UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended DECEMBER 31, 2006

OR

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

For the transition period from to

Commission File Number: 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of Registrant as specified in its charter)

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Units	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-Accelerated Filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Registrant's Class A Common Units held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2006, was $2,174,836,221.

As of February 22, 2007 the Registrant has 49,938,834 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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This Annual Report on Form 10-K contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "should," or "will" or the negative of those terms or other variations of them or comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included elsewhere in this Form 10-K.

Glossary

The following abbreviations, acronyms, or terms used in this Form 10-K are defined below:

AEUB	Alberta Energy and Utilities Board
Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle, which were acquired on October 17, 2002
AOCI	Accumulated other comprehensive income
AOSP	Athabasca Oil Sands Project, located in northern Alberta, Canada
Bbl.	Barrel of liquids (approximately 42 U.S. gallons)
BlackRock	BlackRock Ventures Inc., an unrelated producer of heavy oil in Western Canada
Bpd	Barrels per day
CAA	Clean Air Act
Canadian Natural	Canadian Natural Resources Limited, an unrelated energy company
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of our Lakehead system's customers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CAD	Amount denominated in Canadian dollars
CWA	Clean Water Act
DOT	Department of Transportation
East Texas system	Natural gas gathering, treating and processing assets in East Texas acquired on November 30, 2001. Also includes a system formerly known as the Northeast Texas system acquired October 17, 2002.
Enbridge	Enbridge Inc., of Calgary, Alberta, Canada, the ultimate parent of the General Partner
Enbridge Management	Enbridge Energy Management, L.L.C.
Enbridge system	Canadian portion of the System
Enbridge Pipelines	Enbridge Pipelines Inc.
EnCana	EnCana Corporation, an unrelated producer of natural gas and crude oil
EP Act	Energy Policy Act of 1992
EPACT	Energy Policy Act of 2005
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
General Partner	Enbridge Energy Company, Inc., general partner of the Partnership
HCA	High consequence area
ICA	Interstate Commerce Act
KPC	Kansas Pipeline system, acquired on October 17, 2002
Lakehead Partnership	Enbridge Energy, Limited Partnership, a subsidiary of the Partnership
Lakehead system	U.S. portion of the System
LIBOR	London Interbank Offered Rate—British Bankers Association's average settlement rate for deposits in U.S. dollars
$M^{(3)}$	Cubic meters of liquid = 6.289811661 Bbl
MLP	Master Limited Partnership
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day

Midcoast system	Natural gas gathering, treating, processing, transmission and marketing assets acquired October 17, 2002
Mid-Continent system	Crude oil pipelines and storage facilities located in the mid-continent of the U.S. and acquired on March 1, 2004
NEB	National Energy Board, a Canadian federal agency that regulates Canada's energy industry
NGA	Natural Gas Act
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act
NOPR	Notice of Proposed Rulemaking issued by the FERC.
North Dakota system	Liquids petroleum pipeline system in the Upper Midwest United States acquired on May 18, 2001
Northeast Texas system	Natural gas gathering and processing assets acquired on October 17, 2002 and integrated with the East Texas system
North Texas system	Natural gas gathering and processing assets acquired on December 31, 2003
NYMEX	The New York Mercantile Exchange where natural gas futures, options contracts, and other energy futures are traded
NYSE	New York Stock Exchange
OCSLA	Outer Continental Shelf Lands Act
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety
PADD	Petroleum Administration for Defense Districts
PADD I	Consists of Connecticut, Delaware, District of Columbia, Florida, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia and West Virginia
PADD II	Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin
PADD III	Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas
PADD IV	Consists of Idaho, Montana, Wyoming and Colorado
PADD V	Consists of Washington, Oregon, California, Arizona, Alaska, Hawaii and Nevada
Palo Duro system	Natural gas transmission and gathering pipeline assets located in Texas between the Anadarko system and the North Texas system acquired on March 1, 2004 and integrated with the Anadarko system during 2005
Partnership Agreement	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership
Partnership	Enbridge Energy Partners, L.P. and its consolidated subsidiaries
PHMSA	Pipeline and Hazardous Materials Safety Administration (formerly OPS)
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
PPIFG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act
PSI Act	Pipeline Safety Improvement Act
RCRA	Resource Conservation & Recovery Act
SAGD	Steam assisted gravity drainage
SEC	Securities and Exchange Commission

SEP II.	System Expansion Program II, an expansion program on the Lakehead system
Settlement Agreement.	A FERC approved settlement agreement, signed October 1996
SFAS	Statement of Financial Accounting Standards
SFPP.	Sante Fe Pacific Pipelines, L.P., an unrelated pipeline company
Suncor	Suncor Energy Inc., an unrelated energy company
Syncrude	Syncrude Canada Ltd., an unrelated energy company
Synthetic crude oil	Product that results from upgrading or blending bitumen into a crude oil stream which can be readily refined by most conventional refineries
System	The combined liquid petroleum pipeline operations of the Lakehead system and the Enbridge system
Tariff Agreement	A 1998 offer of settlement filed with the FERC
Terrace.	Terrace Expansion Program, an expansion program on the Lakehead system
WCSB.	Western Canadian Sedimentary Basin

PART I

Item 1.—Business

OVERVIEW

In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We are a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States of America. Our Class A common units are traded on the NYSE under the symbol "EEP."

We were formed in 1991 by our general partner to own and operate the Lakehead system, which is the U.S. portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada. A subsidiary of Enbridge owns the Canadian portion of the System. Enbridge, which is based in Calgary, Alberta, provides energy transportation, distribution and related services in North America and internationally. Enbridge is the ultimate parent of our general partner.

We are a geographically and operationally diversified partnership consisting of interests and assets relating to the midstream energy sector. As of December 31, 2006, our portfolio of assets include the following:

- Approximately 4,900 miles of crude oil gathering and transportation lines and 24.5 million Bbl of crude oil storage and terminaling capacity.
- Natural gas gathering and transportation lines totaling approximately 11,000 miles.
- Nine active natural gas treating and 17 active natural gas processing facilities with an aggregate capacity of approximately 1,800 million cubic feet per day, or MMcf/d.
- Trucks, trailers and railcars for transporting NGLs, crude oil and carbon dioxide.
- Marketing assets that provide natural gas supply, transmission, storage and sales services.

Enbridge Management is a Delaware limited liability company that was formed in May 2002 to manage our business and affairs. Under a delegation of control agreement, our general partner delegated substantially all of its power and authority to manage our business and affairs to Enbridge Management. The General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management is the sole owner of a special class of our limited partner interests, which we refer to as "i-units."

Our ownership at December 31, 2006 is comprised of the following:

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

BUSINESS STRATEGY

Our primary objective is to provide stable and sustainable cash distributions to our unitholders, while maintaining a relatively low investment risk profile. Our business strategies focus on creating value for our customers, which we believe is the key to creating value for our investors. To accomplish our objective, we focus on the following key strategies:

1. Expand existing core asset platforms

   - We intend to develop and acquire energy transportation assets and related facilities that are complementary to our existing systems. Our core businesses provide plentiful opportunities to achieve our primary business objectives.

2. Develop new asset platforms

   - We plan to develop new gathering, processing, transportation and storage assets to meet customer needs, by expanding capacity into new markets with favorable supply and demand fundamentals.

3. Focus on operational excellence

   - We will continue to operate our existing infrastructure to maximize cost efficiencies, provide flexibility for our customers and ensure the capacity is reliable and available when required. We will focus on safety, environmental integrity, innovation and effective stakeholder relations.

In our current environment, our primary focus is on expanding and developing our existing assets. We are placing relatively less emphasis on acquisitions than in prior years due to:

