $495.7 million under the terms of our Credit Facility at December 31, 2006, after reducing the $1 billion commitment amount by outstanding letters of credit and the principal balance of commercial paper we have outstanding. We expect to extend the capacity of our Credit Facility to approximately $1.25 to $1.5 billion in the near term, subject to the approval of the lenders that are party to our Credit Facility. At December 31, 2006, our Credit Facility remains undrawn and available to support our commercial paper program and meet our short-term liquidity needs.

Indebtedness and Other Payment Obligations

The following table presents the components of our outstanding indebtedness:

	December 31, 2006	December 31, 2005
	(in millions)	
Current maturities of long-term debt:		
Current portion of First Mortgage Notes	$ 31.0	$ 31.0
Loans from affiliates	$ 136.2	$ —
Long-term debt:		
Commercial Paper	$ 443.7	$ 329.3
Credit Facility	—	—
First Mortgage Notes	124.0	155.0
4.000% senior notes due 2009	200.0	200.0
7.900% senior notes due 2012[1]	100.0	100.0
4.750% senior notes due 2013	200.0	200.0
5.350% senior notes due 2014	200.0	200.0
5.875% senior notes due 2016	300.0	—
7.000% senior notes due 2018[1]	100.0	100.0
7.125% senior notes due 2028[1]	100.0	100.0
5.950% senior notes due 2033	200.0	200.0
6.300% senior notes due 2034	100.0	100.0
Unamortized discount	(1.6)	(1.4)
Total long-term debt	$2,066.1	$1,682.9
Loans from affiliates	$ —	$ 151.8

(1) Debt of Enbridge Energy, Limited Partnership, one of our operating subsidiaries.

Commercial Paper Program

At December 31, 2006, we had $445 million in principal amount of commercial paper outstanding, with unamortized discount of $1.3 million, at a weighted average interest rate of 5.45%, before the effect of our interest rate hedging activities. We had net borrowings of approximately $111.4 million during 2006 under our commercial paper program which include gross issuances of $3,145.4 million and gross repayments of $3,034.0 million. At December 31, 2006, we could issue an additional $155 million in principal amount of commercial paper.

Credit Facility

Our Credit Facility, as amended, is a revolving term facility that matures in April 2010. In March 2006, we obtained an increase from $800 million to $1 billion in the aggregate commitment available to us. The amounts we can 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. We pay interest on the amounts outstanding at variable rates equal to a "Base Rate" or a "Eurodollar Rate" as defined in the Credit Facility. In the case of Eurodollar Rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under the facility. We are also charged a facility fee on the entire amount of the Credit Facility, regardless of the amount drawn, which also varies depending on our credit rating. During 2006, we borrowed approximately $90 million to provide short-term financing, which we repaid the following business day.

Our Credit Facility contains restrictive covenants that require us to maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 5.25 times for twelve months through December 2006, at which time it decreases to 5.00 times, thereafter. At December 31, 2006, our interest coverage ratio was approximately 4.4 and our leverage ratio was approximately 4.6. Our Credit facility also places limitations on the debt that our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary.

At December 31, 2006, we had no balances outstanding under our Credit Facility and could borrow $495.7 million. Additionally, we have outstanding letters of credit totaling $59.3 million at December 31, 2006.

First Mortgage Notes

The First Mortgage Notes are collateralized by a first mortgage on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. We were in compliance with these covenants at December 31, 2006. We believe these issuance tests will not negatively affect our ability to access the credit markets to finance future expansion projects. Under the First Mortgage Note Agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash for the immediately preceding calendar quarter. If we repay the Notes prior to their stated maturities, the First Mortgage Note Agreements provide for the payment of a redemption premium by us.

Senior Notes

In December 2006, we issued $300.0 million in aggregate principal amount of our 5.875% Senior Notes due 2016 in a public offering, from which we received proceeds of $297.6 million, after payment of underwriting discounts and commissions and estimated offering expenses. We used the proceeds to repay a portion of our outstanding commercial paper and to finance a portion of our capital expansion projects.

We did not issue any Senior Notes during the year ended 2005; however, during 2004 we issued the following senior notes:

- In December 2004, we issued $200.0 million in aggregate principal amount of our 5.35% Senior Notes due 2014 and $100.0 million in aggregate principal amount of our 6.30% Senior Notes due 2034 in a public offering, from which we received net proceeds of $297.1 million. We used the proceeds to repay a portion of the debt outstanding under our bank Credit Facility.
- In January 2004, we issued $200.0 million in aggregate principal amount of our 4.0% Senior Notes due 2009 in a public offering, from which we received net proceeds of $198.3 million. We used the proceeds to repay a portion of the debt outstanding under our bank Credit Facility.

Enbridge Energy, Limited Partnership, our operating subsidiary that owns the Lakehead system, has $300 million of senior notes, the ("the OLP Notes") outstanding representing unsecured obligations that are structurally senior to our Senior Notes. All of the OLP Notes pay interest semi-annually and have varying maturities and terms as set forth in the table above. The OLP Notes do not contain any covenants restricting us from issuing additional indebtedness. The OLP Notes are subject to make-whole redemption rights and were issued under an indenture ("the OLP Indenture") containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with the OLP Indenture. We were in compliance with these covenants at December 31, 2006.

All of our Senior Notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our Senior Notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $300 million of OLP Notes issued by Enbridge Energy, Limited Partnership. The borrowings under our Senior Notes are non-recourse to our general partner and Enbridge Management. All of our Senior Notes pay interest semi-annually and have varying maturities and terms as presented in the table above. Our Senior Notes do not contain any covenants restricting us from issuing additional indebtedness. Our Senior Notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with our indenture agreement. We were in compliance with these covenants at December 31, 2006.

Loans from General Partner and affiliates

As of December 31, 2006 and 2005, we had $136.2 million and $151.8 million, respectively, in debt outstanding under a note to an affiliate of our general partner. This note relates to debt we assumed in connection with our acquisition of the Midcoast system in October 2002. The note matures in December 2007 and has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The note is subordinate to our Credit Facility and other senior indebtedness. For the years ended December 31, 2006 and 2005, we converted interest payable related to this note in the amount of $4.4 million and $9.7 million, respectively, into debt by increasing the principal balance of this note. Additionally, in 2006 we repaid approximately $20.0 million in principal amount of this note.

Credit Ratings

The following table reflects the ratings that have been assigned to our debt and the debt of our wholly-owned subsidiary, Enbridge Energy, Limited Partnership at December 31, 2006:

	Standard & Poor's	Moody's	Dominion Bond Rating Service
Enbridge Energy Partners, L.P.			
Outlook	Stable	Negative	Stable
Corporate	BBB	Baa2	BBB
Commercial Paper	A-2	P-2	R-2M
Medium Term Notes & Unsecured Debentures	BBB	Baa2	BBB
Enbridge Energy, Limited Partnership			
Outlook	Stable	Negative	N/A
Senior secured	BBB+	Baa1	NR
Senior unsecured	BBB	Baa1	NR

NR—No rating is available

Moody's recently affirmed our Baa2 rating but revised its outlook to negative. This reflects Moody's view that our financial profile is weaker than those of our similarly rated peers. However, Moody's believes that this weaker financial profile is offset to a degree by our low business risk profile that stems from our highly regulated and/or contracted liquids and natural gas systems and our strategy of hedging a significant portion of our commodity exposure. While our substantial organic growth capital expenditure program will place our financial profile under near term pressure until these projects are commissioned and increase our reliance on the capital markets, Moody's believes that completion of our organic growth projects should contribute to a further reduction in our overall business risk profile and that the cash flow generated by these projects as they are commissioned will strengthen our financial profile. Following the successful execution of both the construction and financing of these growth projects over the next 18 to 24 months, an improved rating outlook by Moody's is possible.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2006:

Future Minimum Commitments	2007	2008	2009	2010	2011	Thereafter	Total
				(in millions)			
Long-term debt and Loans from General Partner and affiliates	$167.2	$31.0	$231.0	$476.0	$31.0	$1,300.0	$2,236.2
Purchase commitments[1]	451.8	—	—	—	—	—	451.8
Power commitments[2]	3.2	—	—	—	—	—	3.2
Other operating leases	10.8	9.1	6.9	1.9	0.1	—	28.8
Right-of-way[3]	1.7	1.7	1.7	1.7	1.7	42.4	50.9
Product purchase obligations[4]	32.1	34.0	31.5	27.6	24.6	83.4	233.2
Service contract obligations[5]	16.4	15.6	12.5	8.3	6.2	1.8	60.8
Total	$683.2	$91.4	$283.6	$515.5	$63.6	$1,427.6	$3,064.9

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our expansion projects.

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to be approximately $1.7 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2011.

(4) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(5) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

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. Extensive volume growth in the areas served by our East Texas system and the resulting constraints in reaching primary market locations necessitates the construction of additional pipeline capacity to transport these volumes to alternate natural gas markets. Anticipated growth in Western Canadian oil sands production and the need to reach newer markets has prompted the Southern Access, Alberta Clipper and related projects associated with our liquid systems. 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. At December 31, 2006, we had approximately $451.8 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2007.

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 includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures include our capital expansion projects and other projects that 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 forecasted 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 expenditures in 2007, 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, our estimates may also change as a result of decisions made at a later date to revise the scope of a project. We anticipate our capital expenditures to approximate the following in millions:

	Total Forecasted Expenditures
Other system enhancements	$ 540
Core maintenance activities	60
Southern Access expansion	735
East Texas expansion and extension (Clarity)	230
	$1,565

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through December 31, 2006, the incremental capacity that will become available upon completion of the project and the periods we expect to complete the construction. The projected 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			
	Projected Total Cost (in billions)	Actual Expenditures through 2006 (in millions)	Storage (MBbl)	Oil (Mbpd)	Natural Gas (MMcf/d)	Expected Completion
Southern Access expansion (Lakehead)	$1.3	$110	—	400	—	In phases to early 2009
Clarity (East Texas)	0.6	325	—	—	700	In phases to late 2007
Alberta Clipper	0.8	—	—	450	—	Late 2009 to early 2010
North Dakota system expansion	0.1	11	—	30	—	Late 2007
Cushing terminal storage tanks	0.1	39	4,970	—	—	various
Griffith and Superior storage tanks.	0.1	10	1,220	—	—	Mid-2007 and Mid-2008
Natural gas connects and compression	0.1	62	—	—	—	Various
Processing and treating plant expansions	0.3	142	—	—	1,130	Various
Total	$3.4	$699	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.

Acquisitions

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

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

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the purchase and sales prices of our commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/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 December 31, 2006 for each of the indicated calendar years:

	Notional	2007	2008	2009	2010	2011	2012
			($ in millions)				
Swaps							
Natural gas[1]	301,986,269	$(32.4)	$(34.0)	$(29.2)	$(23.0)	$(19.5)	$(3.9)
NGL[2]	8,434,778	(9.3)	(5.2)	—	(1.5)	(0.6)	—
Crude[2]	1,386,571	(8.6)	(7.0)	(1.9)	(0.6)	(0.2)	—
Options—calls							
Natural gas[1]	1,826,000	(1.0)	(1.3)	(1.2)	(1.0)	(0.9)	—
Options—puts							
Natural gas[1]	2,890,000	1.0	—	—	—	—	—
Totals		$(50.3)	$(47.5)	$(32.3)	$(26.1)	$(21.2)	$(3.9)

(1) Notional amounts for natural gas are recorded in millions of British thermal units ("MMBtu").

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

Operating Activities

Net cash provided by our operating activities was $321.6 million in 2006 compared with $267.1 million in 2005. Improved operating cash flow was primarily the result of the operating income contributions of our processing assets and an increase in the deliveries on our Lakehead system. The remaining changes in cash from operating activities were due to changes in the operating assets and liabilities from declining natural gas prices in 2006, our payment of $10.2 million to settle interest rate swaps we entered to hedge the interest on the senior notes we issued in December 2006 and general timing differences in the collection on and payment of our current accounts.

Investing Activities

We used approximately $430 million more cash in our investing activities during 2006 than in 2005. The approximate $153 million decrease in expenditures for acquisitions from 2005 was more than offset by the $520 million increase in our investments in property, plant and equipment during 2006. The increase in our capital expenditures during 2006 is directly attributable to our shift in strategy to more organic growth projects to expand the service capability of our existing systems. Also contributing to the increase in the cash used in our investing activities in 2006 from 2005 are approximately $105 million of proceeds we received in 2005 in connection with the sale of gathering and processing assets located on our East and South Texas systems. The proceeds of this sale were partially offset by our payment of $16.3 million to settle derivatives in connection with the sale of these assets. We expect that cash flows used in our investing activities will remain at high levels throughout the periods we are performing extensive expansions to our Lakehead and East Texas systems.

Financing Activities

Net cash provided by our financing activities was $640.2 million in 2006, compared with $181.5 million in 2005. In 2006, we increased the level of our financing activities to obtain permanent capital for financing our organic growth projects. In August 2006, we issued approximately 10.8 million of our Class C units to our general partner and an institutional investor at $46.00 per unit for proceeds of approximately $500 million. Additionally, our general partner contributed an additional $10 million to maintain its two percent general partner interest. Also in December 2006, we issued $300 million in principal amount of our senior notes and received proceeds of approximately $297.6 million after payment of underwriting commissions and issuance costs. Also contributing to our financing activities was approximately $111.4 million of net borrowings under our commercial paper program which include gross issuances of $3,145.4 million and gross repayments of $3,034.0 million. These increases in sources of cash flow from financing activities are partially offset by a greater amount of distributions to our partners resulting from more outstanding limited partner units and payments we made on the First Mortgage Notes and on an affiliate loan.

During 2006, cash distributions to partners increased to $227.4 million from $210.6 million in 2005 due to:

- An increase in the number of units outstanding; and
- An increase in the general partner incentive distributions, as a result of the increased cash distributions to our common unitholders.

Cash Distributions

We make quarterly distributions to our General Partner and the holders of our limited partner units in an amount equal to our "available cash." As defined in our partnership agreement, "available cash" represents for any calendar quarter, the sum of all of our cash receipts plus net reductions to reserves less all of our cash disbursements and net changes to reserves. We retain reserves to provide for the proper conduct of our business, to stabilize distributions to our unitholders and the General Partner and, as necessary, to comply with the terms of any of our agreements or obligations. Enbridge Management, as the delegate of the General Partner under a delegation of control agreement, computes the amount of our available cash.

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B common units, the number of i-units owned by Enbridge Management and the percentage of total units in us owned by Enbridge Management increases automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the sum of Enbridge Management's shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per limited partner unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

Until August 15, 2009, in lieu of cash distributions, the holders of our Class C units will receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we pay to the holders of our Class A and Class B common units, which we collectively refer to as common units. The number of additional Class C units we will issue is determined by dividing the quarterly cash distribution per unit we pay on our common units by the average market price of a Class A common unit as listed on the New York Stock Exchange for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. As a result, the number of Class C units and the percentage of our total units owned by holders of the Class C units will increase automatically under the provisions of our partnership agreement. The cash equivalent amount of the additional Class C units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

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

For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units and Class C units that are issued when a distribution of cash is made to the General Partner and owners of common units is treated as distribution of available cash, even though the i-unit holder and holders of our Class C units will not receive cash. We retain the cash for use in our operations to finance a portion of our capital expansion projects. During 2006, we distributed a total of 969,200 i-units through quarterly distributions to Enbridge Management, compared with 802,539 in 2005. Additionally, we distributed a total of 200,587 Class C units to the holders of our Class C units. We retained $54.7 million in 2006 related to the i-unit and Class C unit distributions, compared with $41.5 million in 2005.

We expect our annual cash distribution rate for fiscal year 2007 to remain consistent with the declared annual distribution per unit rate of $3.70 for the years ended December 31, 2006 and 2005. We expect that all cash distributions will be paid out of operating cash flows over the long term; however, from time to time, we may temporarily borrow under our Credit Facility or issue additional commercial paper for the purpose of paying cash distributions until the full impact of assets being developed on operations is realized.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements.

