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								Carrying Amount	Fair Value
		2007	2008	2009	2010	2011	Thereafter	Total	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		Notional Amount	Fair Value	
								Asset	Liability		Asset	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.