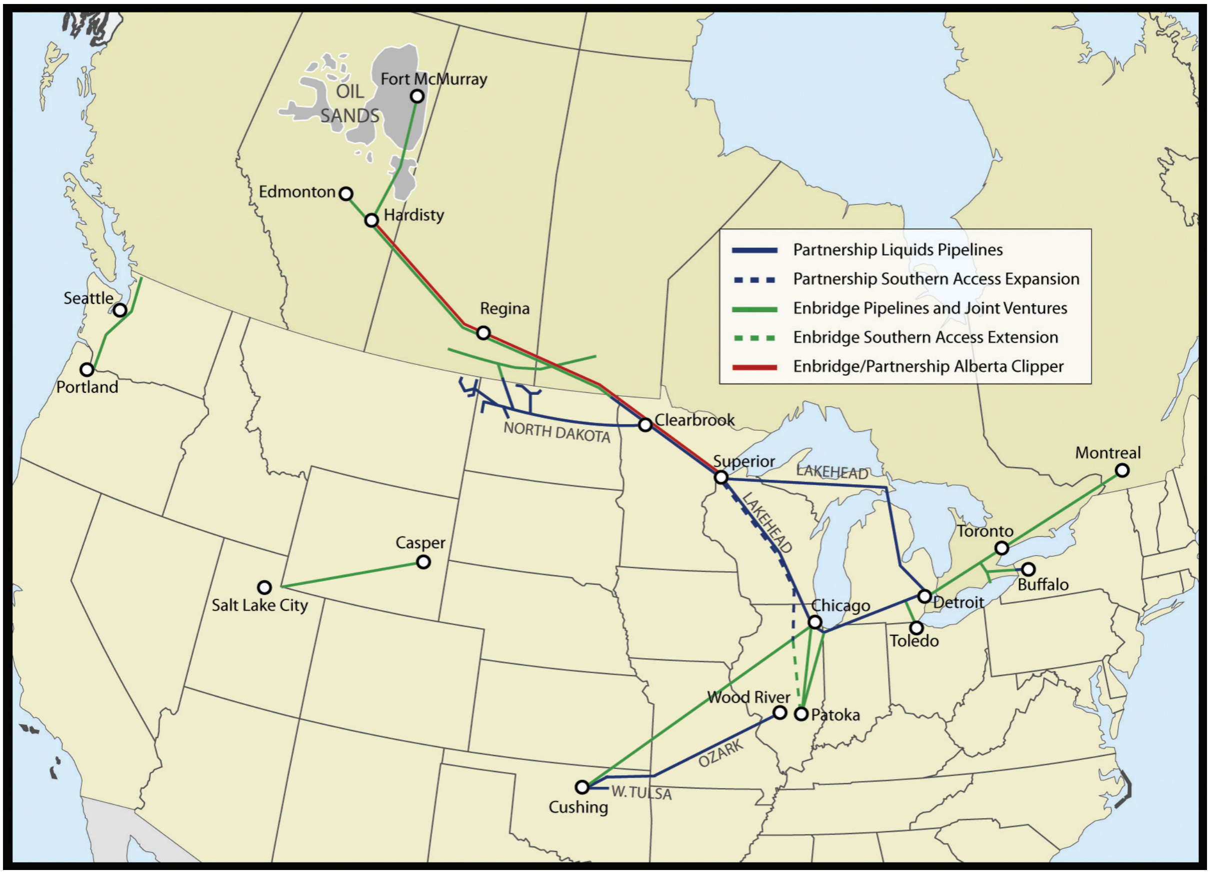
- Acquisition prices for the stable energy assets we seek have become inflated; and
- The expansion and diversification of our asset base over the past few years has created opportunities for internal growth projects that are expected to enhance the value of services we provide to our customers and returns to our investors.

While purchase prices remain high, our acquisitions will likely be limited to situations where we have natural advantages, through reduced costs or increased utilization of our services.

Our planned internal growth for both our liquids and natural gas businesses will require a significant investment of expansion capital over the next few years. While these major projects are under construction, our ability to increase distributions, while also funding these projects, is likely to be limited. Our outlook is premised on a number of major assumptions regarding the scope and timing of the projects, financing alternatives available to us and excludes the potential of significant acquisitions during the period. We expect our larger growth projects will be accretive to distributable cash flow when placed into service. These projects are discussed below in the respective business section.

Liquids

The following map presents the locations of our current Liquids systems assets:



This map depicts some assets owned by Enbridge to provide an understanding of how they interconnect with our Liquids systems.

Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2006 from the U.S. Department of Energy's Energy Information Administration, Canada supplied approximately 1.6 million barrels per day, or Bpd, of crude oil to the U.S., the largest source of U.S. imports. Of the Canadian crude oil moving into the U.S., about 69% was transported on the System, which is the primary pipeline from western Canada to the U.S. We are well positioned to develop additional infrastructure to deliver growing volumes of crude oil that are expected from the Alberta oil sands. With an estimated $82 billion of active or planned projects in the Alberta oil sands, new production is expected to grow steadily during the next 5 years, with an additional 2.4 million Bpd of incremental supply available by 2015, according to the Canadian Association of Petroleum Producers, or CAPP.

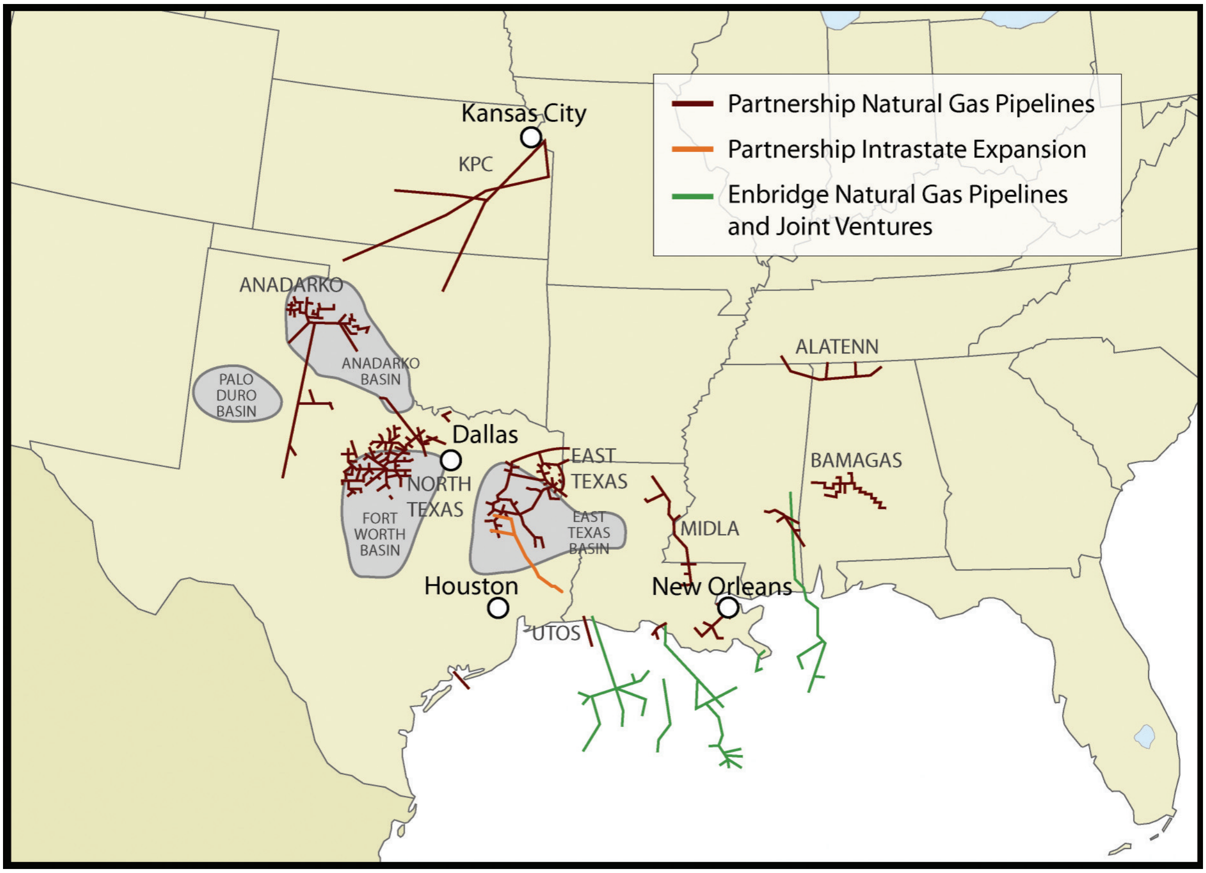
Our Southern Access project is the cornerstone of our mainline expansion initiatives to address the expected increase in supply of western Canadian crude oil. Our $1.3 billion project will provide an additional 400,000 Bpd of heavy crude oil capacity to the Chicago market and beyond by early 2009, with nearly half of this capacity available in early 2008. The design will also permit a further 800,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior. The Southern Access project involves new pipeline construction on our Lakehead system along with expansion on the Canadian portion of the pipeline by Enbridge.

Additionally, we and Enbridge are developing the Alberta Clipper project, which will involve construction of a 990 mile, 36-inch diameter, heavy crude oil pipeline from Hardisty, Alberta to Superior, Wisconsin with an initial capacity of 450,000 Bpd that is expandable to 800,000 Bpd. Our share of the cost of this project as currently proposed will be approximately $0.8 billion (excluding capitalized interest). Alberta Clipper is expected to be in-service in late 2009 to mid 2010. Regulatory applications will be filed once commercial terms are finalized, which is expected to occur in the first quarter of 2007.

Along with Enbridge, we are actively working with our customers to develop options that will allow Canadian crude oil to access new markets. The market strategy we are undertaking is to provide timely, economical, integrated transportation solutions to connect growing supplies of production from the Alberta oil sands to key refinery markets in the United States. The strategy involves further penetration into PADD II as well as entry into the vast refining center of the U.S. Gulf Coast. On April 28, 2005, the NEB approved two applications filed by Enbridge Pipelines to recover the costs for the extension of service to other markets via Enbridge's Spearhead pipeline and ExxonMobil's Pegasus pipeline through its Canadian tolls over the next 5 years. Through these initiatives, western Canadian crude oil is being delivered into Cushing, Oklahoma and Beaumont, Texas, respectively, since the first quarter of 2006. We benefit from these initiatives, as western Canadian crude oil is carried on our Lakehead system as far as Chicago and then transferred to these other pipelines to access these markets.