Subsequent Events

Distribution to Partners

On January 26, 2007, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2007. The distribution was paid to unitholders of record as of February 6, 2007, of our available cash of $80.0 million at December 31, 2006, or $0.925 per limited partner unit. Of this distribution, $57.6 million was paid in cash, $11.7 million was distributed in i-units to our i-unitholder, $10.2 million was distributed in Class C units to the holders of our Class C units and $0.5 million was retained from the General Partner in respect of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

Line 14 Leaks

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 less than $1 million. 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 throughput. 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 minimized as the line was repaired and returned to service in less than two days. We are investigating this incident and will record costs associated with the repair and cleanup as such amounts are determined.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our selection and application of accounting policies is an important process that has developed as our business activities have evolved and as new accounting pronouncements have been issued. Accounting decisions generally involve an interpretation of existing accounting principles and the use of judgment in applying those principles to the specific circumstances existing in our business. We make every effort to comply with all applicable accounting principles and believe the proper implementation and consistent application of these principles is critical. However, not all situations we encounter are specifically addressed in the accounting literature. In such cases, we must use our best judgment to implement accounting policies that clearly and accurately present the substance of these situations. We accomplish this by analyzing similar situations and the accounting guidance governing them and consulting with experts about the appropriate interpretation and application of the accounting literature to these situations.

In addition to the above, certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for our estimates is historical experience, consultation with experts and other sources we believe to be reliable. While we believe our estimates are appropriate, actual results can and often do differ from these estimates. Any effect on our business, financial position, results of operations and cash flows resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

We believe our critical accounting policies and estimates discussed in the following paragraphs address the more significant judgments and estimates we use in the preparation of our consolidated financial statements. Each of these areas involves complex situations and a high degree of judgment either in the application and interpretation of existing accounting literature or in the development of estimates that affect our consolidated financial statements. Our management has discussed the development and selection of the critical accounting policies and estimates related to the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent liabilities with the Audit, Finance & Risk Committee of Enbridge Management's board of directors.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectibility is reasonably assured. For our natural gas and marketing businesses, we must estimate our current month revenue and cost of natural gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each period reported. We believe that the assumptions underlying these estimates will not be significantly different from the actual amounts due to the routine nature of these estimates and the stability of our processes.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* or SFAS No. 71, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. 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. Examples of enhancement expenditures include costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving a major segment of the pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion.

Regulatory guidance issued by the FERC requires us to expense certain costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under this guidance, beginning in January 2006, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We adopted this guidance prospectively in January 2006 for all our pipeline systems. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition continue to be capitalized. We have historically capitalized initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects. Beginning January 2006, costs of this nature are expensed as incurred which is consistent with industry practice and the regulatory guidance issued by the FERC. However, we continue to capitalize initial construction hydrostatic testing cost and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also capitalized are certain costs such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred. Our adoption of the regulatory guidance did not significantly affect our financial position, results of operations or cash flows.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of their estimated useful lives or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we will recognize a gain or loss in our Consolidated Statements of Income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these regular assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Income.

Assessment of Recoverability of Goodwill and Intangibles

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time we determine that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, we make estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with our most recent five-year plan, which we use to manage the business.

Preparation of forecast information for use in our five-year plan involves significant judgment. Actual results can, and often do, differ from the projections and assumptions we make in preparing these forecasts. These changes can have a negative impact on our estimates of impairment, which could result in charges to income. In addition, further changes in the economic and business environment can affect our original and ongoing assessments of potential impairment.

Other intangible assets consist of customer contracts for the purchase and sale of natural gas, and natural gas supply opportunities, which we amortize on a straight-line basis over the weighted average useful life of the underlying assets, which is the period over which the asset is expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of the intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. If there are changes to any of our estimates and assumptions, actual results may differ.

Asset Retirement Obligations

We record a liability for the fair value of our asset retirement obligations, or ARO, on a discounted basis, in the period in which the liability is incurred. Typically we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for asset retirement obligations when assets are taken out of service or otherwise abandoned.

The provisions of Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47") require us to recognize a liability and related asset, consistent with SFAS No. 143, for the fair value of conditional asset retirement obligations that we can reasonably estimate. FIN 47 also provides specific guidance regarding when an asset retirement obligation is reasonably estimable including when sufficient information is available to apply an expected present value technique. Our implementation of FIN 47 did not have a material impact effect on our consolidated financial statements.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate an abandonment retirement obligation cost. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's intent, or the asset's estimated economic life. Useful lives of most pipeline systems are primarily derived from available supply resources and the ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the ARO. Indeterminate ARO costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). To reduce 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 and fix the interest rate on our variable rate debt.

The accounting treatment for our derivative financial instruments is determined by the guidance of SFAS No. 133 and is dependent on each instrument's intended use, how it is designated and the extent to which the derivative financial instrument is effective in reducing the risk that it is intended to hedge. To qualify for hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Derivative financial instruments qualifying for hedge accounting treatment that we use can generally be divided into two categories: 1) cash flow hedges, or 2) fair value hedges. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions. We enter into fair value hedges to reduce the risk of changes in the value of a recognized asset or liability. Cash flow and fair value hedges are considered highly effective if they are able to substantially offset (i.e., more than 80 percent) the changes in cash flow or fair value of the risk that is being hedged. The extent to which a derivative financial instrument designated as a hedge does not offset the changes in cash flow or fair value of the risk being hedged is considered ineffective. At inception and on an ongoing basis we assess whether the derivative financial instruments we use in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items.

All of our derivative financial instruments are recorded in our Consolidated Financial Statements at fair market value as current and long-term assets or liabilities on a net basis by counterparty and are adjusted each period for changes in the fair market value. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Derivative financial instruments that we designate and qualify as cash flow or fair value hedges under the requirements of SFAS No. 133, receive hedge accounting treatment for the effective portion of the derivative financial instrument. Under hedge accounting, any unrealized gain or loss in fair market value of the effective portion of a derivative financial instrument designated as a cash flow hedge is recorded as an asset or liability with an offset deferred in Accumulated other comprehensive income ("AOCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges of forecasted commodity purchases and sales are included in Cost of natural gas and cash flow hedges of forecasted interest payments are included in Interest expense on our Consolidated Statements of Income in the period the hedged transaction occurs. Under hedge accounting, the realized and unrealized gain or loss in the fair market value of a derivative financial instrument designated as a fair value hedge is recorded as an asset or a liability with the offset recorded in our Consolidated Statements of Income as a component of Cost of natural gas for fair value hedges of our commodities and as a component of interest expense for fair value hedges of our indebtedness both of which are offset by the changes in the fair market value of the underlying hedged item.

Under the guidance of SFAS No. 133, the changes in fair market value, both realized and unrealized gains and losses, of derivative financial instruments that 1) do not qualify for hedge accounting, 2) are not designated as hedges and 3) are ineffective, are recognized each period in our Consolidated Statements of Income. These changes in fair market value are recognized as a component of Cost of natural gas for our commodity derivative financial instruments and as a component of interest expense for derivative financial instruments of our interest rates. We refer to the accounting treatment for derivative financial instruments that do not qualify for hedge accounting as mark-to-market accounting. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the non cash earnings volatility that arises under mark-to-market accounting treatment.

Our cash flow is only affected to the extent the actual derivative contract is settled by 1) making or receiving a payment to/from the counterparty; or 2) by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the physical transaction that underlies the derivative financial instrument occurs.

Gains and losses that we have 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.

One of the primary factors that can affect our operating results each period is the price assumptions we use to value our derivative financial instruments. To the extent that these derivative financial instruments are ineffective or do not qualify for hedge accounting treatment under the requirements of SFAS No. 133, they are accounted for using the mark-to-market method of accounting and any change in the fair market value is reflected in our Consolidated Statements of Income as a component of Cost of natural gas or Interest expense, depending on whether the derivative financial instrument relates to a commodity or interest rate. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our consolidated financial statements change quarterly as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Commitments, Contingencies and Environmental Liabilities

We accrue reserves for contingent liabilities, including environmental remediation and clean-up costs, when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors, and include estimates of associated legal costs. These estimates also consider prior experience remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances and any revisions are reflected in our earnings in the period in which they are reasonably determinable. We evaluate recoveries from insurance coverage separately from our liability and, when recovery is reasonably assured, we record and report an asset separately from the associated liability in our financial statements. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial cost and future liabilities.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Both internal and external legal counsel evaluate our potential exposure to adverse outcomes. When a range of probable loss can be estimated, we accrue the most likely amount, or at least the minimum of the range of probable loss. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to review our estimates, income may be affected.

Crude Oil Over/Short Balance and Crude Oil Measurement Gains/Losses

Crude oil over/short balance and crude oil measurement gains/losses are inherent in the transportation of crude oil due to evaporation, measurement differences and blending of commodities in transit in addition to other factors. We estimate our crude oil measurement gains/losses and our crude oil over/short balance based on mathematical calculations and physical measurements, which include assumptions about the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the system. A material change in these assumptions may result in a change to the carrying value of our crude oil over/short balance or revision of our crude oil measurement gain/loss estimates. We include the crude oil measurement gains/losses in our operating and administrative expenses on our Consolidated Statements of Income and the crude oil over/short balance in Accounts payable and other in the Consolidated Statements of Financial Position if the balance is a liability and in Inventory if the balance is in an asset position.

Operational Balancing Agreements and Natural Gas Imbalances

We record payables and receivables associated with our natural gas pipeline operational balancing agreements and natural gas imbalances monthly when a customer delivers more or less natural gas into our pipelines than they remove. These balances are either settled on a cash basis or are carried by the pipelines and shippers on an in-kind basis. We primarily estimate the value of the imbalances at month-end spot prices based on published third-party indices for the locations where the imbalances are derived using the best available third party and internal volume information. If there is a change to these estimates and assumptions, actual results may differ.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Fair Value Measurements

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

Accounting for Registration Payment Arrangements

In December 2006, the FASB issued FASB Staff Position FSP EITF 00-19-2, *Accounting for Registration Payment Arrangements*. This FASB Staff Position, or FSP, specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with FASB Statement No. 5, *Accounting for Contingencies*. This FSP also requires certain disclosures regarding registration payment arrangements and liabilities recorded for such purposes. This FSP is immediately effective for registration payment arrangements entered into or modified after December 21, 2006. The guidance of this FSP is effective for fiscal years beginning after December 15, 2006, and interim periods within those fiscal years for registration payment arrangements entered into prior to December 21, 2006. This FSP requires adoption by reporting a change in accounting principle through a cumulative-effect adjustment to the opening balance of our partners' capital accounts as of the first interim period of the year in which this FSP is initially applied. We do not expect our adoption of this FSP to materially affect our financial position, results of operations or cash flows.

Staff Accounting Bulletin No. 108

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108. This Bulletin requires a "dual approach" for quantifications of errors using both a method that focuses on the income statement impact, including the cumulative effect of prior years' misstatements, and a method that focuses on the period-end balance sheet. We adopted SAB No. 108 as of December 31, 2006. The adoption of this Bulletin did not have a material impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

INTEREST RATE RISK

We utilize both fixed and variable interest rate debt, and are exposed to market risk resulting from the variable interest rates on our Credit Facility and the frequent changes in interest rates when we re-issue maturing commercial paper. To the extent that we frequently issue and re-issue commercial paper at short-term interest rates and have amounts drawn under our credit facilities at floating rates of interest, our earnings and cash flows are exposed to changes in interest rates. This exposure is managed through periodically refinancing commercial paper and floating-rate bank debt with long-term fixed rate debt and through the use of interest rate derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in U.S. dollars. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments.

The following table presents the principal cash flows and related weighted average interest rates by expected maturity dates along with the carrying values and fair values of our third-party debt obligations as of December 31, 2006 and 2005.

	December 31, 2006									December 31, 2005	
	Average Interest Rate	Expected Fiscal Year of Maturity of Carrying Amounts									
		2007	2008	2009	2010	2011	Thereafter	Total	Fair Value	Carrying Amount	Fair Value
	(dollars in millions)										
Liabilities											
Fixed Rate:											
First Mortgage Notes . .	9.150%	$31.0	$31.0	$ 31.0	$ 31.0	$31.0	$ —	$155.0	$169.5	$186.0	$207.9
Senior notes due 2009 . .	4.000%	—	—	200.0	—	—	—	200.0	194.2	199.9	193.0
Senior notes due 2012 . .	7.900%	—	—	—	—	—	99.9	99.9	110.5	99.9	113.8
Senior notes due 2013 . .	4.750%	—	—	—	—	—	199.8	199.8	188.6	199.8	190.8
Senior notes due 2014 . .	5.350%	—	—	—	—	—	199.9	199.9	193.0	199.9	196.7
Senior notes due 2016 . .	5.875%	—	—	—	—	—	299.7	299.7	297.4	—	—
Senior notes due 2018 . .	7.000%	—	—	—	—	—	99.8	99.8	107.9	99.8	111.4
Senior notes due 2028 . .	7.125%	—	—	—	—	—	99.8	99.8	108.9	99.8	113.0
Senior notes due 2033 . .	5.950%	—	—	—	—	—	199.7	199.7	186.2	199.7	193.1
Senior notes due 2034 . .	6.300%	—	—	—	—	—	99.8	99.8	97.1	99.8	100.8
Variable Rate:											
Commercial paper . . .	5.450%	—	—	—	443.7	—	—	443.7	443.7	329.3	329.3
Credit Facility	n/a	—	—	—	—	—	—	—	—	—	—

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. 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 interest rates. 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.

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations which are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at December 31, 2006.

	December 31, 2006									December 31, 2005		
		Expected Fiscal Year of Maturity of Notional Amounts										
	Notional Amount	2007	2008	2009	2010	2011	Thereafter	Fair Value Asset	Fair Value Liability	Notional Amount	Fair Value Asset	Fair Value Liability
	(dollars in millions)											
Interest Rate Derivatives												
Interest Rate Swaps:												
Floating to Fixed	$ 525.0	$ 1.5	$ 0.5	$ 0.4	$ 0.6	$ 0.6	$ 0.7	$4.3	$ —	$ 275.0	$3.1	$—
Average Pay Rate	4.41%	4.81%	4.35%	4.35%	4.35%	4.35%	4.35%	—	—	3.72%	—	—
Average Receive Rate	LIBOR	LIBOR	LIBOR	LIBOR	LIBOR	LIBOR	LIBOR	—	—	LIBOR	—	—
Fixed to Floating	$ 125.0	$ (0.5)	$ (0.1)	$ (0.1)	$ (0.2)	$ (0.2)	$ (0.2)	$ —	$(1.3)	$ 125.0	$0.6	$—
Average Pay Rate	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	—	—	LIBOR-0.21%	—	—
Average Receive Rate	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	—	—	4.75%	—	—
Treasury Locks:												
Floating to Fixed	$ 200.0	$ 2.8	$ —	$ —	$ —	$ —	$ —	$2.8	$ —	$ —	$ —	$—
Average Pay Rate	4.68%	4.68%	—	—	—	—	—	—	—	—	—	—
Average Receive Rate	30YR-UST	30YR-UST	—	—	—	—	—	—	—	—	—	—
Interest Rate Collars:												
Calls	$ 100.0	$ 0.1	$ —	$ —	$ —	$ —	$ —	$0.1	$ —	$ —	$ —	$—
Average Pay Rate	5.50%	5.50%	5.50%	—	—	—	—	—	—	—	—	—
Average Receive Rate	LIBOR	LIBOR	LIBOR	—	—	—	—	—	—	—	—	—
Puts	$ 100.0	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$—
Average Pay Rate	4.17%	4.17%	4.17%	—	—	—	—	—	—	—	—	—
Average Receive Rate	LIBOR	LIBOR	LIBOR	—	—	—	—	—	—	—	—	—

(1) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

(2) UST refers to United States Treasury notes.

Our floating to fixed rate interest rate swaps maturing in 2007 qualify for hedge accounting treatment as set forth in SFAS No. 133 and have been designated cash flow hedges of interest payments on $400 million of our variable rate indebtedness. Similarly, our treasury locks maturing in 2007 qualify for hedge accounting treatment pursuant to the requirements of SFAS No. 133 and have been designated as cash flow hedges of future interest payments on the first $200 million of an anticipated debt issuance. Additionally, our interest rate collars qualify for hedge accounting treatment as per SFAS No. 133 and have been designated as cash flow hedges of interest payments on $100 million of our variable rate indebtedness. As such, the fair value of these derivative financial instruments is recorded as assets or liabilities on our Consolidated Statements of Financial Position with the changes in fair value recorded as corresponding increases or decreases in AOCI.

The floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 have not been designated as cash flow or fair value hedges under SFAS No. 133 and, as a result, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense.

COMMODITY PRICE RISK

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

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

	At December 31, 2006						At December 31, 2005	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2007								
Swaps								
Receive variable/pay fixed	Natural gas	67,928,435	$ 6.39	$ 7.56	$ 8.1	$ (86.7)	$ 112.0	$ (1.0)
	NGL	99,645	38.52	43.65	—	(0.5)	—	—
Receive fixed/pay variable	Natural gas	67,584,962	7.32	6.63	79.8	(33.0)	0.5	(170.0)
	NGL	4,296,415	38.18	40.28	14.4	(23.2)	—	(22.5)
	Crude oil	388,680	42.05	64.96	—	(8.6)	—	(7.9)
Receive variable/pay variable	Natural gas	42,790,661	6.54	6.55	3.1	(3.7)	0.7	(0.1)
Options								
Calls (written)	Natural gas	365,000	7.00	4.31	—	(1.0)	—	(2.0)
Puts	Natural gas	1,429,000	6.79	5.97	1.0	—	—	—
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	17,000,112	7.63	7.36	9.5	(5.1)	18.5	—
Receive fixed/pay variable	Natural gas	24,537,303	6.30	8.07	3.6	(44.1)	—	(66.3)
	NGL	1,680,453	37.28	40.67	2.5	(7.7)	—	(7.2)
	Crude oil	337,241	45.16	67.49	—	(7.0)	—	(5.2)
Receive variable/pay variable	Natural gas	19,577,541	8.28	8.16	2.5	(0.4)	1.0	—
Options								
Calls (written)	Natural gas	366,000	8.06	4.31	—	(1.3)	—	(1.7)
Puts	Natural gas	366,000	8.06	3.40	—	—	—	—

	At December 31, 2006						At December 31, 2005	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural gas	4,902,720	7.44	7.26	2.9	(2.1)	—	—
Receive fixed/pay variable	Natural gas	12,865,240	5.15	7.86	0.7	(31.5)	—	(34.5)
	NGL	1,543,950	40.75	40.78	1.4	(1.4)	—	(0.6)
	Crude oil	264,625	59.09	67.13	—	(1.9)	—	(1.0)
Receive variable/pay variable	Natural gas	16,277,500	8.03	7.98	1.4	(0.6)	1.1	—
Options								
Calls (written)	Natural gas	365,000	7.83	4.31	—	(1.2)	—	(1.4)
Puts	Natural gas	365,000	7.83	3.40	—	—	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural gas	1,511,295	7.31	5.58	2.5	(0.3)	—	—
Receive fixed/pay variable	Natural gas	9,490,000	4.11	7.36	0.2	(26.1)	0.1	(25.9)
	NGL	584,000	32.68	35.78	—	(1.5)	—	(0.4)
	Crude oil	213,525	63.00	66.46	—	(0.6)	—	(0.1)
Receive variable/pay variable	Natural gas	7,200,000	8.17	8.05	0.8	(0.1)	—	—
Options								
Calls (written)	Natural gas	365,000	7.42	4.31	—	(1.0)	—	(1.1)
Puts	Natural gas	365,000	7.42	3.40	—	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural gas	730,000	7.02	3.57	2.0	—	—	—
Receive fixed/pay variable	Natural gas	7,952,500	3.63	7.02	—	(21.5)	—	(21.3)
	NGL	230,315	31.70	34.87	—	(0.6)	—	—
	Crude oil	182,500	64.30	65.83	—	(0.2)	—	—
Options								
Calls (written)	Natural gas	365,000	7.02	4.31	—	(0.9)	—	(0.9)
Puts	Natural gas	365,000	7.02	3.40	—	—	—	—
Contracts maturing after 2012								
Swaps								
Receive variable/pay fixed	Natural gas	182,000	7.56	3.57	0.6	—	—	—
Receive fixed/pay variable	Natural gas	1,456,000	3.57	7.56	—	(4.5)	—	(4.8)

(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 December 31, 2006 and December 31, 2005, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive, 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 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 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 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.

Discontinuance of Hedge Accounting

In 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery locations for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, in 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of Income from AOCI. Going forward, the derivative financial instruments for which hedge accounting has been discontinued are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed out in 2005.

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)	December 31, 2006	December 31, 2005	December 31, 2004
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ (1.9)	$ (2.5)	$(1.1)
Non-qualified hedges	1.8	(5.6)	—
Marketing			
Non-qualified hedges	64.5	(41.3)	(2.1)
Discontinued hedges	—	(9.0)	—
Derivative fair value gains (losses)	$ 64.4	$(58.4)	$(3.2)

De-designation and Settlement of Derivatives

In connection with the sale of assets in December 2005, as discussed in Note 3 to the Consolidated Financial Statements beginning on page F-1 of this report, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that qualified for and were designated as cash flow hedges of forecasted sales of 273 Bpd of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bpd of NGLs through 2007.

Derivative Positions

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

	December 31, 2006	December 31, 2005
	(in millions)	
Receivables, trade and other	$ 7.2	$ 5.8
Other assets, net	11.0	4.2
Accounts payable and other	(57.2)	(129.2)
Other long-term liabilities	(136.4)	(243.0)
	$(175.4)	$(362.2)

The decrease in our obligation associated with derivative activities is primarily due to the decline in current and forward natural gas prices at December 31, 2006 in relation to current and forward natural gas prices at December 31, 2005. 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. We regularly enter into treasury locks to hedge the interest on anticipated issuances of indebtedness. The settlement of a treasury lock can result in the retention of unrecognized gains or losses in AOCI that are amortized to interest expense over the life of the related debt issuance. We paid $10.2 million in December 2006, to settle treasury locks in connection with the issuance of $300 million in principal amount of our senior notes. The $10.2 million will be amortized from AOCI to interest expense over the 10-year life of the senior notes.

Also included in AOCI are unrecognized losses of approximately $4.8 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions 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 years ended December 31, 2006, 2005 and 2004, we reclassified unrealized losses of $78.3 million, $33.8 million and $12.6 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. We estimate that approximately $57.6 million of AOCI representing unrealized net losses on cash flow hedging activities at December 31, 2006, will be reclassified to earnings during the next twelve months.

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 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the notes thereto and the independent registered public accounting firm's report thereon, and unaudited supplementary information, appear beginning on page F-2 of this report, and are incorporated by reference. Reference should be made to the "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

We 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 December 31, 2006. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. No changes in our internal control over financial reporting were made during the three months ended December 31, 2006, that would materially affect our internal control over financial reporting.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Report on Internal Control Over Financial Reporting

Management of Enbridge Energy Partners, L.P. and its consolidated subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f).

The Partnership's internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting includes policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Partnership;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with the authorization of the Partnership's management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

The Partnership's internal control over financial reporting may not prevent or detect all misstatements because of its inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or deterioration in the degree of compliance with our policies and procedures.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006, based on the framework established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2006.

Management's assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report beginning on page F-2.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The Partnership is a limited partnership and has no officers or directors of its own. Set forth below is certain information concerning the directors and executive officers of the General Partner and of Enbridge Management as the delegate of the General Partner under a Delegation of Control Agreement among the Partnership, the General Partner and Enbridge Management. All directors of the General Partner are elected annually and may be removed by Enbridge Pipelines, as the sole stockholder of the General Partner. All directors of Enbridge Management were elected and may be removed by the General Partner, as the sole holder of Enbridge Management's voting shares. All officers of the General Partner and Enbridge Management serve at the discretion of the respective boards of directors of the General Partner and Enbridge Management. All directors and officers of the General Partner hold identical positions in Enbridge Management.

Name	Age	Position
J.A. Connelly	60	Director
E.C. Hambrook	69	Director
M.O. Hesse	64	Director
G.K. Petty	65	Director
S.J.J. Letwin	51	Managing Director and Director
T.L. McGill	52	President and Director
J.R. Bird	57	Executive Vice President—Liquids Pipelines and Director
L.A. Zupan	51	Vice President—Liquids Pipelines Operations
M.A. Maki	42	Vice President—Finance
R.L. Adams	42	Vice President—Operations and Technologies
J.M. Gerez	50	Vice President—Liquids Pipelines Project Management & Engineering
J.A. Holder	49	Vice President—Liquids Pipelines Support Services
J.A. Loiacono	44	Vice President—Commercial Activities
D.V. Krenz	55	Vice President
V.D. Yu	40	Treasurer
J.N. Rose	39	Assistant Treasurer
S.J. Neyland	39	Controller
E.C. Kaitson	50	Assistant Secretary
B.A. Stevenson	51	Corporate Secretary

J.A. Connelly was elected a director of the General Partner and Enbridge Management in January 2003 and serves as the Chairman of the Audit, Finance & Risk Committee. Mr. Connelly served as Executive Vice President, Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001. Mr. Connelly is a business consultant providing executive management consulting services.

E.C. Hambrook was elected a director of the General Partner and Enbridge Management in January 1992 and serves on the Audit, Finance & Risk Committee. Mr. Hambrook serves as Chairman of the board of directors of the General Partner and Enbridge Management. Mr. Hambrook has served as President of Hambrook Resources, Inc. since its inception in 1991. Hambrook Resources, Inc. is a real estate investment, marketing and sales company.

M.O. Hesse was elected a director of the General Partner and Enbridge Management in March 2003 and serves as a member of the Audit, Finance & Risk Committee. Ms. Hesse was President and CEO of Hesse Gas Company from 1990 through 2003. She served as Chairman of the U.S. Federal Energy Regulatory Commission from 1986 to 1989. Ms. Hesse also served as Senior Vice President, First Chicago Corporation and Assistant Secretary for Management and Administration, U.S. Department of Energy. She currently serves as a director of Arizona Public Service Company, Pinnacle West Capital Corporation, and Terra Industries, Inc.

G.K. Petty was elected a director of the General Partner and Enbridge Management in February 2001 and serves on the Audit, Finance & Risk Committee. Mr. Petty has served as a director of Enbridge since January 2001. Mr. Petty served as President and Chief Executive Officer of Telus Corporation, a Canadian telecommunications company, from November 1994 to November 1999. Mr. Petty is a business consultant providing executive management consulting services to the telecommunications industry.

S.J.J. Letwin was elected Managing Director of the General Partner and Enbridge Management in May 2006. Prior to his election he served Enbridge, the indirect parent of our General Partner, as Group Vice President, Gas Strategy & Corporate Development since April 2003; prior thereto he served Enbridge as Group Vice President, Distribution & Services since September 2000.

T. L. McGill was elected President of the General Partner and Enbridge Management in May 2006. Prior to that he served as Vice President, Commercial Activity and Business Development of the General Partner and Enbridge Management since April 2002 and Chief Operating Officer since July 2004. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

J.R. Bird served as a director of the General Partner and Enbridge Management from September 2000 to January 2003 and was reelected as a Director in October 2003. He has also served as Executive Vice President, Liquids Pipelines of the General Partner and Enbridge Management since May 2006, and holds similar responsibilities with Enbridge. Prior to that Mr. Bird served as a Group Vice President, Liquids Transportation from May 2001 and in other senior leadership positions with Enbridge from August 1997.

L.A. Zupan was elected Vice President, Liquids Pipelines Operations of the General Partner and Enbridge Management in July 2004, and holds similar responsibilities with Enbridge. Prior to that he has served as Vice President, Development & Services for Enbridge Pipelines since 2000 and prior to that as Director, Information Technology since November 1999.

M.A. Maki was elected Vice President, Finance of the General Partner and Enbridge Management in July 2002. Prior to that time, he served as Controller of the General Partner and Enbridge Management since June 2001, and prior to that, as Controller of Enbridge Pipelines since September 1999.

R.L. Adams was elected Vice President, Operations and Technologies of the General Partner and Enbridge Management in April 2003. Prior to his current position, he was Director of Technology & Operations for the General Partner and Enbridge Management since 2001, and Director of Field Operations and Technical Services and Director of Commercial Activities for Ocensa/Enbridge in Bogota, Colombia from 1997 to 2001.

J.M. Gerez was elected Vice President, Liquids Pipelines Project Management and Engineering, of the General Partner and Enbridge Management in May 2006, and holds similar responsibilities with Enbridge. Prior to that he was Vice President Operations with OCENSA, an Enbridge affiliate in Colombia from 2000 to May 2006.

J. A. Holder was elected Vice President, Liquids Pipelines Support Services of the General Partner in April 2006, and holds similar responsibilities with Enbridge. Prior to that she served as Vice President, Market Services for Enbridge since December 2004 and prior to that as Vice President, Operations for Enbridge Gas Distribution since May 2001.

J.A. Loiacono was elected Vice President, Commercial Activities, of the General Partner and Enbridge Management in July 2006. Prior to that, he was Director of Commercial Activities for the General Partner and Enbridge Management from April 2003 and commenced employment with Midcoast Energy Resources in February 2000 as an Asset Optimizer.

D.V. Krenz was elected Vice President of the General Partner and Enbridge Management in January 2005. Prior to that, he was President of Shell Gas Transmission, LLC (previously Shell Gas Pipelines Co.) from March 1996 to December 2004.

V. D. Yu was elected as Treasurer of the General Partner and Enbridge Management in July 2005 and is also Vice President, Enterprise Risk of Enbridge. Since July 2002 he was Director Financial Management at Enbridge and previously Manager, Capital Markets and Risk Management since October 2000.

J. N. Rose was appointed as Assistant Treasurer of the General Partner and Enbridge Management in July 2005 and is also a Manager, Corporate Finance of Enbridge, a position he has held since April 2004. Prior to that Mr. Rose was a Vice President with Citigroup Global Corporate and Investment Bank from 2001 to 2004.

S.J. Neyland, was elected Controller of the General Partner and Enbridge Management effective September 2006. Prior to his election he served as Controller, Natural gas since January 2005, Assistant Controller from May 2004 to January 2005, and in other managerial roles in Finance and Accounting from December 2001 to May 2004. Prior to that Mr. Neyland was Controller of Koch Midstream Services from 1999 to 2001.

E.C. Kaitson was elected Assistant Secretary of the General Partner and Enbridge Management in July 2004. He served as Corporate Secretary of the General Partner and Enbridge Management from October 2001 to July 2004. He also currently serves as Associate General Counsel of Enbridge. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until Enbridge acquired it on May 11, 2001.

B.A. Stevenson was elected Corporate Secretary of the General Partner and Enbridge Management in July 2004. Between 2000 and 2004 Mr. Stevenson held management positions with Reliant Energy, Inc. and Arthur Andersen LLP. Prior to that Mr. Stevenson was General Counsel & Corporate Secretary of Alberta Natural Gas Company Ltd, a Canadian gas processing and transmission company, that was acquired by TransCanada Pipelines.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors, executive officers and 10% beneficial owners to file with the SEC reports of ownership and changes in ownership of our equity securities and to furnish us with copies of all reports filed. To our knowledge, based solely on a review of the copies of reports furnished to us and written representations that no other reports were required, the officers, directors, and greater than 10% beneficial owners complied with all applicable filing requirements of Section 16(a) of the Exchange Act during the year, except that Mr. G.K. Petty filed a late Form 4 on March 20, 2006, for transactions that occurred on March 13, 2006.

GOVERNANCE MATTERS

We are a "controlled company," as that term is used in NYSE Rule 303A, because all of our voting shares are owned by the General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

The NYSE listing standards require our CEO to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. Accordingly, this certification was provided as required to the NYSE on March 17, 2006.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to our senior financial officers, including the principal executive officer, principal financial officer and principal accounting officer of Enbridge Management. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. We intend to post on our website any amendments to or waivers of our Code of Ethics for Senior Financial Officers. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

We also have a Statement of Business Conduct applicable to all of our employees, officers and directors. A copy of the Statement of Business Conduct is available on our website at *www.enbridgepartners.com*. We intend to post on our website any amendments to or waivers of our Statement of Business Conduct. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston TX 77002.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how the Board should function and the Board's position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at *www.enbridgepartners.com*. We intend to post on our website any amendments to our Corporate Governance Guidelines. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston TX 77002.

AUDIT, FINANCE & RISK COMMITTEE

Enbridge Management has an Audit, Finance & Risk Committee (the "Audit Committee") comprised of four board members who are independent as the term is used in Section 10A of the Exchange Act of 1934, as amended. None of these members is relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are J.A. Connelly, E.C. Hambrook, M.O. Hesse, and G.K. Petty. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the report of the independent registered public accounting firm. The Audit Committee also reviews the scope and quality, including the independence and objectivity of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the board of directors.