Natural Gas

The following map presents the locations of our Natural Gas systems assets:



This map depicts some assets owned by Enbridge to provide an understanding of how they relate to our Natural Gas systems.

Our natural gas assets are primarily located in the U.S. Gulf Coast region, one of the most active natural gas producing areas in the United States. Three of our larger systems in Texas are located in basins that are experiencing consistent growth in natural gas land leases, drilling and production. These core basins are known as the East Texas basin, the Fort Worth Basin and the Anadarko basin. Our focus has been on acquiring assets with strong growth prospects located in these areas and then to continue to develop those prospects.

One of our key objectives is to become the premier midstream energy company in the U.S. Gulf Coast region. To achieve this end, the operations and commercial activities of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, our key strategy is to provide safe and reliable service at reasonable costs to our customers, to enhance our reputation with our customers and to improve our competitiveness for capturing new customers. From a commercial perspective, our focus is to improve the value of service to our customers by providing them with a greater value for their commodity. We intend to achieve this objective by increasing customer access to the natural gas markets. We have made significant progress on this objective by physically connecting a number of our systems. The objective is to be able to move significant quantities of natural gas from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana. From these market hubs, natural gas can be transported to consumers in the Midwest and Northeast United States. Our trucking operations are used to enhance the value of the NGLs produced at our processing plants by ensuring ready access to strategic markets. Our marketing business also helps maximize the value received for the natural gas we transport and purchase by identifying customers with consistent demand for natural gas.

The growth prospects in our core areas are primarily a result of strong commodity prices, rig utilization rates and improvements in technology to produce natural gas from tight sand and shale formations. As a result, many expansions and extensions have been made on three of our main gathering and processing systems in Texas, including well-connects, processing plant re-activations, new plant construction, added compression, new pipelines and treating plant re-activations. During April 2006, we purchased $33 million of additional natural gas gathering and processing assets in East Texas, which we have integrated with our existing East Texas assets.

We continue to work closely with our customers to provide natural gas transportation solutions to avoid shut-in natural gas production from insufficient transportation capacity. During 2005, we completed construction of a new 500 MMcf/d intrastate transportation pipeline to carry increased volumes of natural gas to the pipeline hub at Carthage, Texas. Carthage access is important because it offers a number of connections to interstate pipelines, which tend to support more favorable natural gas prices for our customers. In January 2006, we announced a $610 million expansion and extension of our East Texas system. This project is required to handle the strong growth occurring in East Texas natural gas production, particularly from the Bossier Sands and other regional producing formations. We coordinated extensively with our customers to develop and enhance access for growing Texas natural gas production to major markets in southeast Texas. We have firm volume commitments and acreage dedications which we believe will approximate 550 MMcf/day, of the 700 MMcf/day of capacity, by the end of 2007. The project is designed to be expandable and is positioned for potential upstream and downstream extension.

BUSINESS SEGMENTS

We conduct our business through three business segments:

- Liquids;
- Natural Gas; and
- Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from external customers, operating income and total assets for each segment, refer to Note 16 of our consolidated financial statements.

Liquids Segment

Lakehead system

The Lakehead system consists primarily of a crude oil and liquid petroleum common carrier pipeline and terminal assets in the Great Lakes and Midwest regions of the United States. This system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. The System, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The System serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. Through its interconnection with the Enbridge system, the Lakehead system is well positioned to capitalize on expected increases in crude oil supplies from previously announced heavy crude oil and oil sands projects in the Province of Alberta, Canada.

Our Lakehead system is a FERC-regulated interstate common carrier pipeline system. The Lakehead system spans a distance of approximately 1,900 miles, and consists of approximately 3,500 miles of pipe with diameters ranging from 12 inches to 48 inches, 59 pump station locations with a total of approximately 768,000 installed horsepower and 62 crude oil storage tanks with an aggregate working capacity of approximately 10.8 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 59 crude oil commodities including light, medium and heavy crude oil (including bitumen, which is a naturally occurring tar-like mixture of hydrocarbons), condensate and NGLs.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2006, approximately 30 shippers tendered crude oil and liquid petroleum for delivery through the Lakehead system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Lakehead system. Our customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. Our Lakehead system is well positioned as the primary transporter of western Canadian crude oil and continues to benefit from the growing production of crude oil from the Alberta oil sands. Similar to U.S. domestic conventional crude oil production, western Canada's conventional crude oil production is declining. Over the last several years, development of the Alberta oil sands resource has more than offset declining conventional production. The NEB estimated that total WCSB 2006 production averaged approximately 2.3 million Bpd compared with 2.2 million bpd in 2005. WCSB crude oil production is comparable with production from key OPEC members Kuwait and Venezuela.

Remaining established conventional oil reserves in western Canada were estimated to be approximately 3.8 billion barrels at the end of 2005. During 2005, the latest period for which data is available, approximately 105 percent of conventional production was replaced with reserve additions. Remaining established reserves from the Alberta oil sands as of the end of 2005, stand at approximately 174 billion barrels. Combined conventional and oil sands established reserves of approximately 179 billion barrels compares with Saudi Arabia's proved reserves of approximately 260 billion barrels.

According to CAPP, an estimated $46 billion has been spent on oil sands development from 1996 through 2005. A survey of CAPP members and oil sands developers estimate that oil producers may spend an additional $82 billion by 2016, including all announced and planned oil sands projects. Although it is unlikely that all projects will proceed as planned, the investment already in place and the number and size of companies involved provides strong evidence of ongoing oil sands industry expansion. CAPP estimates future production from the Alberta oil sands will increase by more than 2.4 million barrels per day by 2015 based on a subset of currently approved applications and announced expansions.

The near-term growth in crude oil supply comes from the completion and consolidation of major expansion projects at existing synthetic crude oil upgraders and growth of bitumen production from both existing and new SAGD facilities currently under construction. Over the next year, synthetic crude oil production capacity is expected to increase by approximately 83,000 Bpd at the existing plants.

Syncrude completed a 100,000 Bpd Stage 3 expansion over the past year, increasing total production capacity to 350,000 Bpd. However, the new Stage 3 coker suffered from a number of start-up issues that prevented Syncrude from attaining full utilization of its production capacity. Syncrude's next expansion will de-bottleneck the current system to increase synthetic production by approximately 40,000 Bpd to approximately 390,000 Bpd by 2011.

Suncor completed its 35,000 Bpd expansion in late 2005 resulting in total upgrading capacity of 260,000 Bpd. Average synthetic production from the upgrader was 253,000 Bpd in 2006. Suncor also received conditional approval from the AEUB for its proposed Voyageur expansion, which will increase synthetic production capacity to 500,000 Bpd by 2012.

The Athabasca Oil Sands Project, or AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Western Oil Sands L.P. (20%), is another oil sands project that reached full production capacity in 2004. The AOSP project moved forward with the AEUB's conditional approval of the proposed AOSP Expansion 1 project. The AOSP Expansion 1 project aims to achieve an expansion from the current capacity of 165,000 Bpd to more than 255,000 Bpd by 2010.

Over the next two years, unblended bitumen production is expected to start, or increase, from more than ten individual projects that are coming on line. Notable projects include the expansions at Canadian Natural's Wolf Lake/Primrose area, ConocoPhillips' Surmont, Devon's Jackfish, EnCana's Foster Creek and Christiana Lake, Husky's Sunrise, Suncor's Firebag and Total's Josyln project. Based on the AEUB forecast, unblended bitumen production is expected to increase by roughly 60,000 Bpd by the end of 2007, more than offsetting the decline in conventional crude production.

Although the crude oil and liquid petroleum delivered through the Lakehead system primarily originates in oilfields in western Canada, the Lakehead system also receives approximately five percent of its receipts from domestic sources including:

- U.S. production at Clearbrook, Minnesota through a connection with the North Dakota system;
- U.S. production at Lewiston, Michigan; and
- both U.S. and offshore production in the Chicago area.

Based on forecasted growth in western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, Lakehead system deliveries are expected to average 1.64 million Bpd in 2007 compared with 1.52 million Bpd in 2006. The estimated deliveries for 2007 are part of a forecast representing forward-looking information and is subject to risks, uncertainties, and factors beyond our control.

Our ability to increase deliveries and to expand our Lakehead system in the future will ultimately depend upon numerous factors. The investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, and availability of markets for produced crude. Higher crude oil production from the WCSB should result in higher deliveries on the Lakehead system. Deliveries on the Lakehead system are also affected by periodic maintenance, turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

We expect the demand for WCSB crude oil production will continue to increase in PADD II. PADD II refinery configurations and crude oil requirements continue to be an attractive market for western Canadian supply. According to the U.S. Department of Energy's Energy Information Administration, 2006 demand for crude oil in PADD II remained relatively unchanged from 2005 with an average of 3.3 million Bpd. At the same time, production of crude oil within PADD II increased marginally by 13,000 Bpd to 456,000 Bpd. With the proximity of the WCSB to PADD II, the availability of capacity on the Lakehead system and limited alternative markets for WCSB production, we expect deliveries on the Lakehead system to increase along with increases in WCSB supply. Based on our industry survey, we expect refineries in the PADD II market to compete aggressively with new markets for access to the growing supply from the WCSB.