The charter of the Audit Committee is available on our website at *www.enbridgepartners.com*. The charter of the Audit Committee complies with the listing standards of the NYSE currently applicable to us.

Enbridge Management's board of directors has determined that J.A. Connelly, E.C. Hambrook and M.O. Hesse qualify as "Audit Committee financial experts" as defined in Item 407(d)(ii) of

SEC Regulation S-K. Each of the members of the Audit, Finance and Risk Committee is independent as defined by Section 303A of the listing standards of the NYSE.

Mr. Petty also serves on the Audit Committees of the General Partner, Enbridge Management, Fuel Cell Energy, Inc. and of Enbridge Inc. In compliance with the provisions of the Audit, Finance & Risk Committee Charter, the board of directors of the General Partner and of Enbridge Management have determined that Mr. Petty's simultaneous service on such audit committees would not impair his ability to effectively serve on the Audit, Finance & Risk Committee.

Enbridge Management's Audit Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our Audit Committee may do so by writing in care of Chairman, Audit Committee, c/o Enbridge Energy Management, L.L.C., 1100 Louisiana, Suite 3300, Houston TX 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. J.A. Connelly or E.C. Hambrook serve as the presiding director at those executive sessions. Persons wishing to communicate with the Company's independent directors may do so by writing in care of Chairman, Board of Directors, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and we do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We obtain managerial, administrative and operational services from our general partner and Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

The compensation policies and philosophy of Enbridge govern the types and amount of compensation granted each of the Named Executive Officers, or NEOs. Since these policies and philosophy are those of Enbridge, we refer you to a discussion of those items as set forth in the Executive Compensation section of the Enbridge "Management Information Circular" on the Enbridge website at www.enbridge.com. The Enbridge "Management Information Circular" is produced by Enbridge pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Securities Exchange Act of 1934, as amended; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our general partner.

The boards of directors of Enbridge Management and our General Partner do not have separate compensation committees, nor do they have responsibility for approving the elements of compensation presented in the tables which follow this discussion. The boards of directors of Enbridge Management and our general partner do have responsibility for evaluating and determining the reasonableness of the total amount we are charged for managerial, administrative and operational support, including compensation of the NEOs, provided by Enbridge and its affiliates, including our general partner.

All U.S.-domiciled employees of Enbridge are directly employed by its subsidiary, Enbridge Employee Services, Inc., which we refer to as EES. In connection with our annual budget process, we calculate an average "Budgeted Allocation Rate," which represents an estimated average of the percentage of time for each of our NEOs that will be spent on our business during the succeeding year. Those estimates are revised each year based on historical experience. The average Budgeted Allocation Rate was 87% for 2006 and has been set at 84% for 2007. EES's salary costs are allocated to us based on the percentage of time spent by EES employees on our behalf compared with the total time of all EES employees. We are allocated a portion of the equity-based compensation expense as determined in accordance with U.S. GAAP. Pension expenses of EES (other than expenses under Enbridge's nonqualified supplemental pension plan for U.S.-domiciled employees, which we refer to as the SPP) are allocated to us based on the proportion that the total headcount of EES employees assigned to us bears to the total headcount of EES. For this purpose, an employee of EES is deemed to be assigned to us if he or she works on assets owned by the Partnership. Pension expenses of EES attributable to the SPP are allocated to us based upon the average Budgeted Allocation Rate. EES allocates to us that portion of its compensation expense for Enbridge's Short Term Incentive Plan, a non-equity performance-based incentive plan, equal to the total salaries of employees who perform work for us multiplied by the average Budgeted Allocation Rate divided by EES' total salary expense.

As we are a partnership and not a corporation for U.S. federal income tax purposes, we are not subject to the executive compensation tax deductible limitations of Internal Revenue Code §162(m). Accordingly, none of the compensation paid to our NEOs is subject to limitation. The compensation of our Named Executive Officers included in the tables below is established by a committee of the board of directors of Enbridge. We have included in the following tables, the full amount of compensation and related benefits provided for the NEOs for 2006, together with the approximate amount of compensation cost allocated to us for the year ended December 31, 2006.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards[1] ($)	Option Awards[2] ($)	Non-Equity Incentive Plan Compensation[3] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation[4] ($)	Total ($)	Approximate Amount Allocated to Enbridge Energy Partners, L.P. ($)
S.J.J. Letwin[5] . . . . . . Managing Director *(Principal Executive Officer)*	2006	$ 457,257	$—	$ 108,600	$ 68,362	$ 450,000	$ 208,000	$ 156,165	$ 1,448,384	$ —
D.C. Tutcher . . . . President—Retired *(Former Principal Executive Officer)*	2006	145,441	—	—	—	90,000	200,000	39,971	475,412	400,000
T.L. McGill . . . . President	2006	290,000	—	38,535	24,055	200,000	103,000	33,225	688,815	585,000
J. R. Bird[6] . . . . Executive Vice President—Liquids Pipelines	2006	419,937	—	98,090	61,488	440,878	512,000	50,806	1,583,199	190,000
M.A. Maki . . . . Vice President—Finance *(Principal Financial Officer)*	2006	212,500	—	22,187	14,131	140,000	71,000	30,842	490,660	420,000
R.L. Adams . . . . Vice President—Operations and Technology	2006	189,375	—	19,852	12,731	117,000	55,000	29,661	423,619	360,000
J.A. Loiacono. . . . . . . Vice President—Commercial Activities	2006	181,458	—	—	11,330	121,000	41,000	23,428	378,216	320,000

(1) The expense associated with Performance Stock Units (PSUs) is reflected in this column and is measured based on the number of respective units granted, the percentage vested (33%) and the current market price of the Company's shares in Canadian dollars, or CAD, of $39.73. The expense has been converted to United States dollars, or USD, using the average exchange rate during 2006 of $1.1341 CAD = $1 USD. The PSUs were granted on January 1, 2006.

(2) The annual expense is determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Scholes option pricing model with the following assumptions:

- 8 years expected term;
- 19% expected volatility;
- 3.23% expected dividend yield; and
- 4.16% risk free interest rate

The fair value of options granted as computed using these assumptions is expensed over the shorter of the vesting period for the options (generally 4 years) and the period to early retirement eligibility. The exercise price was $36.47 CAD for all option grants in 2006, which have been converted to United States dollars using the exchange rate on the grant date of $1.1548 CAD =$1 USD. The fair value of all grants on the grant date was $6.28 CAD and have been converted to USD using the average exchange rate during 2006 of $1.1341 CAD = $1 USD, representing the exchange rate for the period during which the expense was recognized.

(3) Non-equity incentive plan compensation represents awards that are paid in February for amounts that are earned in the immediately preceding fiscal year under the Enbridge Short Term Incentive Plan, or STIP. The Enbridge STIP is a performance-based plan where measurement metrics are established at the beginning of each fiscal year that promote the achievement of financial, safety, corporate governance and individual goals.

(4) The table which follows labeled "All Other Compensation" sets forth the elements comprising the amounts presented in this column.

(5) Mr. Letwin relocated to the United States on May 1, 2006, and became Managing Director of our general partner and Enbridge Management concurrent with the retirement of Mr. Tutcher. Mr. Letwin is also an executive officer of Enbridge with responsibility for other Enbridge operations in addition to those of our general partner, Enbridge Management, and us, that he assumed in May 2006. We have included the full amount of Mr. Letwin's compensation in the summary compensation table. However, we were not charged the cost of Mr. Letwin's compensation for the period from January 1, 2006 through December 31, 2006, since the allocation to us of compensation to Mr. Letwin was not contemplated in our budget. As a result, Mr. Letwin's compensation was borne by other Enbridge affiliates. In the future, we will be charged for an allocable portion of the compensation paid to Mr. Letwin primarily based on the time that he spends overseeing our operations. We used a weighted average exchange rate of $1.1519 CAD = $1.0 USD to convert the compensation costs to USD for Mr. Letwin, which represents the weighted average exchange rate for the period from May 1, 2006 through December 31, 2006. The costs associated with the PSU's and options Mr. Letwin was granted in 2006 were borne by Enbridge and other affiliates where he is also an officer because the grants occurred prior to his becoming managing director of our general partner and Enbridge Management.

(6) Mr. Bird is also an executive officer of Enbridge with responsibility for other affiliates of Enbridge in addition to those for our general partner and Enbridge Management. Mr. Bird is compensated by affiliates of Enbridge in CAD which we have converted to USD using the weighted average exchange rate from January 1, 2006 through December 31, 2006 of $1.1341 CAD = $1.0 USD. The costs associated with the PSU's and options Mr. Bird was granted in 2006 were borne by Enbridge and other affiliates where he is also an officer. We are allocated a portion of the remaining elements of Mr. Bird's compensation based on the approximate percentage of time he devotes to us and Enbridge Management.

ALL OTHER COMPENSATION
(year ended December 31, 2006)

Name	Year	Flexible Benefits[(1)]	401(k) Matching Contribution[(2)]	Relocation Allowance	Mortgage Interest Payments	Other Benefits[(3)]	Total
S.J.J. Letwin	2006	35,169	11,000	77,500	25,701	6,795	156,165
D.C. Tutcher	2006	30,000	7,137	—	—	2,834	39,971
T.L. McGill	2006	20,000	11,000	—	—	2,225	33,225
J.R. Bird	2006	48,482	—	—	—	2,324	50,806
M.A. Maki	2006	20,000	10,625	—	—	217	30,842
R.L. Adams	2006	20,000	9,469	—	—	192	29,661
J.A. Loiacono	2006	14,167	9,073	—	—	188	23,428

(1) Flexible benefits are provided to our NEOs based on their family status and base salary. For our NEOs that are domiciled in the United States, the flexible benefits can be (a) used to purchase additional benefits such as extended health, dental, disability and life insurance on the same terms as are available to all employees; or (b) paid as additional compensation. NEOs domiciled in Canada may also defer a portion of the flexible benefits to be applied as contributions to the Enbridge Stock Purchase and Savings Plan.

(2) Our NEOs that are domiciled in the United States and participate in the Enbridge Employee Services, Inc. Savings Plan (the "401(k) Plan") may contribute up to 50 percent of their base salary which is matched up to 5 percent by Enbridge. Both individual and matching contributions are subject to limits established by the Internal Revenue Service. Enbridge contributions are used to purchase Enbridge shares at market value and employee contributions may be used to purchase Enbridge shares or 22 designated funds.

(3) Other benefits include professional financial services, term life insurance premiums, parking, and home security and internet services.

We do not maintain any compensation plans for the benefit of the NEOs under which equity interests in Enbridge Management or the Partnership may be awarded. However, Enbridge allocates to us the compensation expense it recognizes under FAS 123(R) in connection with recording the fair value of its restricted stock units and outstanding stock options granted to certain of our officers, including the NEOs. The costs we are charged with respect to option grants represents a portion of the costs determined in accordance with U.S. GAAP.

The restricted stock units are granted to the NEOs pursuant to the Enbridge Inc. Restricted Stock Unit Plan (2006) and stock options are granted pursuant to the Enbridge Incentive Stock Option Plan. Awards under these plans provide long-term incentive and are administered by the Human Resources & Compensation Committee of Enbridge. The restricted stock units and stock option grants are denominated in Canadian dollars. The following two tables set forth information concerning restricted stock units and stock options outstanding at December 31, 2006, and the number of awards vested and exercised during the year ended December 31, 2006, by each of the NEOs:

GRANTS OF PLAN-BASED AWARDS

Name (a)	Plan Name[1] (b)	Approval Date (b)	Grant Date (c)	Estimated Future Payouts Under non-Equity Incentive Plan Awards[4]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]			All Other Stock Awards: Number of Shares of Stock or Units (#) (j)	All Other Option Awards: Number of Securities Underlying Options[3] (#) (k)	Exercise or Base Price of Option Awards[3] ($/Sh) (l)	Grant Date Fair Value of Stock and Option Awards[2][3] ($) (j)
				Threshold ($) (d)	Target ($) (e)	Maximum ($) (f)	Threshold (#) (g)	Target (#) (h)	Maximum (#) (i)				
S.J.J. Letwin	PSUP	1-Feb-06	1-Jan-06	—	—	—	372	9,300	18,600	—	—	—	290,379
	ISOP	1-Feb-06	13-Feb-06	—	—	—	—	—	—	—	53,700	31.58	292,901
	STIP	1-Feb-06	28-Feb-06	—	232,500	465,000	—	—	—	—	—	—	—
D.C. Tutcher[5].	STIP	1-Feb-06	28-Feb-06	—	58,333	116,667	—	—	—	—	—	—	—
T.L. McGill.	PSUP	1-Feb-06	1-Jan-06	—	—	—	132	3,300	6,600	—	—	—	103,038
	ISOP	1-Feb-06	13-Feb-06	—	—	—	—	—	—	—	18,900	31.58	103,088
	STIP	1-Feb-06	28-Feb-06	—	120,000	240,000	—	—	—	—	—	—	—
J.R. Bird.	PSUP	1-Feb-06	1-Jan-06	—	—	—	336	8,400	16,800	—	—	—	262,278
	ISOP	1-Feb-06	13-Feb-06	—	—	—	—	—	—	—	48,300	31.58	263,447
	STIP	1-Feb-06	28-Feb-06	—	213,826	427,652	—	—	—	—	—	—	—
M.A. Maki	PSUP	1-Feb-06	1-Jan-06	—	—	—	76	1,900	3,800	—	—	—	59,325
	ISOP	1-Feb-06	13-Feb-06	—	—	—	—	—	—	—	11,100	31.58	60,544
	STIP	1-Feb-06	28-Feb-06	—	84,000	168,000	—	—	—	—	—	—	—
R.L. Adams.	PSUP	1-Feb-06	1-Jan-06	—	—	—	68	1,700	3,400	—	—	—	53,080
	ISOP	1-Feb-06	13-Feb-06	—	—	—	—	—	—	—	10,000	31.58	54,544
	STIP	1-Feb-06	28-Feb-06	—	67,375	134,750	—	—	—	—	—	—	—
J.A. Loiacono	ISOP	1-Feb-06	13-Feb-06	—	—	—	—	—	—	—	8,900	31.58	48,544
	STIP	1-Feb-06	28-Feb-06	—	67,375	134,750	—	—	—	—	—	—	—

(1) The abbreviated plan names are defined as follows:

a. PSUP refers to the Enbridge Performance Stock Unit Plan, an equity-based incentive plan.

b. ISOP refers to the Enbridge Incentive Stock Option Plan, a qualified stock option plan.

c. STIP refers to the Enbridge Short Term Incentive Plan, a non-equity performance-based incentive plan.

(2) Our NEOs are eligible to receive annual grants of Performance Stock Units, or PSUs, under the Performance Stock Unit Plan, or PSUP, an equity-based, long-term incentive plan, administered by a committee of the board of directors of Enbridge. The initial value of each of these PSUs is equivalent to the market value of one Enbridge share on the grant date. The initial PSUs granted are increased for quarterly dividends paid during the three-year period on an Enbridge share. Awards under the PSUP are paid out in cash at the end of a three-year performance cycle based on: (1) the market value of an Enbridge share at the end of the three-year period; and (2) the total shareholder return for Enbridge over a three-year period in relation to a peer group of companies established in advance by a committee of the board of directors of Enbridge. Payments under the PSUP may be increased up to 200 percent of the original award when Enbridge outperforms its peer group. If Enbridge fails to meet threshold performance levels, no payments are made under the PSUP. Enbridge does not issue any shares in connection with the PSUP.

The threshold at which PSUs are issued represents 4 percent of the number of PSUs initially granted and is the lowest level at which PSUs will be issued based on the performance criteria discussed above. The target level at which PSUs are issued represents 100 percent of the number of PSUs initially granted and attainment of the established performance criteria. The maximum level at which PSUs may be issued is 200 percent of the number of PSUs initially granted and may occur when Enbridge exceeds the established performance criteria.