In conjunction with Enbridge, we announced the 400,000 Bpd Southern Access expansion project in 2005. The first stage of the U.S. portion of the expansion on Lakehead will add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. The first stage includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in early 2009. Completion of the total Southern Access expansion project will create a new 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

On March 16, 2006, the Federal Energy Regulatory Commission ("FERC") approved an Offer of Settlement with respect to rate principles for the Southern Access expansion, which were negotiated with CAPP. In July 2006, support from shippers and CAPP was obtained to increase the diameter of the new pipeline segment of the project from 36 inches to 42 inches. The incremental capital cost of the larger diameter pipe is currently estimated at approximately $157 million, bringing our total estimated portion of the costs to approximately $1.3 billion. The larger diameter will not provide increased capacity in the near term but does increase the ultimate expansion capacity of the line from 800,000 Bpd to 1,200,000 Bpd with additional pumping horsepower. This improves future expansion opportunities for our Lakehead system. Return on the incremental capital for the larger diameter pipe will be deferred until the additional capacity is required by shippers (see discussion of Alberta Clipper project below). In the interim, shippers will absorb all the incremental operating costs of the larger diameter pipe but will benefit from reduced power costs at higher throughput levels. Delivery of line pipe to the rights-of-way has commenced to ensure full completion in early 2009.

In July 2006, Enbridge announced that it had received support from shippers and CAPP for its 36-inch diameter, 400,000 Bpd Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project will be undertaken by Enbridge; however, our Lakehead system will benefit from incremental volumes moving through the system to connect with this extension. A FERC Offer of Settlement was filed on September 1, 2006. On December 8, 2006, the FERC rejected the rolled in rate design contained in the Offer of Settlement. However, support for the project remains very strong and Enbridge is preparing an alternative tolling structure to address the initial opposition from the intervening parties. It is expected that a second application will be filed with the FERC in the first quarter of 2007 to allow the project to continue on schedule, with a 2009 in-service date.

Based on forecasts of oil sands production growth prepared by Enbridge, as well as forecasts by CAPP, it is believed that there will be a need for additional export pipeline capacity out of western Canada over and above projects described above. Based on this analysis, as well as interest expressed by shippers, we and Enbridge are developing the Alberta Clipper project. This project will involve construction of a 990-mile, 36-inch diameter, heavy crude line from Hardisty, Alberta to Superior, Wisconsin with an initial capacity of 450,000 Bpd that is expandable to 800,000 Bpd. Our share of the cost of this project as currently proposed will be approximately $0.8 billion (in 2006 dollars, excluding capitalized interest).

Based on discussions with our shippers the preference is for the Alberta Clipper Project to be a common carrier pipeline fully integrated with the System for rate-making purposes. Alberta Clipper is expected to be in-service in late 2009 to mid 2010. Regulatory applications will be filed once commercial terms are finalized, which we expect to occur in the first quarter of 2007.

During the first quarter of 2006, Enbridge completed the reversal of its Spearhead Pipeline that now flows from Chicago, Illinois to Cushing, Oklahoma, with a capacity of 125,000 Bpd. In March 2006, the first western Canadian crude oil was delivered through this system into the major oil hub at Cushing. Our Lakehead system benefits from the reversal of the Spearhead pipeline as western Canadian crude oil is carried on our Lakehead system as far as the Chicago region and then transferred to the Spearhead pipeline.

In April 2006, ExxonMobil announced it had completed the reversal of two of its crude oil pipelines allowing up to 66,000 Bpd of Canadian crude oil to flow from Patoka, Illinois to the U.S. Gulf Coast. The pipeline is linked to our Lakehead system at Chicago via the Mustang Pipe Line LLC system to Patoka, Illinois. The Mustang system is 30% owned by an affiliate of Enbridge. ExxonMobil has received firm commitments from Canadian shippers for an average of 50,000 Bpd of capacity on the lines from Patoka, to Nederland, Texas for the next five years. The connection of our Lakehead system with this new market should also support increased throughput on our Lakehead system; however, the reversed ExxonMobil system is also capable of transporting western Canadian crude oil moved via other competing pipelines into the Patoka market.

Competition. Our Lakehead system, along with the Enbridge system, is the main crude oil export route from the WCSB. WCSB production in excess of western Canadian demand moves on existing pipelines into the Midwest area of the United States (PADD II), the Rocky Mountain states (PADD IV), the Anacortes area of Washington State (PADD V), and the U.S. Gulf Coast (PADD III). In each of these regions, WCSB crude oil competes with local and imported crude oil. As local crude oil production declines and refineries demand more imported crude oil, imports from the WCSB should increase.

In 2005, PADD II imported approximately 1 million Bpd of Canadian crude. For 2006, the latest data available shows that PADD II total demand was 3.3 million Bpd while it produced only 456,000 Bpd, and thus imported 2.85 million Bpd. For the first ten months of 2006, PADD II imported approximately 1.1 million Bpd of crude oil from Canada, and the remainder was imported from PADD III and offshore sources through the U.S. Gulf Coast. Of the crude oil imported from Canada, 2006 actual volumes transported on our Lakehead system to PADD II averaged 1.1 million Bpd including deliveries to destinations in PADD II, and to other pipeline systems with PADD III destinations. Lakehead system deliveries of Canadian crude oil to PADD II increased by approximately 152,000 Bpd in 2006, a 16% increase from 2005 volumes. Total deliveries on our Lakehead system averaged 1.52 million Bpd in 2006, meeting approximately 71 percent of Minnesota refinery capacity; 62 percent of the greater Chicago area; and 82 percent of Ontario's refinery demand.

Considering all of the pipeline systems that transport western Canadian crude oil out of Canada, the System transported approximately 69 percent of the total western Canadian crude oil exports in 2006 to the United States. The remaining production was transported by systems serving the British Columbia, PADD IV and PADD V markets.

Given the expected increase in crude oil production from the Alberta oil sands over the next 10 years, alternative transportation proposals have been presented to crude oil producers. These proposals range from expansions of existing pipelines currently transporting western Canadian crude oil to new pipelines and extensions of existing pipelines. These proposals are in various stages of development, with some at the concept stage and others that are proceeding with regulatory approval. Some of these proposals could be in direct competition with our Lakehead system.

Enbridge has proposed construction of the Gateway Pipeline in the 2012 to 2014 timeframe, which includes both a condensate import pipeline and a petroleum export pipeline. The condensate line would transport imported diluent from Kitimat, British Columbia to the Edmonton, Alberta area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat and would compete with our Lakehead system for production from the Alberta oil sands.

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

The following provides an overview of other proposals put forth by competitor pipeline companies that are not affiliated with Enbridge:

- The construction of a new 24-inch pipeline alongside an existing pipeline which begins in Clearbrook, Minnesota and transports western Canadian crude oil to St. Paul, Minnesota. This expansion will have 165,000 Bpd initial capacity and 350,000 Bpd ultimate capacity. Construction is planned for summer 2007, with a completion date in 2008. While throughput on our Lakehead system would benefit from this expansion, volumes moving on our Lakehead system would only be negatively impacted if the Wood River to St. Paul pipeline were to be reversed.

- The expansion of an existing pipeline that runs from Alberta to British Columbia and Washington state. The first phase of this expansion to add 35,000 Bpd of capacity was approved by the NEB in 2005 and is expected to be in service in 2007. The second phase received NEB approval in October 2006, and would further increase capacity by another 40,000 Bpd by 2009. Additional phases have also been proposed which would add substantial additional capacities.

- Construction of a new 435,000 Bpd crude oil pipeline from Hardisty, Alberta to Wood River and Patoka, with an expected in-service date of late 2009. This proposal has support of long-term contracts for a total of 340,000 Bpd. The sponsor company filed applications with the NEB in June 2006 to convert part of its mainline gas transmission facilities, and in December 2006, for approval to operate and construct facilities in Canada. Public hearings on the gas line transfer application were held in mid-November 2006 and in early 2007 the NEB approved transfer of the gas transmission facilities to crude oil service, although additional approvals will be required from United States and Canadian regulatory authorities before the project can proceed. The company is also proposing an expansion to 590,000 Bpd and an extension to Cushing, Oklahoma. An open season will be held in the early part of 2007 to determine shipper interest and a variety of regulatory approvals will be required in the United States at state and local levels before the proposal can proceed.

- Construction of a new crude oil pipeline from northern Alberta directly to the U.S. Gulf Coast. This conceptual pipeline proposal is subject to shipper support and regulatory approval.