PSUs vest at the end of a three year performance period that begins on January 1 of the year granted and during the term the PSUs are outstanding, a liability and expense are recorded by Enbridge based on the number of PSUs outstanding and the current market price of an Enbridge share. The grant date fair value for each PSU granted to each of our NEOs was $36.13 CAD, representing the weighted average closing price of one Enbridge share as quoted on the Toronto Stock Exchange for the 30 days immediately preceding the start of the performance period that began on January 1, 2006. We have converted the grant date fair value for each of the PSU grants made from CAD to USD using an exchange rate of $1.1571 CAD per $1.00 USD, representing the noon buying rate in New York for transfers of CAD on January 3, 2006, the first business day of the performance period that began on January 1, 2006.

(3) The Enbridge Incentive Stock Option Plan (2002) is administered by a committee of the Enbridge board of directors and if an option is issued during a trading blackout period, the exercise price of an option grant is determined as the weighted average trading price of an Enbridge share on the Toronto Stock Exchange for the three trading days immediately prior to the effective date of the option. In the event an option grant is issued during a period a trading blackout is not in effect, the exercise price of the option grant is equal to the last reported sales price on the Toronto Stock Exchange for the day immediately preceding the grant date. During 2006, each of the NEOs received grants of Enbridge incentive stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The

exercise price of the incentive stock options at the time of grant was $36.47 CAD which has been converted into USD using an exchange rate of $1.1548 CAD per $1 USD, representing the noon buying rate in New York for transfers of CAD on the grant date of February 13, 2006.

The amounts included as the grant date fair value for the 2006 incentive stock option awards represent the amount determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Scholes option pricing model with the following assumptions:

- 8 years expected term;
- 19% expected volatility;
- 3.23% expected dividend yield; and
- 4.16% risk free interest rate

The fair value of options granted as computed using these assumptions is $6.28 CAD which has been converted to USD using an exchange rate of $1.1548 CAD = $1 USD which equates to a grant date fair value of $5.45 USD per option granted. The grant date fair value is expensed over the shorter of the vesting period for the options (generally 4 years) and the period to early retirement eligibility.

(4) The estimated future payouts under the Enbridge STIP are determined for the indicated fiscal year, based upon achievement of performance goals established at the beginning of the fiscal year for each of the NEOs. The payouts earned under the STIP for each fiscal year are generally paid to the NEO on the last business day of February of the year following the fiscal year in which the payout is earned. The performance goals include pre-determined financial, safety, corporate governance and operational goals that are aligned with the business objectives for Enbridge and the business unit(s) to which the NEOs are assigned, in addition to individual performance objectives. Based upon the level achieved in meeting the pre-determined objectives, a multiple is determined that can vary from a low of zero, if the level of achievement is significantly below the stated objectives, to a high of two, if the level of achievement significantly exceeds the stated objective, with the mid-point or target representing achievement of 100 percent of the pre-established goals. The multiple is then applied to the bonus level, represented as a percentage of base salary, for each NEO. The STIP targets for each NEO expressed as a percentage of salary for 2006 is as follows:

	Threshold	Target	Maximum
S.J.J. Letwin	—	50%	100%
D.C. Tutcher	—	50%	100%
T.L. McGill	—	40%	80%
J.R. Bird	—	50%	100%
M.A. Maki	—	35%	70%
R.L. Adams	—	35%	70%
J.A. Loiacono	—	35%	70%

(5) Upon Mr. Tutcher's retirement effective May 1, 2006, 67,500 of unvested incentive stock options were vested pursuant to the terms of the ISOP and became exercisable until June 2, 2006, and 56,667 performance stock options were cancelled. In addition, Mr. Tutcher's PSUs granted in 2004 and 2005 continue to receive dividends and will be paid out on a pro rata basis within 60 day following completion of the performance period.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable [1][2] (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date[1] (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[3] (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
S.J.J. Letwin	—	40,000[2]	—	14.63	16-Sep-10	—	—	9,759	337,228
	—	20,000	—	13.69	6-Feb-13	—	—	10,508	363,114
	—	22,000	—	19.30	4-Feb-14	—	—	9,597	331,622
	13,100	39,300	—	25.49	3-Feb-15				
	—	53,700	—	31.58	13-Feb-16				
D.C. Tutcher.	143,333[2]	—	—	14.63	2-May-09	—	—	7,740	267,444
						—	—	7,541	260,574
T.L. McGill.	34,800	11,600	—	13.69	6-Feb-13	—	—	3,063	105,847
	20,000	20,000	—	19.30	4-Feb-14	—	—	3,405	117,672
	5,100	15,300	—	25.49	3-Feb-15				
	—	18,900	—	31.58	13-Feb-16				
J.R. Bird.	160,000	40,000[2]	—	14.63	16-Sep-10	—	—	7,401	255,750
	20,000	20,000	—	13.69	6-Feb-13	—	—	8,296	286,669
	16,700	16,700	—	19.30	4-Feb-14	—	—	8,668	299,529
	10,350	31,050	—	25.49	3-Feb-15				
	—	48,300	—	31.58	13-Feb-16				
M.A. Maki	7,500	—	—	12.43	21-Feb-11	—	—	2,276	78,650
	16,000	—	—	13.68	5-Feb-12	—	—	1,961	67,751
	25,050	8,350	—	13.69	6-Feb-13				
	15,000	15,000	—	19.30	4-Feb-14				
	2,850	8,550	—	25.49	3-Feb-15				
	—	11,100	—	31.58	13-Feb-16				
R.L. Adams	750	3,750	—	13.69	6-Feb-13	—	—	2,148	74,240
	5,000	10,000	—	19.30	4-Feb-14	—	—	1,754	60,619
	2,700	8,100	—	25.49	3-Feb-15				
	—	10,000	—	31.58	13-Feb-16				
J.A. Loiacono	1,700	—	—	13.04	1-Jul-10	—	—	—	—
	5,000	—	—	13.68	5-Feb-12				
	1,800	1,200	—	13.69	6-Feb-13				
	4,000	4,000	—	19.30	4-Feb-14				
	2,500	7,500	—	25.49	3-Feb-15				
	—	8,900	—	31.58	13-Feb-16				

(1) Each incentive stock option award has a ten year term and vests pro rata as to one-fourth of the option award beginning on the first anniversary of the grant date thus, the vesting dates for each of the option awards in this table can be calculated accordingly. As an example, for Mr. Letwin's grant that expires on February 6, 2013, the grant date would be ten years prior or February 6, 2003 and as a result, the remaining unexercisable amounts become fully vested on February 6, 2007 representing four years following the grant date.

(2) Performance-based stock options, or PBSOs, which were provided to certain of our NEOs on September 16, 2002, that are similar to the incentive stock options, except that the quantity that become exercisable are subject to both time and performance requirements. PBSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge Share for each option held when the specified time and performance conditions are met. The PBSOs became exercisable, as to 50 percent of the grant, when the price of an Enbridge Share exceeded $30.50 CAD for 20 consecutive trading days during the period September 16, 2002 to September 16, 2007, and became exercisable as to 100 percent when the price of an Enbridge share exceeded $35.50 CAD for 20 consecutive trading days during the same period. As a result of achieving the established performance criteria, the initial five year term of the options was extended to eight years expiring on September 16, 2010. In addition to the performance hurdles, the PBSOs are also time vested 20% annually over 5 years. As of December 31, 2006, 80 percent of the PBSOs had vested and were exercisable and the remaining 20 percent will vest and become exercisable on September 16, 2007.

(3) The unearned shares, units or other rights that have not vested under stock awards represent PSUs for which the performance criteria discussed in footnote number 2 of the Grants of Plan-Based Awards table have not been achieved. The PSUs become vested upon achieving the established performance criteria as set forth in the aforementioned footnote.

OPTION EXERCISES AND STOCK VESTED

Name	Option Awards: Number of Shares Acquired on Exercise (#)	Option Awards: Value Realized on Exercise ($)	Stock Awards: Number of Shares Acquired on Vesting (#)	Stock Awards: Value Realized on Vesting ($)
S.J.J. Letwin	172,000	2,058,154	—	—
D.C. Tutcher	589,694	7,458,233	—	—
T.L. McGill	11,500	165,319	—	—
J.R. Bird	200,000	3,159,793	—	—
M.A. Maki	2,500	35,911	—	—
R.L. Adams	6,300	86,592	—	—
J.A. Loiacono	7,300	119,164	—	—

Pension Plan

Enbridge sponsors two basic pension plans, the Retirement Plan for Employees' Annuity Plan ("EI RPP") and the Enbridge Employee Services, Inc. Employees' Annuity Plan ("QPP"), which provide defined pension benefits and cover employees in Canada and the United States, respectively. Both plans are non-contributory. The Company also sponsors supplemental nonqualified retirement plans in both Canada ("EI SPP") and the United States ("US SPP"), which provide pension benefits for the NEOs in excess of the tax-qualified plans' limits. We collectively refer to the EI RPP, the QPP, the EI SPP and the US SPP as the "Pension Plans." Retirement benefits under the Pension Plans are based on the employees' years of service and final average remuneration with an offset for Social Security benefits. These benefits are partially indexed to inflation after a named executive officer's retirement.

For service prior to January 1, 2000, the Pension Plans provide a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 1.6 percent of the average of the participant's highest annual salary during three consecutive years out of the last ten years of credited service multiplied by (b) the number of credited years of service. The pension is offset, after age 65, by 50 percent of the participant's Social Security benefit, prorated by years in which the participant has both credited service and Social Security coverage. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50 percent of the annual increase in the consumer price index.

For service after December 31, 1999, the Pension Plans provide for senior management employees, including the NEOs, a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 2 percent of the sum of (i) the average of the participant's highest annual base salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant's three highest annual performance bonus periods, represented in each period by 50 percent of the actual bonus paid, in respect of the last five years of credited service, multiplied by (b) the number of credited years of service. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50 percent of the annual increase in the consumer price index.

The table illustrates the total annual pension entitlements assuming the eligibility requirements for an unreduced pension have been satisfied. Plan benefits that exceed maximum pension rules applicable to registered plan benefits are paid from the Enbridge supplemental pension plans. Other trusteed pension plans, with varying contribution formulae and benefits, cover the balance of employees.

Mr. Bird accumulated pension credits equal to 2.0% for each year of service from his date of employment until January 1, 2000 and 3.26% for each year of service thereafter to his sixtieth birthday. Mr. Letwin was granted six additional years of credited service on his employment date based on the pension formula applicable for service prior to January 1, 2000. Mr. Tutcher accumulated pension credits equal to 4.0% for each year of service to his tenth anniversary of employment with the Corporation.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number Of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
S.J.J. Letwin	EI RPP	7.08	169,000	—
	EI SPP	13.08	1,274,000	—
	QPP	0.67	24,000	—
	USSPP	0.67	62,000	—
D.C. Tutcher	US QPP	4.76	208,000	8,000
	US SPP	4.92	1,200,000	41,000
T.L. McGill	US QPP	4.83	72,000	—
	US SPP	4.83	280,000	—
J.R. Bird	EI RPP	11.92	372,000	—
	EI SPP	11.92	2,191,000	—
M.A. Maki	EI RPP	1.92	31,000	—
	EI SPP	1.92	29,000	—
	US QPP	18.40	392,000	—
	US SPP	5.50	74,000	—
R.L. Adams	US QPP	20.20	395,000	—
	US SPP	5.50	63,000	—
J.A. Loiacono	US QPP	4.50	46,000	—
	US SPP	3.75	80,000	—

Employment and Severance Agreements

Enbridge has employment and severance agreements in place with each of Stephen J. J. Letwin, Managing Director and Chief Executive Officer of Enbridge Management and the General Partner, and J. Richard Bird, Executive Vice President—Liquids Pipelines of Enbridge Management and the General Partner. The agreements took effect on April 14, 2003 and were amended effective June 24, 2004. The agreements continue in effect until the earlier of (i) the applicable executive's voluntary retirement in accordance with the retirement policies established for senior employees of Enbridge, (ii) such executive's voluntary resignation, other than a voluntary resignation within 90 days after a "constructive dismissal" (as defined in the agreements) or within one year following a change of control of Enbridge, (iii) termination based on death or disability of such executive, or (iv) termination of such executive's employment by Enbridge.

The agreements provide that Enbridge will pay severance benefits to each of Mr. Letwin and Mr. Bird if (i) his employment is involuntarily terminated without cause or because of his disability, (ii) he elects to terminate his employment within 60 days of the first anniversary of the occurrence of a change of control of Enbridge, or (iii) he elects to terminate his employment within 60 days following constructive dismissal.

In each such instance, and subject to the terms of the agreements, Enbridge will pay to the applicable executive the following:

(a) A lump sum payment equal to two times the sum of: (i) twelve times the gross monthly salary paid to him in the last full month of employment and (ii) the average of the last two years of the Enbridge Short Term Incentive Plan (STIP) awards paid to him;

(b) A lump sum payment equal to two times the cash value of the last annual flex benefit credit allowance provided to him under Enbridge's flexible benefit program, unless he continues to be covered through Enbridge's annuitant benefit program or the benefits program of another employer;

(c) A lump sum payment equal to the value of his annual incentive bonus to be paid for the calendar year in which termination occurs, pro rated based upon the number of days of his employment in such year;

(d) A lump sum payment equal to the value of all of his accrued and unpaid annual vacation pay to the date of his termination;

(e) A lump sum payment equal to two times the cash value of the last annual flexible perquisite allowance provided to him under Enbridge's flexible perquisites program, less any amounts paid to him but unearned by virtue of such termination of employment; and

(f) Payment for financial counseling or career counseling assistance in an amount up to a maximum of $10,000.

The agreements also provide that each of Mr. Letwin and Mr. Bird are entitled to certain benefits, including two years of additional service added to the service already accrued at the date of his termination under the Enbridge defined benefit pension plan and supplemental benefit pension plan and cash payment of certain non-vested options, if any, that are cancelled under the Incentive Stock Option Plan (ISOP) as a consequence of termination of his employment. In the case of options granted pursuant to the ISOP, the payment is calculated based on the in-the-money value of the applicable executive's non-vested option at the date of his termination.

According to the agreements, a "change of control" means:

- the sale to a person or acquisition by a person not affiliated with Enbridge or its subsidiaries of net assets of Enbridge or its subsidiaries having a value greater than 50% of the fair market value of the net assets of Enbridge and its subsidiaries determined on a consolidated basis prior to such sale whether such sale or acquisition occurs by way of reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise;

- any change in the holding, direct or indirect, of shares of Enbridge by a person not affiliated with Enbridge as a result of which such person, or a group of persons, or persons acting in concert, or persons associated or affiliated with any such person or group within the meaning of the Securities Act (Alberta), are in a position to exercise effective control of Enbridge whether such change in the holding of such shares occurs by way of takeover bid, reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise; and for the purposes of this Agreement, a person or group of persons holding shares or other securities in excess of the number which, directly or following conversion thereof, would entitle the holders thereof to cast 20% or more of the votes attaching to all shares of Enbridge which, directly or following conversion of the convertible securities forming part of the holdings of the person or group of persons noted above, may be cast to elect directors of Enbridge shall be deemed, other than a person holding such shares or other securities in the ordinary course of business as an investment manager who is not using such holding to exercise effective control, to be in a position to exercise effective control of Enbridge;

- any reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction involving Enbridge where shareholders of Enbridge immediately prior to such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction hold less than 60% of the shares of Enbridge or of the continuing corporation following completion of such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, transfer, sale or other transaction;
- Enbridge ceases to be a distributing corporation as that term is defined in the Canada Business Corporations Act;
- any event or transaction which Enbridge board of directors, in its discretion, deems to be a change of control; or
- Enbridge board of directors is no longer comprised of a majority of incumbent directors, who are defined as directors who were directors immediately prior to the occurrence of the transaction, elections or appointments giving rise to a change of control and any successor to an incumbent director who was recommended for election at a meeting of Enbridge shareholders, or elected or appointed to succeed any incumbent director, by the affirmative vote of the directors, which affirmative vote includes a majority of the incumbent directors then on the board of directors.

Each of Mr. Letwin and Mr. Bird is subject during his employment (and for 2 years thereafter with regard to disclosure of confidential information) to restrictions on (i) any practice or business in competition with Enbridge or its affiliates and (ii) disclosure of the confidential information of Enbridge or its affiliates.

In the event of involuntary termination without cause or because of disability or voluntary termination within 60 days of the first anniversary of the occurrence of a change of control of Enbridge or within 60 days following constructive dismissal, Enbridge would owe approximately $6 million and $11 million to Mr. Letwin and Mr. Bird, respectively. Such amounts assume that termination was effective as of December 31, 2006, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to each of Mr. Letwin and Mr. Bird upon his termination under such circumstances. The actual amounts to be paid out can only be determined at the time of such executive's separation from Enbridge.