These competing alternatives for delivering western Canadian crude oil into the United States and other markets could erode shipper support for further expansion of our Lakehead system beyond the Southern Access Expansion and the Alberta Clipper Project. They could also affect throughput on and utilization of the System. However, the Lakehead and Enbridge systems offer significant cost savings and flexibility advantages, which are expected to continue to favor the systems as the preferred alternative for meeting shipper transportation requirements to the Midwest United States.

The following table sets forth average deliveries per day and barrel miles of our Lakehead system for each of the periods presented.

	Deliveries				
	2006	2005	2004	2003	2002
	(thousands of Bpd)				
United States					
Light crude oil	327	241	275	258	266
Medium and heavy crude oil	872	791	785	741	665
NGL	5	4	4	4	6
Total United States	1,204	1,036	1,064	1,003	937
Ontario					
Light crude oil	160	146	174	174	171
Medium and heavy crude oil	63	59	81	68	83
NGL	90	98	103	109	111
Total Ontario	313	303	358	351	365
Total Deliveries	1,517	1,339	1,422	1,354	1,302
Barrel miles (billions per year)	400	338	367	345	341

Mid-Continent system

Our Mid-Continent system, which we acquired in the first quarter of 2004, is located within the PADD II district and is comprised of our Ozark pipeline, our West Tulsa pipeline and storage terminals at Cushing and El Dorado, Kansas. It includes over 480 miles of crude oil pipelines and 12.8 million barrels of crude oil storage capacity. Our Ozark pipeline transports crude oil from Cushing to Wood River where it delivers to ConocoPhillips' Wood River refinery and interconnects with the WoodPat Pipeline, and the Wood River Pipeline, each owned by unrelated parties. Our West Tulsa pipeline moves crude oil from Cushing to Tulsa, Oklahoma where it delivers to Sinclair Oil Corporation's Tulsa refinery.

The storage terminals consist of 97 individual storage tanks ranging in size from 55,000 to 575,000 barrels. We expect to add 11 new tanks during 2007 to our existing storage facilities in Cushing, which will increase our crude oil storage capacity to 16.7 million barrels by the end of 2007. A portion of the storage facilities are used for operational purposes while we contract the remainder of the facilities with various crude oil market participants for their term storage requirements. Contract fees include fixed monthly capacity fees as well as utilization fees, which we charge for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. Our Mid-Continent system operates under month-to-month transportation arrangements and both long-term and spot storage arrangements with its shippers. During 2006, approximately 30 shippers tendered crude oil for service by the Mid-Continent system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average daily deliveries on the system were 236,000 Bpd for 2005 and 244,000 Bpd for 2006.

Supply and Demand. The Mid-Continent system is positioned to capture increasing near-term demand for imported crude oil from west Texas and the U.S. Gulf Coast as well as third-party storage demand. In 2006, PADD II imported 3.3 million barrels per day from outside of the PADD II region. The Lakehead system supplied roughly 1.1 million barrels per day of crude from Canada leaving 2.2 million barrels per day imported from PADDs III and IV as well as offshore sources. We expect the gap between local supply and demand for crude oil in PADD II to continue to widen, encouraging imports of crude oil from Canada, PADD III and foreign sources.

Competition. Our Ozark pipeline system currently serves an exclusive corridor between Cushing and Wood River. However, refineries connected to Wood River have crude supply options available from Canada via the Lakehead system, with a connection to the Mustang pipeline, an Enbridge affiliated system, and through a third party pipeline, which runs from western Canada and PADD IV. These same refineries also have access to U.S. Gulf Coast and foreign supply through the Capline pipeline system, which is owned by an unrelated group of five owners. In addition, refineries located east of Patoka with access to crude through the Ozark system, also have access to west Texas supply through the Texas Gulf pipeline owned by third parties. The Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

In addition to movements into Wood River, crude oil in Cushing is transported to Chicago and El Dorado on third-party pipeline systems. With the reversal of the Spearhead pipeline, western Canadian crude oil moving on Spearhead is increasing the importance of Cushing as a terminal and pipeline origination area.

The storage terminals rely on demand for storage service from numerous oil market participants. Producers, refiners, marketers and traders rely on storage capacity for a number of different reasons: batch scheduling, stream quality control, inventory management, and speculative trading opportunities. Competitors to our storage facilities at Cushing include large integrated oil companies and other midstream energy partnerships.

North Dakota system

Our North Dakota system is a crude oil gathering and interstate transportation system servicing the Williston Basin in North Dakota and Montana. Its crude oil gathering pipelines collect crude oil from points near producing wells in approximately 36 oil fields in North Dakota and Montana. Most deliveries from the North Dakota system are made at Clearbrook, Minnesota, to the Lakehead system and to a third-party pipeline system. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long, with a capacity of approximately 90,000 to 95,000 Bpd. This is a 10,000 to 15,000 Bpd increase due to a recent successful hydrotest program and the addition of drag reducing agents at pumping stations along the pipeline. The North Dakota system also has 16 pump stations and 11 terminaling facilities with an aggregate working storage capacity of approximately 685,000 barrels. We are in the middle of a $70 million expansion of this system that we began in 2006 and expect to complete in phases throughout 2007, with the majority of the project beginning service in the second half of 2007. This expansion is necessary to meet increased crude oil production from the Montana and North Dakota region.

Customers. Customers of the North Dakota system include producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to the largest integrated oil companies.

Supply and Demand. Like the Lakehead system, the North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States, and the ability of crude oil producers to maintain their crude oil production and exploration activities.

Competition. Competitors of the North Dakota system include integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by the North Dakota system have alternative gathering facilities available to them or have the ability to build their own facilities.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transportation systems as well as trucking operations. We purchase and/or gather natural gas from the wellhead, deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission, or to wholesale customers such as power plants, industrial customers and local distribution companies.

Natural gas treating involves the removal of hydrogen sulfide, carbon dioxide, water and other substances from raw natural gas so that it will meet the standards for pipeline transportation. Natural gas processing involves the separation of raw natural gas into residue gas and NGLs. Residue gas is the processed natural gas that ultimately is consumed by end users. NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a process known as fractionation, and sold as their individual components, including ethane, propane, butanes and natural gasoline. At December 31, 2006, we have approximately 8,500 miles of gathering pipelines, nine treating plants and 17 processing plants, excluding plants that are inactive. Our treating facilities have a combined capacity exceeding 850 MMcf/d while the combined capacity of our processing facilities is over 950 MMcf/d.

Our natural gas segment consists of the following major systems:

- East Texas system: Includes approximately 2,900 miles of natural gas gathering and transportation pipelines, seven natural gas treating plants and four natural gas processing plants.
- Anadarko system: Consists of approximately 1,200 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle, one natural gas treating plant and four natural gas processing plants. The Anadarko system includes the Palo Duro system, which we acquired in March 2004.
- North Texas system: Includes approximately 4,200 miles of natural gas gathering pipelines and eight natural gas processing plants.
- Our transportation operations include four FERC-regulated natural gas interstate pipeline systems. Our four major FERC regulated systems are the KPC pipeline, Midla pipeline, AlaTenn pipeline and UTOS pipeline. Each of these natural gas pipeline systems typically consists of a natural gas pipeline, compression, and various interconnects to other pipelines that serve wholesale customers.
- Our transportation operations also include a number of smaller non-FERC regulated natural gas pipelines as well as trucking operations which are discussed below.

Customers. Customers of our natural gas pipeline systems include both purchasers and producers of natural gas. Purchasers include marketers and large users of natural gas, such as power plants, industrial facilities and local distribution companies. Producers served by our systems consist of small, medium and large independent operators and large integrated energy companies. We sell NGLs resulting from our processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

Our natural gas pipelines serve customers in the Gulf Coast and Mid-Continent regions of the United States. Customers include large users of natural gas, such as power plants, industrial facilities, local distribution companies, large consumers seeking an alternative to their local distribution company, and shippers of natural gas, such as natural gas producers and marketers.

Supply and Demand. Demand for our gathering, treating and processing services primarily depends upon the supply of natural gas reserves and the drilling rate of new wells. The level of impurities in the natural gas gathered also affects treating services. Demand for these services also depends upon overall economic conditions and the prices of natural gas and NGLs. Three of our larger systems are located in basins that continue to experience growth in natural gas drilling and production.

Our East Texas system is primarily located in the East Texas Basin. While production from most regions within this basin has remained flat for several years, the Bossier trend within the East Texas Basin continues to experience substantial growth. The Bossier trend is located on the western side of our East Texas system. Production in the Bossier trend has grown from under 390 MMcf/d in 1997 to over 1,300 MMcf/d during the first half of 2006. In the third quarter of 2006, we completed construction of our 120 MMcf/d Henderson natural gas processing facility on our East Texas system and acquired an 80-mile pipeline in April 2006, that is complimentary to our existing East Texas system and provided approximately 75,500 MMBtu/d of incremental volume. In addition the link between our North Texas and East Texas systems became fully operational during the third quarter of 2006. As expected, the completion of this connection has increased the utilization of our 500 MMcf/d intrastate pipeline that we placed in service in June 2005 on our East Texas system by providing additional market access to customers of our North Texas system. We also commenced a significant expansion of treating and processing capacity in the region, a significant portion of which is already operational with the remaining facilities expected to be complete in stages throughout 2007.