Director Compensation

As a partnership, we are managed by Enbridge Management, as the delegee of Enbridge Energy Company, Inc., our general partner. The boards of directors of Enbridge Management and our general partner, which are comprised of the same persons, perform for us the functions of a board of directors of a business corporation. We are allocated 100 percent of the director compensation of these board members. Enbridge employees who are members of the boards of directors of the General Partner or Enbridge Management do not receive any additional compensation for serving in those capacities.

As of January 1, 2006, the Director Compensation Plan was amended to increase the annual retainer to $75,000 and additional meeting fees were eliminated. The retainers paid to directors serving as the chairman of the boards and chairman of the audit committees will remain at current levels. The out of state travel fee will be increased to $1,500 per meeting. As part of this change to the Director Compensation Plan, the directors voted to amend the Corporate Governance Guidelines to incorporate an expectation that independent directors will hold a personal investment in either or both of Enbridge Energy Partners, L.P. or Enbridge Management, of at least two times the annual board retainer (i.e., 2 × $75,000 = $150,000). Directors would be expected to achieve the foregoing level of share ownership by the later of January 1, 2011 or five years from the date they became a director.

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
J.A. Connelly. . . . *Audit Committee Chairman*	83,500	—	—	—	—	—	83,500
E.C. Hambrook . *Chairman of the Boards*	106,000	—	—	—	—	—	106,000
M.O. Hesse	82,000	—	—	—	—	—	82,000
G.K. Petty	81,000	—	—	—	—	—	81,000

The General Partner indemnifies each director for actions associated with being a director to the full extent permitted under Delaware law and maintains errors and omissions insurance.

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Enbridge Energy Management, L.L.C., as delegate of the general partner of Enbridge Energy Partners, L.P., has reviewed and discussed the Compensation Discussion and Analysis section of this report with management of Enbridge Energy Partners, L.P. and, based on that review and discussions, has recommended that the Compensation Discussion and Analysis be included in report.

/s/ STEPHEN J.J. LETWIN
Stephen J.J. Letwin
Managing Director and Director

/s/ T.L. MCGILL
T.L. McGill
President and Director

/s/ J.R. BIRD
J.R. Bird
Director

/s/ J.A. CONNELLY
J.A. Connelly
Director

/s/ E.C. HAMBROOK
E.C. Hambrook
Director

/s/ M.O. HESSE
M.O. Hesse
Director

/s/ G.K. PETTY
G.K. Petty
Director

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 22, 2007, with respect to persons known to us to be the beneficial owners of more than 5% of any class of the Partnership's units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent Of Class
Enbridge Energy Management, L.L.C. 1100 Louisiana, Suite 3300 Houston, TX 77002	i-units	12,902,676	100.0
Enbridge Energy Company, Inc. 1100 Louisiana, Suite 3300 Houston, TX 77002	Class B common units	3,912,750	100.0
	Class C units	5,632,936	50.0
CDP Infrastructures Fund G.P. 1000 place Jean-Paul-Riopelle Montreal, Québec H2Z 2B3	Class C units	5,632,936	50.0

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 15, 2007, with respect to each class of our units and the Listed Shares of Enbridge Management beneficially owned by the NEOs, directors and nominees for director of the General Partner and all executive officers, directors and nominees for director of the Partnership as a group:

	Enbridge Energy Partners, L.P.			Enbridge Energy Management, L.L.C.		
Name	Title of Class	Amount and Nature of Beneficial Ownership(1)	Percent Of Class	Title of Class	Number of Shares(1)	Percent Of Class
J.A. Connelly	Class A common units	5,000	*	Listed Shares	—	—
E.C. Hambrook	Class A common units	2,000	*	Listed Shares	1,282.30	*
M.O. Hesse	Class A common units	—	—	Listed Shares	7,152.60	*
G.K. Petty	Class A common units	2,617	*	Listed Shares	967.70	*
S.J.J. Letwin	Class A common units	15,000	*	Listed Shares	—	—
T.L. McGill	Class A common units	—	—	Listed Shares	1,364.70	*
J.R. Bird(2)	Class A common units	—	—	Listed Shares	10,752.20	*
L.A. Zupan	Class A common units	—	—	Listed Shares	—	—
M.A. Maki	Class A common units	—	—	Listed Shares	—	—
R.L. Adams	Class A common units	—	—	Listed Shares	—	—
J.M. Gerez	Class A common units	—	—	Listed Shares	—	—
J.A. Holder	Class A common units	—	—	Listed Shares	—	—
J.A. Loiacono	Class A common units	—	—	Listed Shares	—	—
D.V. Krenz	Class A common units	—	—	Listed Shares	—	—
V.D. Yu	Class A common units	—	—	Listed Shares	—	—
J.N. Rose	Class A common units	—	—	Listed Shares	—	—
S.J. Neyland	Class A common units	—	—	Listed Shares	—	—
E.C. Kaitson	Class A common units	—	—	Listed Shares	—	—
B.A. Stevenson	Class A common units	—	—	Listed Shares	—	—
All Officers, directors and nominees as a group 17 persons)	Class A common units	24,617	*	Listed Shares	21,519.50	*

* Less than 1%.

(1) Each beneficial owner has sole voting and investment power with respect to all the units or shares attributed to him/her.

(2) All of such shares held are pledged as security for a debt.

Item 13. Certain Relationships and Related Transactions, and Director Independence

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

In August 2006 we sold approximately 5.4 million of our Class C units, representing a new class of limited partner interest, to our general partner and 5.4 million Class C units to an institutional investor for a purchase price of $46.00 per unit for a total of approximately $500 million. Additionally, our general partner contributed approximately $10 million to maintain its two percent general partner interest.

At December 31, 2006, our general partner had the following ownership interest in us:

	Quantity	Effective Ownership %
Direct ownership		
Class B common units representing limited partner interest	3,912,750	4.9%
Class C units representing limited partner interest	5,535,076	7.0%
General Partner interest	—	2.0%
Indirect ownership		
Enbridge Management shares (Listed and Voting)	2,182,771	2.8%
Total effective ownership	11,630,597	16.7%

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

At December 31, 2006, Enbridge Management owned 12,674,148 i-units, representing a 16.0% limited partner interest in us. The i-units are a separate class of our limited partner interests. All of our i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management's limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the Partnership Agreement and the provisions of Enbridge Management's limited liability company agreement, the number of outstanding Enbridge Management shares and the number of our i-units will at all times be equal.

CASH DISTRIBUTIONS

As discussed in "Part II, Item 7", we make quarterly cash distributions of all of our available cash to our General Partner and the holders of our common units. The holders of our i-units and Class C units receive in-kind distributions under the Partnership Agreement. Our General Partner receives incremental incentive cash distributions on the portion of cash distributions that exceed certain target thresholds on a per unit basis as follows:

	Unitholders	General Partner
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First Target—$0.59 per unit up to $0.70 per unit	85%	15%
Second Target—$0.70 per unit up to $0.99 per unit	75%	25%
Over Second Target—Cash distributions greater than $0.99 per unit	50%	50%

During 2006, we paid cash and incentive distributions to our general partner for its general partner ownership interest of approximately $28.1 million and cash distributions of $14.5 million in connection with its ownership of the Class B common units. The cash distributions we make to our general partner for its general partner ownership interest exclude an amount equal to two percent of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

IN-KIND DISTRIBUTIONS

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B common units, we issue additional i-units to Enbridge Management in an amount determined by dividing the cash amount distributed per limited partner unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. In 2006, we distributed a total of 969,200 i-units to Enbridge Management and retained cash totaling approximately $44.6 million in connection with these in-kind distributions.

Holders of our Class C units receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distribution we pay to the holders of our Class A and Class B common units. We determine the additional Class C units we will issue by dividing the quarterly cash distribution per unit we pay on our Class A and Class B common units by the average market price of a Class A common unit as listed on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. In 2006, we distributed a total of 100,293 Class C units to our general partner in lieu of making cash distributions and retained cash totaling approximately $10.1 million in connection with these in-kind distributions.

OTHER RELATED PARTY TRANSACTIONS

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. We obtain managerial, administrative and operational services from our general partner and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

For further discussion of this and other related party transactions, refer to "Note 11—Related Party Transactions" in the Notes to the Consolidated Financial Statements beginning on Page F-2 of this Annual Report on Form 10-K.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or Enbridge Management, as appropriate. The board of directors then determines whether it is advisable to constitute a special committee of independent directors to evaluate the proposed transaction. If a special committee is appointed, the committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the special committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair to us and all of our unitholders.

Potential transactions with related persons that are not financially significant so as to require review by the board of directors are disclosed to the President of Enbridge Management and our general partner and reviewed for compliance with the Enbridge Statement on Business Conduct. The President may also consult with legal counsel in making such determination. If a related person transaction occurred and was later found not to comply with the Statement on Business Conduct, the transaction would be reported to the board of directors for further review and ratification or remedial action.

During 2006, the board of directors approved the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K) to be consummated in a future period:

- A like-kind exchange with Enbridge Energy Company, Inc. (not in its capacity as General Partner of the Partnership) of Line 13 on the Lakehead system for a new diluent return line to be constructed in the future as part of the Southern Lights project being constructed by Enbridge Energy Company, Inc.
- The purchase of a portion of the Spearhead pipeline system from an affiliate of Enbridge Energy Company, Inc. (not in its capacity as General Partner of the Partnership). The transaction will occur in the future and is valued at approximately $70 million.

During 2006, we entered into the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K):

- The purchase by Enbridge Energy Company, Inc. (not in its capacity as General Partner of the Partnership) of certain newly created Class C units as part of a private placement described in Notes 10 and 11 of our consolidated financial statements beginning at page F-1 of this Annual Report on Form 10-K for a total value of $250 million.
- An affiliate of Enbridge which provides employee services to the Partnership continued a previously existing employment relationship with Jan Connelly, the sister of Jeffrey A Connelly, a member of the Board of Directors. Ms. Connelly is employed in our Michigan office as the Manager, Origination. During 2006, she received total cash compensation of $135,573.72 and benefits estimated at approximately 35% of her cash compensation for a total of $183,024.52.

Item 14. Principal Accountant Fees and Services

The following table sets forth the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP, our principal independent auditors, for each of our last two fiscal years.

	For the years ended December 31, 2006	2005
Audit fees[1]	$2,405,200	$2,276,166
Audit related fees	—	—
Tax fees[2]	625,000	680,500
All other fees	—	—
Total	$3,030,200	$2,956,666

(1) Audit fees consist of fees billed for professional services rendered for the audit of our consolidated financial statements, reviews of our interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and our debt and equity offerings.

(2) Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1's.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance & Risk Committee of Enbridge Management's board of directors, or services up to $50,000 may be approved by the Chairman of the Audit, Finance & Risk Committee, under board of directors delegated authority. All services in 2006 and 2005 were approved by the Audit, Finance & Risk Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as a part of this report:

(1) *Financial Statements, which are incorporated by reference in Item 8 are included beginning on page F-1*.

a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

b. Consolidated Statements of Income for the years ended December 31, 2006, 2005, and 2004.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2006, 2005, and 2004.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005, and 2004.

e. Consolidated Statements of Financial Position as of December 31, 2006 and 2005.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2006, 2005, and 2004.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

All schedules have been omitted because they are not applicable, the required information is shown in the Consolidated Financial Statements or Notes thereto, or the required information is immaterial.

(3) *Exhibits.*

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 the General Partner

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

Date: February 22, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 22, 2007 by the following persons on behalf of the Registrant and in the capacities indicated.

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

/s/ M.A. MAKI
M.A. Maki
Vice President—Finance
(Principal Financial Officer)

/s/ T.L. MCGILL
T.L. McGill
President

/s/ J.R. BIRD
J.R. Bird
Director

/s/ J.A. CONNELLY
J.A. Connelly
Director

/s/ E.C. HAMBROOK
E.C. Hambrook
Director

/s/ M.O. HESSE
M.O. Hesse
Director

/s/ G.K. PETTY
G.K. Petty
Director

Index to Exhibits

Each exhibit identified below is filed as a part of this Annual report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 of 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 of 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 of the Partnership's 2000 Form 10-K/A dated October 9, 2001).
4.2	Registration Rights Agreement, dated August 15, 2006, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K dated August 16, 2006).
10.1	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (incorporated by reference to Exhibit 10.10 of the Partnership's 1991 Form 10-K).
10.2	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (incorporated by reference to Exhibit 10.11 of the Partnership's 1991 Form 10-K).
10.3	Contribution Agreement (incorporated by reference to Exhibit 10.1 of the Partnership's Registration Statement on Form S-3/A filed on July 8, 2002).
10.4	First Amendment to Contribution Agreement (incorporated by reference to Exhibit 10.8 of the Partnership's Registration Statement on Form S-3/A filed on September 24, 2002).
10.5	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on October 31, 2002).
10.6	Delegation of Control Agreement (incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.7	First Amending Agreement to the Delegation of Control Agreement dated as of February 21, 2005 (incorporated by reference to Exhibit 10.1 of the Partnership's Quarterly Report on Form 10-Q filed on May 5, 2005).
10.8	Amended and Restated Treasury Services Agreement (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.9	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.10	General and Administrative Services Agreement (incorporated by reference to Exhibit 10.5 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.11	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).

Exhibit Number	Description
10.12	Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference of Exhibit 10.11 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.13	First Amendment, dated January 12, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Quarterly Report on Form 10-Q filed on May 4, 2004).
10.14	Second Amendment, dated April 26, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q filed on May 4, 2004).
10.15	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 of the Partnership's Current Report on Form 8-K filed on April 19, 2005).
10.16	Fourth Amendment to the Amended and Restated Credit Agreement, dated January 24, 2003 (as amended by the First Amendment, dated January 12, 2004, the Second Amendment, dated April 26, 2004, and the Third Amendment dated April 14, 2005), 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 10.1 of the Partnership's Current Report on Form 8-K filed on September 21, 2005).
10.17	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.18	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.19	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.20	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.21	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.22	Amended and Restated 364-Day Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.12 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.23	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.13 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).

Exhibit Number	Description
10.24	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (incorporated by reference to Exhibit 10.14 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.25	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge (U.S.) Inc., as lender (incorporated by reference to Exhibit 10.15 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.26	Note Agreement and Mortgage, dated December 12, 1991 (incorporated by reference to Exhibit 10.1 of the Partnership's 1991 Form 10-K).
10.27	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (incorporated by reference to Exhibit 10.4 of the Partnership's 1992 Form 10-K).
10.28	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (incorporated by reference to Exhibit 10.17 of the Partnership's 1996 Form 10-K).
10.29	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project (incorporated by reference to Exhibit 10.21 of the Partnership's 1998 Form 10-K).
10.30	Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender (incorporated by reference to Exhibit 10.19 of the Partnership's 1998 Form 10-K).
10.31	Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (incorporated by reference to Exhibit 10.26 of the Partnership's 1999 Form 10-K).
10.32	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.1 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.33	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.34	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.35	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated November 16, 2000).
10.36	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.4 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.37[+]	Executive Employment Agreement, dated April 14, 2003, between Stephen J.J. Letwin, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed on May 3, 2006).

Exhibit Number	Description
10.38*+	Executive Employment Agreement, dated April 14, 2003, between J. Richard Bird, as Executive, and Enbridge Inc., as Corporation.
10.39+	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.40	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.41	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.42	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.43	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on January 9, 2004).
10.44	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.45	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.46	Sixth Supplemental Indenture dated December 21, 2006 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 21, 2006).
10.47	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on February 10, 2005).
10.48	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on November 17, 2005).
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Partnership's Annual Report on Form 10-K filed on March 12, 2004).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of PricewaterhouseCoopers LLP.
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.
99.1	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. (incorporated by reference to Exhibit 99.1 of the Partnership's Annual Report on Form 10-K filed February 25, 2005).

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, Texas 77002.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS, SUPPLEMENTARY INFORMATION AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

ENBRIDGE ENERGY PARTNERS, L.P.

FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this report have been omitted because they are not applicable or the required information is either immaterial or shown in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Partners of
Enbridge Energy Partners, L.P.:

We have completed integrated audits of Enbridge Energy Partners, L.P.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated statements of financial position and the related consolidated statements of income and comprehensive income, of partners capital and of cash flows present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Partnership maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2007

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

	Year ended December 31, 2006	2005	2004
	(in millions, except per unit amounts)		
Operating revenue	$6,509.0	$6,476.9	$4,291.7
Operating expenses			
Cost of natural gas (Note 15)	5,514.6	5,763.3	3,587.1
Operating and administrative	364.8	326.8	274.1
Power	107.6	74.8	72.8
Depreciation and amortization (Note 6)	135.1	138.2	120.5
Gain on sale of assets	—	(18.1)	—
	6,122.1	6,285.0	4,054.5
Operating income	386.9	191.9	237.2
Interest expense	(110.5)	(107.7)	(88.4)
Rate refunds (Note 13)	—	—	(13.6)
Other income	8.5	5.0	3.0
Net income	$ 284.9	$ 89.2	$ 138.2
Net income allocable to limited partner units	$ 254.0	$ 65.7	$ 115.7
Net income per limited partner unit (basic and diluted) (Note 4)	$ 3.62	$ 1.06	$ 2.06
Weighted average limited partner units outstanding	70.2	62.1	56.1
Cash distributions paid per limited partner unit	$ 3.70	$ 3.70	$ 3.70

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year ended December 31, 2006	2005	2004
		(in millions)	
Net income	$284.9	$ 89.2	$138.2
Other comprehensive income (loss) (Notes 14 and 15)	112.5	(181.3)	(56.8)
Comprehensive income (loss)	$397.4	$ (92.1)	$ 81.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2006	2005	2004
		(in millions)	
Cash provided by operating activities			
Net income	$ 284.9	$ 89.2	$ 138.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 6)	135.1	138.2	120.5
Derivative fair value (gains) losses (Notes 14 and 15)	(64.4)	58.4	3.2
Environmental liabilities (Note 12)	(1.4)	(0.5)	(2.0)
Gain on sale of assets (Note 3)	—	(18.1)	—
Inventory market price adjustments (Note 5)	17.7	—	—
Other	9.7	(0.3)	0.4
Changes in operating assets and liabilities, net of cash acquired:			
Receivables, trade and other	(37.0)	(38.0)	(25.4)
Due from General Partner and affiliates	(10.4)	(12.4)	(0.5)
Accrued receivables	98.8	(237.1)	(128.5)
Inventory	1.1	(57.5)	(60.8)
Current and long-term other assets (Notes 14 and 15)	(2.7)	(2.2)	15.3
Due to General Partner and affiliates (Note 11)	10.1	2.6	8.1
Accounts payable and other (Notes 2, 14 and 15)	4.3	42.2	36.8
Accrued purchases	(116.4)	295.3	120.8
Interest payable	4.4	8.8	14.5
Property and other taxes payable	(2.0)	(1.5)	4.8
Settlement of interest rate derivatives (Note 15)	(10.2)	—	—
Net cash provided by operating activities	321.6	267.1	245.4
Cash used in investing activities			
Additions to property, plant and equipment	(864.4)	(344.8)	(288.8)
Changes in construction payables	30.4	2.8	10.0
Asset acquisitions, net of cash acquired (Note 3)	(33.3)	(186.4)	(141.0)
Proceeds from sale of assets (Note 3)	0.2	105.4	—
Settlement of natural gas collars (Note 3 and 15)	—	(16.3)	—
Other	0.1	2.2	0.7
Net cash used in investing activities	(867.0)	(437.1)	(419.1)
Cash provided by financing activities			
Proceeds from unit issuances, net (Note 10)	509.6	268.6	194.2
Distributions to partners (Note 10)	(227.4)	(210.6)	(191.0)
Repayments of Credit Facilities, net (Note 9)	—	(175.0)	(280.0)
Net issuances of commercial paper (Note 9)	111.4	330.0	—
Proceeds from issuance of senior notes, net of issue costs (Note 9)	297.6	—	495.4
Repayments on affiliate loan (Note 11)	(20.0)	—	—
Repayments of First Mortgage Notes (Note 9)	(31.0)	(31.0)	(31.0)
Other	—	(0.5)	—
Net cash provided by financing activities	640.2	181.5	187.6
Net increase in cash and cash equivalents	94.8	11.5	13.9
Cash and cash equivalents at beginning of year	89.8	78.3	64.4
Cash and cash equivalents at end of year	$ 184.6	$ 89.8	$ 78.3

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2006	December 31, 2005
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 2)	$ 184.6	$ 89.8
Receivables, trade and other, net of allowance for doubtful accounts of $2.4 in 2006 and $4.5 in 2005	146.7	109.7
Due from General Partner and affiliates	30.5	20.1
Accrued receivables	516.5	615.3
Inventory (Note 5)	117.1	138.9
Other current assets (Notes 14 and 15)	13.9	11.5
	1,009.3	985.3
Property, plant and equipment, net (Note 6)	3,824.9	3,080.0
Other assets, net (Notes 14 and 15)	32.5	22.2
Goodwill (Note 7)	265.7	258.2
Intangibles, net (Note 8)	91.4	82.7
	$5,223.8	$4,428.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 11)	$ 22.6	$ 12.5
Accounts payable and other (Notes 14 and 15)	211.5	247.9
Accrued purchases	530.3	646.7
Interest payable	11.4	11.4
Property and other taxes payable	18.6	21.8
Loans from General Partner and affiliates (Note 11)	136.2	—
Current maturities of long-term debt (Note 9)	31.0	31.0
	961.6	971.3
Long-term debt (Note 9)	2,066.1	1,682.9
Environmental liabilities (Note 12)	3.3	4.8
Loans from General Partner and affiliates (Note 11)	—	151.8
Other long-term liabilities (Notes 14 and 15)	149.4	253.8
	3,180.4	3,064.6
Commitments and contingencies (Note 13)		
Partners' capital (Note 10)		
Class A common units (Units issued—49,938,834 in 2006 and 2005)	1,141.7	1,142.4
Class B common units (Units issued—3,912,750 in 2006 and 2005)	67.6	67.2
Class C units (Units issued—11,070,152 in 2006)	509.8	—
i-units (Units issued—12,674,148 in 2006 and 11,704,948 in 2005)	466.3	421.7
General Partner	47.6	34.6
Accumulated other comprehensive loss (Notes 14 and 15)	(189.6)	(302.1)
	2,043.4	1,363.8
	$5,223.8	$4,428.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Year ended December 31,					
	2006		2005		2004	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Class A common units:						
Beginning balance	49,938,834	$1,142.4	44,296,134	$1,021.6	40,166,134	$ 914.9
Net income allocation	—	184.1	—	48.9	—	85.4
Allocation of proceeds and issuance costs from unit issuance	—	—	5,642,700	242.7	4,130,000	175.0
Distributions	—	(184.8)	—	(170.8)	—	(153.7)
Ending balance	49,938,834	1,141.7	49,938,834	1,142.4	44,296,134	1,021.6
Class B common units:						
Beginning balance	3,912,750	67.2	3,912,750	66.7	3,912,750	64.2
Net income allocation	—	14.9	—	4.8	—	8.7
Allocation of proceeds and issuance costs from unit issuance	—	—	—	10.2	—	8.2
Distributions	—	(14.5)	—	(14.5)	—	(14.4)
Ending balance	3,912,750	67.6	3,912,750	67.2	3,912,750	66.7
Class C units:						
Beginning balance	—	—	—	—	—	—
Net income allocation	—	10.4	—	—	—	—
Allocation of proceeds and issuance costs from unit issuance	10,869,565	499.4	—	—	—	—
Distributions	200,587	—	—	—	—	—
Ending balance	11,070,152	509.8	—	—	—	—
i-units:						
Beginning balance	11,704,948	421.7	10,902,409	399.4	10,062,170	370.7
Net income allocation	—	44.6	—	12.0	—	21.6
Allocation of proceeds and issuance costs from unit issuance	—	—	—	10.3	—	7.1
Distributions	969,200	—	802,539	—	840,239	—
Ending balance	12,674,148	466.3	11,704,948	421.7	10,902,409	399.4
General Partner:						
Beginning balance		34.6		31.0		27.5
Net income allocation		30.9		23.5		22.5
Allocation of proceeds and issuance costs from unit issuance		—		(0.3)		(0.2)
General Partner contribution		10.2		5.7		4.1
Distributions		(28.1)		(25.3)		(22.9)
Ending balance		47.6		34.6		31.0
Accumulated other comprehensive loss:						
Beginning balance		(302.1)		(120.8)		(64.0)
Unrealized gain (loss) on derivative financial instruments		112.5		(181.3)		(56.8)
Ending balance		(189.6)		(302.1)		(120.8)
Partners' capital at December 31,		$2,043.4		$1,363.8		$1,397.9

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

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

General

Enbridge Energy Partners, L.P. and its consolidated subsidiaries, referred to herein as "we," "us," "our," and the "Partnership," is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transmission and marketing assets in the United States of America. Our Class A common units are traded on the New York Stock Exchange ("NYSE") under the symbol "EEP."

We were formed in 1991 by Enbridge Energy Company, Inc. (the "General Partner"), which is an indirect, wholly-owned subsidiary of Enbridge Inc. ("Enbridge") of Calgary, Alberta. We were formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership (the "Lakehead Partnership") which owns the United States portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada.

We are a geographically and operationally diversified organization, providing crude oil gathering, transportation and storage services, and natural gas gathering, treating, processing, marketing and transportation services in the Gulf Coast and Mid-continent regions of the United States. We hold our assets in a series of limited liability companies and limited partnerships that we own directly or indirectly.

Our ownership includes general partner interests and limited partner interests. Our limited partner interests consist of Class A and Class B common units, Class C units and i-units, which we collectively refer to as the limited partner units. At December 31, 2006 and 2005, our ownership is distributed as follows:

	2006	2005
Class A common units owned by the public	63.1%	74.7%
Class B common units owned by our General Partner	4.9%	5.8%
Class C units owned by our General Partner	7.0%	—
Class C units owned by an institutional investor	7.0%	—
i-units owned by Enbridge Management	16.0%	17.5%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C. and its subsidiary, which we refer to as Enbridge Management, is a Delaware limited liability company, formed in May 2002. Our General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management's Listed Shares are traded on the NYSE under the symbol "EEQ." Enbridge Management owns all of a special class of our limited partner interests, referred to as "i-units" and receives its earnings from this investment.

Enbridge Management's principal activity is managing and controlling our business and affairs pursuant to a delegation of control agreement with our general partner. The delegation of control agreement provides that Enbridge Management will not amend or propose to amend our partnership agreement, allow a merger or consolidation involving us, allow a sale or exchange of all or substantially all of our assets or dissolve or liquidate us without the approval of our general partner. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being our limited partner and managing our business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of our general partner and is publicly traded on the NYSE and Toronto Stock Exchange under the symbol "ENB." Enbridge is a leader in the transportation and distribution of energy, with a focus on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution in North America. Enbridge also has international interests located in Western Europe and Latin America. At December 31, 2006 and 2005, Enbridge and its consolidated subsidiaries owned an effective 16.7% and 10.8% interest in us through its ownership in Enbridge Management and our general partner.

Business Segments

We conduct our business through three segments: Liquids, Natural Gas, and Marketing.

Liquids

Our Liquids segment includes the Lakehead, North Dakota, and the Mid-Continent systems. Our Lakehead system consists of an interstate common carrier crude oil and liquid petroleum pipeline that is regulated by the Federal Energy Regulatory Commission, or FERC, and storage assets, all of which are located in the Great Lakes and Midwest regions of the United States. Our Lakehead system, together with the Enbridge system in Canada owned by Enbridge, forms the longest liquid petroleum pipeline in the world. The Lakehead system, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Our North Dakota system includes approximately 330 miles of crude oil gathering lines connected to an interstate transportation line that is approximately 620 miles long and is regulated by the FERC. The North Dakota system connects directly into the Lakehead system in the state of Minnesota. Our Mid-Continent system consists of over 480 miles of active crude oil pipelines including the FERC-regulated Ozark pipeline and approximately 12.8 million barrels of storage capacity, which serves refineries in the U.S. Mid-continent region from Cushing, Oklahoma.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, treating and processing plants and related facilities predominantly located in active producing basins in east and north Texas, as well as the Texas panhandle and western Oklahoma. Our Natural Gas segment includes nine natural gas treating plants and 17 natural gas processing plants at December 31, 2006, excluding plants that are inactive or under construction. In addition, our Natural Gas segment includes approximately 11,000 miles of natural gas gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting natural gas liquids ("NGL" or "NGLs"), crude oil and carbon dioxide.

Our Natural Gas segment also includes four FERC-regulated natural gas transmission pipeline systems located in the Mid-continent and Gulf Coast regions of the United States.

Marketing

Our Marketing segment primarily provides natural gas supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines as well as other interconnected natural gas pipeline systems. We primarily undertake marketing activities to increase the utilization of our natural gas pipelines, realize incremental margin on gas purchased at the wellhead, and provide value-added services to customers.

Our Marketing business purchases third-party pipeline transportation capacity which provides us and our customers with access to natural gas markets that might not be directly accessible from our existing natural gas pipelines. Our Marketing business also purchases third-party storage capacity which permits us to inject and store natural gas over various periods of time for withdrawal as these products become needed by end users of natural gas. These contracts may be denoted as firm transportation, interruptible transportation, firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with our natural gas purchase and sale contracts and to provide us with opportunities to competitively market the natural gas and NGL products.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. We regularly evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the circumstances. Nevertheless, actual results may differ significantly from these estimates. We record the effect of any revisions to these estimates in our consolidated financial statements in the period in which the facts that give rise to the revision become known.

Principles of Consolidation

The consolidated financial statements include the accounts of the Partnership and its wholly-owned subsidiaries on a consolidated basis. All significant intercompany accounts and transactions have been eliminated in consolidation.

Accounting for Regulated Operations

Certain of our liquids and natural gas activities are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers.

Certain of our natural gas systems are subject to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, we record certain assets and liabilities that result from the regulated ratemaking process that would not be recorded for non-regulated entities under U.S. GAAP.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas

Liquids

Revenues of our Liquids segment are primarily derived from two sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC and contract storage revenues related to our crude oil storage assets. The tariffs established for our interstate pipelines specify the amounts to be paid by shippers for service between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. We recognize revenue upon delivery of products to our customers, when pricing is determinable and collectibility is reasonably assured. We recognize contract storage revenues based on contractual terms under which customers pay for the option to use available storage capacity and/or a fee based on through-put volumes. We recognize revenues as storage services are rendered, pricing is determinable and collectibility is reasonably assured. In the Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk.

Natural Gas

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectibility is reasonably assured. We derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based Arrangements:

Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services provided and do not depend directly on commodity prices. Revenues of the Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services. Customers of the FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes.

Other Arrangements:

We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. We will continue to hedge a significant amount of our commodity price risk to support the stability of our cash flows. Refer to Note 15 for more information about the derivative activities we use to mitigate this commodity price risk.

These other types of arrangements are categorized as follows:

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.
- Percentage-of-Proceeds Contracts—Under the terms of these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we then sell at market prices and retain as our fee.
- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs and condensate extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGL and condensate.
- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw gas at the wellhead, we also sell for our own account at market prices, the resulting residue gas. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with an energy content equivalent to the original raw gas we received as measured in British thermal units, or Btu.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. In order to protect our unitholders from volatility in our cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to effectively fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time.

Marketing

Revenues of our Marketing segment are derived from providing supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Natural gas marketing activities are primarily undertaken to realize incremental revenues on natural gas purchased at the wellhead, and to provide other services valued by our customers. In general, natural gas purchased and sold by our Marketing business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated revenues result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At the request of some customers, we will enter into long-term fixed price purchase or sales contracts with our customers and usually will enter into offsetting positions under the same or similar terms. We recognize revenues upon delivery of natural gas and NGLs to our customers, when services are rendered, pricing is determinable and collectibility is reasonably assured.