In an effort to address the strong growth in natural gas production occurring in East Texas, we initiated a $610 million expansion and extension of our East Texas system in early 2006, which we refer to as the Clarity project. The Clarity project is necessary to develop and enhance access for growing East Texas natural gas production to major markets in Southeast Texas and to avoid shut in of natural gas production that could result from insufficient natural gas pipeline transportation capacity. The extension and expansion of our East Texas System is expected to be completed in stages through 2007 and will provide increasing market options for customers. In addition, the Clarity project is designed to be expandable both upstream and downstream to meet growing demand for natural gas transportation capacity. We have firm volume commitments and acreage dedications which we believe will approximate 550 MMcf/day, of the 700 MMcf/d of capacity, by the end of 2007. The project is designed to be expandable and is positioned for potential upstream and downstream extension.

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale area within the Fort Worth Basin Conglomerate. The Fort Worth Basin Conglomerate is a mature zone that is experiencing slow production decline. In contrast, the Barnett Shale area is one of the most active natural gas plays in North America. While abundant natural gas reserves have been known to exist in the Barnett Shale area since the early 1980s, recent technological developments in fracturing the shale formation allows commercial production of these natural gas reserves. Since 1999 Barnett Shale production has risen from approximately 110 MMcf/d to over 1,800 MMcf/d in 2006, with the drilling of over 5,200 wells. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of Barnett Shale development. To accommodate anticipated growth in the region we have commenced construction of two new gas processing plants totaling approximately 75 MMcf/d of capacity and related upstream facilities. These facilities are expected to become operational in the second and fourth quarters of 2007.

Our Anadarko system is located within the Anadarko basin and continues to experience considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. We are continuing to make progress in increasing processing capacity in the region from 230 MMcf/d at December 31, 2005 to approximately 440 MMcf/d to accommodate the volume growth. In 2006 we expanded our existing Zybach processing facility to a capacity of 150 MMcf/d of natural gas from the initial capacity of approximately 105 MMcf/d when we placed the plant in service in April 2005. During

2007, to meet the continuing demands resulting from rapid development in the Anadarko basin, we expect to increase the processing capacity of our Anadarko system by approximately 155 MMcf/d. We will also continue to add significant field compression to accommodate the volume growth on this system.

We intend to expand our natural gas gathering and processing services primarily through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value for our existing assets.

Our natural gas pipelines generally serve different geographical areas, with differing supply and demand characteristics in each market. We believe that demand and competition for natural gas in the areas served by our natural gas assets will generally remain strong as a result of being located in areas where industrial, commercial or residential growth is occurring. The greatest demand for services in the markets served by our natural gas assets occurs in the winter months.

The table below indicates the capacity in MMcf/d of the transportation and wholesale customer pipelines with firm transportation contracts as of December 31, 2006 and the amount of capacity that is reserved under those contracts as of that date.

Major System	Capacity MMcf/d	Percentage Reserved Under Contract as of December 31, 2006
UTOS system	1,200	0%
Midla system	200	74%
AlaTenn system	200	27%
KPC system	160	96%
Bamagas system	450	61%

Our UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term reserve capacity. The UTOS system's average daily throughput during 2006 was 181,000 MMBtu/d. The FERC approved our negotiated settlement with UTOS shippers, keeping our current rates in effect under our 2003 FERC Order, through 2006. On December 7, 2006, we filed an application for an extension of that Order to keep the settlement rates in effect for an additional 3-year term that was subsequently approved on February 21, 2007.

Our Midla, AlaTenn and Bamagas systems primarily serve industrial corridors and power plants in Louisiana, Alabama and Tennessee. Industries in the area include energy intensive segments of the petrochemical and pulp and paper industries. We market the unused capacity on these systems under both short-term firm and interruptible transportation contracts and long-term firm transportation contracts. These systems are located in areas where opportunities exist to serve new industrial facilities and to make delivery interconnects to alleviate capacity constraints on other third-party pipeline systems. As of December 31, 2006, approximately 74% of contracted capacity of the Midla system and approximately 16% of the AlaTenn system is under contract to our marketing business.

The Bamagas system in northern Alabama is contiguous with our AlaTenn system and serves two power plants that are indirectly owned by Calpine Corporation ("Calpine"). In December 2005, Calpine declared bankruptcy and is in reorganization however, Calpine has continued to perform under the terms of its agreement with Bamagas and we continue to monitor the proceedings. Refer to the discussion included in Item 7. Management's Discussion and Analysis of Financial Condition in our Natural Gas segment included in the Future Prospects section entitled Other Matters of this report for more information about Calpine's bankruptcy filling.

Our KPC system has 84% of its capacity reserved under firm transportation contracts extending through 2009 and an additional 12% of its capacity reserved under contracts extending through 2017. The KPC system's primary customers are local distribution companies.

Our long-term financial condition depends on the continued availability of natural gas for transportation to the markets served by our systems. Existing customers may not extend their contracts if the availability of natural gas from the Mid-continent and Gulf Coast producing regions was to decline and if the cost of transporting natural gas from other producing regions through other pipelines into the areas we serve were to render the delivered cost of natural gas uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Competition. Competition from other pipeline companies is significant in all the markets we serve. Competitors of our gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. Some of these competitors are substantially larger than we are. Competition for the services we provide varies based upon the location of gathering, treating and processing facilities. Most natural gas producers and owners have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On the sour gas systems, such as our East Texas system, competition is more limited due to the infrastructure required to treat sour gas.

Competition for customers in the marketing of residue gas is based primarily upon the price of the delivered gas, the services offered by the seller and the reliability of the seller in making deliveries. Residue gas also competes on a price basis with alternative fuels such as crude oil and coal, especially for customers that have the capability of using these alternative fuels, and on the basis of local environmental considerations. Competition in the marketing of NGLs comes from other NGL marketing companies, producers, traders, chemical companies and other asset owners.

Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers we serve have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines. In addition, a number of new interstate natural gas pipelines are being constructed in areas currently served by some of our intrastate and interstate pipelines. When completed, these new pipelines may compete for customers with our existing pipelines.

Trucking and Liquids Marketing Operations

We also include our trucking and liquids marketing operations in our Natural Gas segment. Trucking and liquids marketing operations include the transportation of NGLs, crude oil and carbon dioxide by truck and railcar from wellheads and treating, processing and fractionation facilities and to wholesale customers, such as distributors, refiners and chemical facilities. In addition, our trucking and liquids marketing operations resell these products. A key component of our business is ensuring market access for the liquids extracted at our processing facilities. On average this accounts for approximately 35% of the volume transported by our trucking and liquids marketing business and is a major source of its growth in this area.

Our services are provided using trucks, trailers and rail cars, product treating and handling equipment and NGL storage facilities. In addition, our CO_2 plant, with 250 tons per day of capacity, takes excess CO_2 from hydrogen producers which we then sell to a variety of customers. At the end of 2004, we took 50% ownership of an underground propane storage facility in Petal, Mississippi, which augments the services we provide to our customers in the region. The total capacity of this facility is 5.6 million Bbls which increases our storage capabilities.

In late 2005, we began increasing our truck fleet by approximately 25 percent to meet the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as to capitalize on the opportunity to better serve our Gulf Coast customers.

Customers. Most of the customers of our trucking and liquids marketing operations are wholesale customers, such as refineries and propane distributors. Our trucking and liquids marketing operations also market products to wholesale customers such as petrochemical plants.

Supply and Demand. The areas served by our trucking and liquids marketing operations are geographically diverse, and the forces that affect the supply of the products transported vary by region. Crude oil and natural gas prices and production levels affect the supply of these products. The demand for services is affected by the demand for NGLs and crude oil by large industrial refineries, and similar customers in the regions served by this business.

Competition. Our trucking and liquids marketing operations have a number of competitors, including other trucking and railcar operations, pipelines, and, to a lesser extent, marine transportation and alternative fuels. In addition, the marketing activities of our trucking and liquids marketing operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment's primary objective is to maximize the value of the gas purchased by our gathering systems and the throughput on our gathering and intrastate wholesale customer pipelines. To achieve this objective, our Marketing segment transacts with various counterparties to provide natural gas supply, transportation, balancing, storage and sales services.

Since our gathering and intrastate wholesale customer pipeline assets are geographically located within Texas, Oklahoma, Alabama and Louisiana, the majority of activities conducted by our Marketing segment are focused within these areas.

Customers. Natural gas purchased and sold by our Marketing segment is sold to industrial, utility and power plant end use customers. In addition, gas is sold to marketing companies at various market hubs. These sales are typically priced based upon a published daily or monthly price index. Sales to end-use customers incorporate a pass-through charge for costs of transportation and additional margin to compensate us for associated services.

Supply and Demand. Supply for our Marketing business depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our Natural Gas segment. Demand is typically driven by weather-related factors with respect to power plant and utility customers, and industrial demand.

Our Marketing business uses third-party storage capacity to balance supply and demand factors within its portfolio. Marketing pays third-party storage facilities and pipelines for the right to store gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities. Due to the increased volumes from our gathering assets, our Marketing business leases third-party pipeline capacity downstream from our Natural Gas assets under firm transportation contracts following specific, controlled guidelines. This capacity is leased for various lengths of time and rates that allows our Marketing business to diversify its customer base by expanding its service territory. Additionally, this transportation capacity provides assurance that our gas will not be shut in due to capacity constraints on downstream pipelines.

Competition. Our Marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and gas producers, independent aggregators and regional marketing companies.

REGULATION

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The Lakehead, North Dakota, and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the ICA. As common carriers in interstate commerce, these pipelines provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. The ICA generally requires us to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier pipelines, as well as the rules and regulations governing these services.

The ICA gives the FERC the authority to regulate the rates we charge for service on our interstate common carrier pipelines. The ICA requires, among other things, that such rates be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate the rates to determine if they are just and reasonable. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund with interest the increased revenues in excess of the amount that would have been collected during the term of the investigation at the rate properly determined to be lawful. The FERC also may investigate, upon complaint, or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992, or EP Act, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment, or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365 day period, to be just and reasonable under the ICA (i.e., "grandfathered"). The EP Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show, 1) that it was contractually barred from challenging the rates during the relevant 365 day period; 2) that there has been a substantial change after the date of enactment of the EP Act in the economic circumstances of the pipeline or in the nature of the services that were the basis for the rate; or 3) that the rate is unduly discriminatory or unduly preferential.

The FERC has determined that the Lakehead system rates are not covered by the grandfathering provisions of the EP Act because they were subject to challenge prior to the effective date of the statute. We believe that the rates for the North Dakota and Ozark systems should be found to be largely covered by the grandfathering provisions of the EP Act.

The EP Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines, and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted an indexing rate methodology for petroleum pipelines. Under the regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels may be protested, but such protests must show that the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling, although a pipeline is not required to reduce its rate below the level grandfathered under the EP Act. Under Order No. 561, a pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

Under Order No. 561, the original inflation index adopted by the FERC was equal to the annual change in the PPI-FG minus one percentage point. The index was subject to review every five years. Rates were then subject to an annual adjustment, based upon changes in the PPI-FG minus 1%, in order to accurately reflect the actual cost changes experienced by the oil pipeline industry. In December 2000, as part of the FERC's five-year review of the oil-pricing index (July 2001 through June 2006), the FERC concluded that the PPI-FG accurately reflected the actual cost changes experienced by the industry. In February 2003 the FERC issued an Order on Remand concluding that for the current five-year period, the oil-pricing index should be the PPI-FG. In order to calculate the 2003 ceiling rate levels, oil pipelines were permitted to use the PPI-FG adjustment as though it had been in effect since 2001. As of July 2006, the index increased to equal PPI-FG plus 1.3 percentage points, resulting in an index of 6.1485%. The FERC attributed the higher index formula to increases in industry costs from the imposition of new safety and environmental regulatory obligations, voluntary security measures, and higher energy costs. The FERC will continue, over the next five years, to review the oil pipeline index and monitor whether the current rate in place still reflects the actual cost changes experienced by the oil pipeline industry.

Allowance for Income Taxes in Rates

In a 1995 decision involving our Lakehead system, which we refer to as the *Lakehead ruling*, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. A subsequent appeal of the *Lakehead ruling* was resolved by settlement and therefore was not adjudicated. In another FERC proceeding involving SFPP, the FERC initially relied on its previous *Lakehead ruling* to hold that SFPP could not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding appealed the FERC's orders to the United States Court of Appeals for the District of Columbia Circuit, or the D.C. Circuit Court. On July 20, 2004, in *BP West Coast Products LLC v. FERC* (No. 99-1020), which we refer to as the *BP West Coast decision*, the D.C. Circuit Court issued a decision upholding certain aspects of the FERC's orders regarding the SFPP case, but vacating the FERC's ruling regarding the proper tax allowance for SFPP. The D.C. Circuit Court rejected the FERC's rationale for its *Lakehead ruling* and remanded the case to the FERC for further proceedings.

In the wake of the *BP West Coast* decision, the FERC initiated a notice and comment process to address tax allowance issues across a range of industries. We and many other companies commented on the proceeding. On May 4, 2005, the FERC issued a policy statement on income tax allowances, in which it reinstated its earlier policy of providing a full tax allowance on all partnership and similar legal interests in regulated companies if the owner of that interest has an actual or potential tax liability on the income earned through that interest. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. On December 16, 2005, FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16 order have been appealed to the D.C. Circuit Court, and rehearing requests have been filed with respect to the

December 16 order. As well as the SFPP decision, which is currently on appeal, there are two other cases with regards to tax allowance pending in the D.C. Circuit Court including Exxon Mobil Oil Corporation v. FERC and CAPP v. FERC.

The D.C. Circuit Court heard oral arguments on these cases on December 12, 2006. A decision is expected by April 2007. At this time, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service arrangements. Whether the income tax allowance policy is ultimately upheld or modified on judicial review, could affect the tariffs of FERC-regulated pipelines.

A related issue is whether the FERC's income tax allowance policy can be relied upon by shippers as a substantial change in circumstances sufficient to remove the grandfathering protection under the EP Act from an oil pipeline's rates. The FERC determined in the SFPP case that its policy statement on income tax allowances does not represent a change from its pre-EP Act policy and therefore, cannot affect grandfathering of rates, a position that is still potentially subject to further judicial review.

At this time, the effect of the FERC's policy statement on income tax allowances on us is uncertain. The tariff rates on our common carrier interstate liquids pipelines have been established under a variety of different circumstances including settlements and tariff indexing. It is anticipated that a change in the income tax allowance policy would only impact those rates that were established after indexing. Even with the indexed rates, the income tax allowance is only one of many elements supporting our pipeline rates for service. Accordingly, we cannot predict with certainty what rates we will be allowed to charge in the future, or the potential impact on us of a change in FERC's policy statement on income tax allowances.

We believe that the rates we charge for transportation services on our interstate common carrier liquids pipelines are just and reasonable under the ICA. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Accounting for Pipeline Assessment Costs

In June 2005, the FERC issued an order in Docket AI05-1 describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation's Office of Pipeline Safety. The order took effect on January 1, 2006. Under the order, FERC-regulated companies are generally required to recognize costs incurred in performing pipeline assessments that are part of a pipeline integrity management program as maintenance expense in the period in which the costs are incurred. Costs for items such as rehabilitation projects designed to extend the useful life of the system can continue to be capitalized to the extent permitted under the existing rules. The FERC denied rehearing of its accounting guidance order on September 19, 2005.

We have historically capitalized first time in-line inspection programs, based on previous rulings by the FERC. In January 2006, we began expensing all first-time internal inspection costs for all our pipeline systems, whether or not they are subject to FERC regulation on a prospective basis. We will continue to expense secondary internal inspection tests consistent with our previous practice. Refer to Note 2: Summary of Significant Accounting Policies included in our consolidated financial statements beginning at page F-1 of this annual report on Form 10-K.

Regulation by the FERC of Interstate Natural Gas Pipelines

Our AlaTenn, Midla, KPC and UTOS systems are interstate natural gas pipelines regulated by the FERC under the NGA, and the NGPA. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides service to its customers. In addition, the FERC's authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- conduct and relationship with energy affiliates; and
- various other matters.

Tariff changes can only be implemented upon approval by the FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with the FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If the FERC determines that a proposed change is just and reasonable as required by the NGA, the FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if the FERC determines that a proposed change may not be just and reasonable as required by the NGA, then the FERC may suspend such change for up to five months and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

In November 2003, the FERC issued Order 2004 governing the Standards of Conduct for Transmission Providers (including natural gas interstate pipelines). These standards provide that interstate pipeline employees engaged in natural gas transmission system operations must function independently from any employees of their energy affiliates and marketing affiliates and that an interstate pipeline must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and cannot operate its transmission system to benefit preferentially, an energy or marketing affiliate. In addition, Order 2004 restricts access to natural gas transmission customer data by marketing and other energy affiliates and provides certain conditions on service provided by interstate pipelines to their gas marketing and energy affiliates. We have implemented changes in business processes to comply with this order. In November 2006, the D.C. Circuit Court vacated Order 2004 as that order applies to interstate natural gas pipelines and remanded that proceeding to the FERC for further action.

On January 9, 2007, the FERC issued Order 690 in response to the D. C. Circuit Court's decision. In its Order, the Commission issued new interim standards of conduct pending the outcome of a new rulemaking proceeding. The interim standards will only govern the relationship between an interstate pipeline and its marketing affiliates as opposed to its energy affiliates, the latter being a much broader category as originally set forth in Order 2004. As a result, the Commission effectively "repromulgated" on a temporary basis the Standards of Conduct first issued in Order 497 in 1992, while it considers its course of action to address the court's decision on a more permanent basis.