Estimation of Revenue and Cost of Natural Gas

For our natural gas and marketing businesses, we must estimate our current month revenue and cost of gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each of the years ended December 31, 2006, 2005 and 2004. We believe that the assumptions underlying these estimates will not be significantly different from actual amounts due to the routine nature of these estimates and the stability of our processes.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

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. As such, included in Accounts payable and other on our Consolidated Statements of Financial Position are obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $46.9 million and $46.5 million at December 31, 2006 and 2005, respectively.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

Inventory

Inventory includes product inventory and materials and supplies inventory. We record all product inventories at the lower of our cost as determined on a weighted average basis, or market. The product inventory consists of liquids and natural gas. Upon disposition, product inventory is recorded to Cost of natural gas at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

Materials and supplies inventory is either used during operations and charged to operating expense as incurred, or used for capital projects and new construction, and capitalized to property, plant and equipment.

Oil Measurement Gains and Losses

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

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

Difficulties are inherent in quantifying oil measurement gains and losses because physical measurements of volumes are not practical, as products continuously move through our pipelines and virtually all of these pipelines are located underground. Quantifying oil measurement gains and losses is especially difficult for us because of the length of the pipeline systems and the number of different grades of crude oil and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement gains and losses. Material changes in our assumptions may result in revisions to our oil measurement gain and loss estimates in the period determined.

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in kind through the receipt or delivery of natural gas in the future. Gas imbalances are recorded as Accrued receivables and Accrued purchases on our Consolidated Statements of Financial Position using the posted index prices, which approximate market rates, or our weighted average cost of gas.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* or SFAS No. 71, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. 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. Examples of enhancement expenditures include costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving a major segment of a pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion.

Regulatory guidance issued by the FERC requires us to expense certain costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under this guidance, beginning in January 2006, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We adopted this guidance prospectively in January 2006 for all our pipeline systems. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition continue to be capitalized. We have historically capitalized initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects. Beginning January 2006, costs of this nature are expensed as incurred, which is consistent with industry practice and the regulatory guidance issued by the FERC. However, we continue to capitalize initial construction hydrostatic testing cost and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also capitalized are certain costs such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred. Our adoption of the regulatory guidance did not significantly affect our financial position, results of operations or cash flows.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of their estimated useful lives or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we will recognize a gain or loss in our Consolidated Statements of Income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these regular assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Income.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is allocated to two of our segments, Natural Gas and Marketing.

Goodwill is not amortized, but is tested for impairment annually based on carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time we determine that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, we make estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with our most recent five-year plan, which we use to manage the business. We have not identified or recognized any goodwill impairments during the years ended December 31, 2006, 2005 or 2004.

Intangibles, Net

Intangibles, net, consist of customer contracts for the purchase and sale of natural gas and natural gas supply opportunities. We amortize these assets on a straight-line basis over the weighted average useful life of the underlying assets, representing the period over which the asset is expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. We did not identify nor recognize any impairment of our intangible assets for the years ended December 31, 2006, 2005, or 2004.

Other Assets

Other assets primarily include deferred financing costs, which we amortize on a straight-line basis, which approximates the effective interest method, over the life of the related debt to interest expense on our Consolidated Statements of Income.

Income Taxes

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose income tax. These taxes on our net income are borne by our unitholders through the allocation of taxable income. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by imposing a new tax based upon modified gross revenue. Under the provisions of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes,* we have determined that this tax is an income tax. As a result, we have recognized deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. Our initial accounting for the enactment of this income tax did not materially affect our results of operation, financial condition or cash flows.

Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in us is not available.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates and commodity prices of natural gas, NGL, condensate and fraction margins (the relative price differential between NGL sales and the offsetting natural gas purchases). In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), we record all derivative financial instruments on our Consolidated Statements of Financial Position at fair market value. We record the fair market value of our derivative financial instruments in the Consolidated Statements of Financial Position as current and long-term assets or liabilities on a net basis by counterparty. For those instruments that qualify for hedge accounting, the accounting treatment depends on the intended use and designation of each instrument. For our derivative financial instruments related to commodities that do not qualify for hedge accounting, the change in market value is recorded as a component of Cost of natural gas in the Consolidated Statements of Income. For our derivative financial instruments related to interest rates that do not qualify for hedge accounting, the change in fair market value is recorded as a component of Interest expense in the Consolidated Statements of Income.

In implementing our hedging programs, we have established a formal analysis, execution and reporting framework that requires the approval of the board of directors of Enbridge Management or a committee of our senior management. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment that we use can generally be divided into two categories: 1) cash flow hedges, or 2) fair value hedges. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions. We enter into fair value hedges to reduce the risk of changes in the value of recognized assets or liabilities.

Price assumptions we use to value the cash flow and fair value hedges can affect net income for each period. We use published market price information where available, or quotations from over-the-counter ("OTC") market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or the fair value of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

For cash flow hedges, changes in the fair market values of derivative financial instruments, to the extent that the hedges are determined to be highly effective, are recorded as a component of Accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in fair market value is recognized immediately in earnings. For fair value hedges, the change in fair market value of the financial instrument is determined each period and is taken into earnings. In addition, the change in the fair market value of the hedged item is also calculated and taken into earnings. To the extent that the two valuations offset, the hedge is effective and net earnings is not affected.

Our earnings are also affected by use of the mark-to-market method of accounting as required under GAAP for derivative financial instruments that do not qualify for hedge accounting. We use short-term, highly liquid derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within our Marketing segment. However, these derivative financial instruments, do not qualify for hedge accounting treatment under SFAS No. 133, and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying indices, primarily commodity prices. The fair market value of these derivative financial instruments is determined using price data from highly liquid markets such as the New York Mercantile Exchange, or NYMEX, OTC market makers, or other similar sources.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. Amounts for remediation of existing environmental contamination caused by past operations, which do not benefit future periods by preventing or eliminating future contamination, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. These estimates are subject to revision in future periods based on actual costs or new information and are included on the balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss. We typically expense legal costs associated with loss contingencies as such costs are incurred.

Asset Retirement Obligations

We record a liability for the fair value of asset retirement obligations, or ARO, on a discounted basis, in the period in which the liability is incurred. Typically we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for AROs when assets are taken out of service or otherwise abandoned.

In December 2005, we adopted the provisions of Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47"). FIN 47 requires us to recognize a liability and related asset, consistent with SFAS No. 143, for the fair value of conditional asset retirement obligations that we can reasonably estimate. FIN 47 also provides specific guidance regarding when an asset retirement obligation is reasonably estimable including when sufficient information is available to apply an expected present value technique. As indicated in the table below, our implementation of FIN 47 did not have a material effect on our consolidated financial statements.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate an abandonment retirement obligation cost. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's intent, or the asset's estimated economic life. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

We did not record any additional AROs for the year ended December 31, 2006, and recorded an asset and liability of $2.1 million for AROs for the year ended December 31, 2005. We recorded accretion expense of $0.2 million, $0.5 million and $0.1 million, respectively, in the Consolidated Statements of Income for the years ended December 31, 2006, 2005 and 2004 for previously recorded asset retirement obligation liabilities.

No assets are legally restricted for purposes of settling our ARO for each of the years ended December 31, 2006 and 2005. Following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for each of the years ended December 31, 2006 and 2005:

	2006	2005
	(in millions)	
Balance at beginning of period	$3.6	$1.0
Implementation of FIN 47—Liability	—	2.1
Accretion expense	0.2	0.5
Balance at end of period	$3.8	$3.6

Comparative Amounts

We have made reclassifications to the prior years' reported amounts to conform to our presentation in the 2006 consolidated financial statements. These reclassifications were made within the Consolidated Statements of Cash Flows within net cash provided by operating activities and have no effect on net income.

Recent Accounting Pronouncements Not Yet Adopted

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157, *Fair Value Measurements.* This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurement. The statement is effective for fiscal years beginning after November 15, 2007, and with limited exceptions is to be applied prospectively as of the beginning of the fiscal year initially adopted. We expect to adopt the provisions of this statement prospectively beginning January 1, 2008. We do not expect our adoption of this pronouncement to materially affect our consolidated financial statements. However, our adoption of this pronouncement may affect our disclosures regarding derivative financial instruments and indebtedness.

Accounting for Registration Payment Arrangements

In December 2006, the FASB issued FASB Staff Position FSP EITF 00-19-2, *Accounting for Registration Payment Arrangements*. This FASB Staff Position, or FSP, specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with FASB Statement No. 5, *Accounting for Contingencies*. This FSP also requires certain disclosures regarding registration payment arrangements and liabilities recorded for such purposes. This FSP is immediately effective for registration payment arrangements entered into or modified after December 21, 2006. The guidance of this FSP is effective for fiscal years beginning after December 15, 2006, and interim periods within those fiscal years for registration payment arrangements entered into prior to December 21, 2006. This FSP requires adoption by reporting a change in accounting principle through a cumulative-effect adjustment to the opening balance of our partners' capital accounts as of the first interim period of the year in which this FSP is initially applied. We do not expect our adoption of this FSP to materially affect our financial position, results of operations or cash flows.

Staff Accounting Bulletin No. 108

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108. This Bulletin requires a "dual approach" for quantifications of errors using both a method that focuses on the income statement impact, including the cumulative effect of prior years' misstatements, and a method that focuses on the period-end balance sheet. We adopted SAB No. 108 as of December 31, 2006. The adoption of this Bulletin did not have a material impact on our consolidated financial statements.

3. ACQUISITIONS AND DISPOSITIONS

We accounted for each of our completed acquisitions using the purchase method and recorded the assets acquired and liabilities assumed at their estimated fair market values as of the date of purchase. We have included the results of operations from each of these acquisitions in our earnings from the acquisition date.

2006 Acquisitions and Dispositions

Oakhill Acquisition

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

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

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

2005 Acquisitions and Dispositions

North Texas Natural Gas System

In January 2005, we acquired natural gas gathering and processing assets in north Texas for $164.6 million in cash, including transaction costs of $0.5 million. The assets we acquired serve the Fort Worth Basin, which is mature, but experiencing minimal production decline rates and include:

- 2,200 miles of gas gathering pipelines; and
- four processing plants with aggregate processing capacity of 121 MMcf/d of natural gas.

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

We allocated the purchase price of the assets acquired and liabilities assumed 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

Other 2005 Acquisitions

In June 2005, we acquired for $20.1 million in cash, a natural gas pipeline and related facilities consisting of 92 miles of 20-inch diameter pipeline that extends from Pampa, Texas into western Oklahoma and has interconnects with our Anadarko system. We integrated this pipeline into our existing Anadarko system and have included the assets and operating results in our Natural Gas segment from the date of acquisition. The purchase price for this acquisition was allocated to property, plant and equipment for $19.1 million and goodwill for $1.0 million. We also acquired other gathering and processing assets during 2005 that are complementary to our existing natural gas systems for cash totaling approximately $1.7 million.

Sale of Gathering and Processing Assets

In December 2005, we sold for $105.4 million in cash, a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems with a carrying value of approximately $86.9 million. We incurred selling costs of approximately $0.4 million and recognized a gain on the sale of approximately $18.1 million. The facilities we sold represent non-strategic assets within our Natural Gas segment. In connection with this sale, we paid approximately $16.3 million to settle natural gas collars on 2,000 Million British Thermal units per day, or MMBtu/d, associated with the natural gas produced by these assets and entered into offsetting derivatives at market to close out derivatives previously classified as hedges of 273 Barrels per day, or Bpd, of NGL produced by these assets. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Refer to Note 15 for additional discussion regarding our derivative activities.

2004 Acquisitions

Mid-Continent System

In March 2004, we acquired crude oil pipeline and storage assets, which we refer to as the Mid-Continent system, for $117.0 million, including transaction costs of $2.0 million. The assets acquired serve refineries in the U.S. Mid-Continent from Cushing, Oklahoma and include:

- The 433-mile Ozark pipeline from Cushing to Wood River, Illinois;
- A 1.2 million barrel storage terminal located in El Dorado, Kansas;
- The 47-mile West Tulsa pipeline in Oklahoma; and
- A storage terminal at Cushing, with 8.3 million barrels of storage capacity.

These systems were acquired to provide cash flows primarily from toll or fee-based revenues from a combination of regulated assets and contracted unregulated assets. We included the assets and results of operations in our Liquids segment from the acquisition date. The value allocated to the assets was determined by an independent appraisal.

We allocated the purchase price to assets acquired and liabilities assumed as follows (in millions):

Purchase Price:	
Cash paid, including transaction costs	$117.0
Allocation of purchase price:	
Property, plant and equipment	$117.5
Current assets	0.2
Current liabilities	(0.2)
Environmental liabilities	(0.5)
Total	$117.0

Other 2004 Acquisitions

During 2004, we completed five separate acquisitions of natural gas assets for a total of $10.9 million. The purchase price for these acquisitions was applied to property, plant, and equipment with no associated goodwill recorded. We included the results of operations for the acquisitions in our Natural Gas segment from the acquisition date.

In March 2004, we also purchased natural gas transmission and gathering pipeline assets for $13.1 million. The assets, referred to as the "Palo Duro" system, are located in Texas between our existing Anadarko and North Texas systems, and have increased our natural gas delivery flexibility to our customers. The assets purchased include approximately 400 miles of natural gas transmission and gathering pipelines, together with 5,200 horsepower of compression. We allocated the purchase price for this acquisition to property, plant and equipment and no goodwill was recorded. The Palo Duro system's results of operations are included in our Natural Gas segment from the date of acquisition.

4. NET INCOME PER LIMITED PARTNER UNIT

We compute net income per limited partner unit by dividing net income, after deducting our allocation to the General Partner, 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, therefore basic and diluted earnings per unit amounts are equal. Net income per limited partner unit was determined as follows:

	Year ended December 31,		
	2006	2005	2004
	(in millions, except per unit amounts)		
Net income	$284.9	$ 89.2	$138.2
Allocations to the General Partner:			
Net income allocated to General Partner	(5.7)	(1.8)	(2.8)
Incentive distributions to General Partner	(25.1)	(21.6)	(19.6)
Historical cost depreciation adjustments	(0.1)	(0.1)	(0.1)
	(30.9)	(23.5)	(22.5)
Net income allocable to limited partner units	$254.0	$ 65.7	$115.7
Weighted average units outstanding	70.2	62.1	56.1
Net income per limited partner unit (basic and diluted)	$ 3.62	$ 1.06	$ 2.06

5. INVENTORY

Inventory is comprised of the following:

	December 31, 2006	December 31, 2005
	(in millions)	
Material and supplies	$ 3.8	$ 8.3
Liquids inventory	9.9	11.1
Natural gas and natural gas liquids inventory	103.4	119.5
	$117.1	$138.9

Our inventory at December 31, 2006 is net of charges totaling $17.7 million we recorded in 2006 to reduce the cost basis of our natural gas inventory to reflect market value. The lower of cost or market adjustments are included in the Cost of natural gas of our Natural Gas and Marketing segments on our Consolidated Statements of Income.

6. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	Depreciation Rates	December 31, 2006	December 31, 2005
		(in millions)	
Land	—	$ 14.3	$ 13.8
Rights-of-way	1.5% - 6.4%	298.6	280.2
Pipeline	0.6% - 12.0%	2,320.8	2,194.2
Pumping equipment, buildings and tanks	1.5% - 14.3%	747.4	673.0
Compressors, meters, and other operating equipment	0.6% - 20.0%	418.1	310.0
Vehicles, office furniture and equipment	0.6% - 33.3%	112.4	102.7
Processing and treating plants	2.7% - 4.0%	86.4	79.0
Construction in progress	—	733.6	209.1
Total property, plant and equipment		4,731.6	3,862.0
Accumulated depreciation		(906.7)	(782.0)
Net property, plant and equipment		$3,824.9	$3,080.0

We have assets included in the above table that are highly depreciated, which yield depreciation rates that suggest these assets have significant remaining useful lives.

Based on third-party studies commissioned by management, we implemented revised depreciation rates for the Lakehead system effective January 1, 2006, and the Anadarko, North Texas and East Texas systems effective August 1, 2005. We reduced the annual composite rate, representing the expected remaining service lives of the system assets, from 3.20% to 2.63% for our Lakehead system and from 4.0% to 3.4% for our Anadarko, North Texas and East Texas systems. As a result, our depreciation expense for the years ended December 31, 2006 and 2005, respectively, was approximately $14.5 million and $2.5 million lower than if these rates had not been reduced. Additionally, effective July 1, 2006, we increased the annual composite rates on three of our FERC-regulated pipelines, representing reductions to the expected remaining service lives of our AlaTenn, KPC and Midla systems. These increases resulted in approximately $1.3 million of additional depreciation in 2006.