On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking ("NOPR") in Docket No. RM07-1 wherein it proposes to make permanent its interim standards of conduct issued in Order 690. The Commission is also seeking comment as to whether it should make comparable changes to the electric industry standards of conduct that were not affected by either the November 2006 decision by the D.C. Circuit Court, or by Order 690, as well as comments regarding certain other electric-related exceptions to Order 2004. We continue to closely monitor these proceedings and administer our compliance programs accordingly.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and Congress, especially in light of market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce. In response to this issue, Congress, in the Energy Policy Act of 2005 ("EPACT"), and the FERC have implemented requirements to ensure that energy prices are not impacted by the exercise of market power or manipulative conduct. EPACT prohibits the use of any "manipulative or deceptive device or contrivance" in connection with the purchase or sale of natural gas, electric energy or transportation subject to the FERC's jurisdiction. The FERC then adopted the Market Manipulation Rules and the Market Behavior Rules to implement the authority granted under EPACT. These rules, which prohibit fraud and manipulation in wholesale energy markets, are very vague and are subject to broad interpretation. Although the FERC has not issued any order interpreting these rules, it is likely that the FERC will give itself broad latitude in determining whether specific behavior violates the rules. In addition, EPACT gave the FERC increased penalty authority for these violations. The FERC may now issue civil penalties of up to $1 million per day for each violation of FERC rules, and there are possible criminal penalties of up to $1 million and 5 years in prison. Given the FERC's broad mandate granted in EPACT, it is assumed that if energy prices are high, the FERC will investigate energy markets to determine if behavior unduly impacted or "manipulated" energy prices.

Intrastate Pipeline Regulation

Our intrastate liquids and natural gas pipeline operations generally are not subject to rate regulation by the FERC, but they are subject to regulation by various agencies of the states in which they are located. However, to the extent that our intrastate pipeline systems deliver natural gas into interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline making deliveries on behalf of a local distribution company or an interstate natural gas pipeline. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Natural Gas Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own certain natural gas pipelines that we believe meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but historically has not entailed rate regulation. In 2005, the FERC initiated an inquiry regarding the extent to which gathering (both offshore and onshore) systems, particularly those that have been previously transferred from a regulated entity should be regulated by the FERC. The inquiry is still open at this time. Further, some states have, or are considering, providing greater regulatory scrutiny over the commercial regulation of natural gas gathering business. Many of the producing states have previously adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities.

Sales of Natural Gas, Crude Oil, Condensate and Natural Gas Liquids

The price at which we sell natural gas currently is not subject to federal or state regulation except for certain systems in Texas. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations. Some of the FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different than other natural gas marketers with whom we compete.

Our sales of crude oil, condensate and natural gas liquids currently are not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the ICA. Certain regulations implemented by the FERC in recent years could increase the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other marketers of these products.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment for the passage of oil and natural gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

Tariffs and Rate Cases

Lakehead system

Under published tariffs at December 31, 2006 (including the tariff surcharges related to Lakehead system expansions) for transportation on the Lakehead system, the rates for transportation of heavy crude oil from Neche, North Dakota, where the System enters the United States (unless otherwise stated), to principal delivery points are set forth below.

	Published Tariff Per Barrel
To Clearbrook, Minnesota	$0.218
To Superior, Wisconsin	0.437
To Chicago, Illinois area	0.919
To Marysville, Michigan area	1.102
To Buffalo, New York area	1.129
Chicago to the international border near Marysville	0.395

The rates at December 31, 2006 for light and medium crude oils and NGL's are lower than the rates set forth in the table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. We periodically adjust our tariff rates as allowed under the FERC's indexing methodology and the tariff agreements described below.

Base Rates:

The base portion of the rates for the Lakehead system are subject to an annual escalation, which cannot exceed established ceiling rates as approved by the FERC, and determined in compliance with the FERC-approved indexing methodology.

SEP II Surcharge:

Under the Settlement Agreement with CAPP that the FERC approved in 1996 and reconfirmed in 1998, we implemented a tariff surcharge related to our SEP II project. This tariff surcharge, which is added to the base rates, is a cost-of-service based calculation that is trued-up annually (usually in April) for actual costs and throughputs from the previous calendar year, and is not subject to indexing. The initial term of the SEP II portion of the settlement agreement was for 15 years beginning in 1999.

Terrace Surcharge:

Under the Tariff Agreement approved by the FERC in 1998, we also implemented a tariff surcharge for the Terrace expansion program of approximately $0.013 per barrel for light crude oil from the Canadian border to Chicago. On April 1, 2001, pursuant to an agreement between us and Enbridge Pipelines, our share of the surcharge was increased to $0.026 per barrel. This surcharge was in effect until April 1, 2004, when our share of the surcharge changed to $0.007 per barrel. Our share will remain at this level until 2010, after which time the surcharge will return to $0.013 per barrel through 2013, the term of the agreement. In addition to the Terrace surcharge, included in the 2005 tariff is the Terrace Schedule C adjustment. Under the tariff agreement, when Terrace Phase III facilities are in service, and annual actual average pumping exiting Clearbrook are less than 225,000 M^3 per day, an adjustment is made to the Terrace surcharge. In 2006, this adjustment is $0.041 per barrel, based on annual actual average pumpings exiting Clearbrook of 165,300 M^3 per day in 2005.

Facilities Surcharge:

On July 1, 2004, the FERC approved a settlement with CAPP involving a Facilities Surcharge mechanism, which allows for the recovery of costs for enhancements or modifications to the system at shipper request and approved by CAPP. The Facilities Surcharge permits the Lakehead system to recover the costs associated with particular shipper-requested projects through an incremental surcharge layered on top of the existing base rates and other FERC-approved surcharges already in effect. Like the SEP II surcharge, the Facilities Surcharge is a cost-of-service-based tariff mechanism that is trued-up each year for actual costs and throughput and, therefore, is not subject to adjustment either upwards or downwards under indexing. In 2006, the Facilities Surcharge was $0.016 per barrel for light movements from the U.S./Canada border near Neche, North Dakota to Chicago. The Facilities Surcharge currently includes four projects that were agreed to with CAPP in 2004. Additional projects to be included in the Facilities Surcharge will be determined as the result of a negotiating process between management of the Lakehead system and CAPP.

On March 16, 2006, the FERC approved the Offer of Settlement filed by Enbridge on December 21, 2005, seeking approval for the Southern Access mainline expansion surcharge under the provisions of the previously approved Facilities Surcharge mechanism. The Southern Access mainline expansion centers on the construction of a new 42-inch diameter pipeline between Superior, Wisconsin and Flanagan, Illinois, along with associated upstream modifications to balance the expanded capacity created by the new Superior-to-Flanagan line.

On September 1, 2006, Enbridge filed an Offer of Settlement with the FERC seeking prompt approval for the Southern Access Extension surcharge. The proposed Extension is a new 36-inch pipeline which connects with the Southern Access Mainline Expansion pipeline at Flanagan to Patoka, Illinois, which allows Canadian producers and shippers to access the Patoka hub, where they can then access other refining centers. Under the framework that established the Facilities Surcharge already approved by the Commission, the proposed tolling methodology in the Offer of Settlement asked that the costs for the Extension be added to the existing base rates as a surcharge. A variety of benefits would accrue to shippers through the Extension, including a reduction in total tariff rates due to the higher utilization of upstream facilities and therefore reducing the net cost to shippers even if they do not ship on the Extension itself. The Offer of Settlement was opposed by three shippers and was rejected by the Commission on December 8, 2006, which stated that Enbridge did not submit adequate proof that the proposed pipeline would benefit all shippers. Enbridge still intends to continue with the development of the Extension and is exploring alternative tolling methodologies that would be supported by all shippers.

Mid-Continent system

The Mid-Continent system is comprised of pipeline, terminaling, and storage infrastructure located in the U.S. Mid-continent region. Specifically the system originates in Cushing, Payne County, Oklahoma and offers transportation service to Wood River, Madison County, Illinois; West Tulsa, Oklahoma, other Mid-Continent system facilities, local area refineries, and other interconnected pipe non-affiliated infrastructure. The rates for the transportation of light crude oil from Cushing, Payne County, Oklahoma to principle delivery points are set forth below:

	Published Tariff Per Barrel
To Wood River, Illinois	$0.440
To West Tulsa, Oklahoma	$0.185

The rates, at December 31, 2006 outlined above, apply to light crude only. Medium and heavy crude oil transportation rates on these systems are higher to compensate us for differences in the costs of shipping different types and grades of liquid hydrocarbons.

Where applicable, we periodically adjust our tariff rates as allowed under the FERC's indexing methodology. Currently, this methodology allows for an adjustment of rates equal to the PPI-FG +1.3%, which adjustment is made effective July 1 of each year.

North Dakota system

Our North Dakota system consists of both gathering and trunkline assets. All gathering rates from points in North Dakota, Montana and Wyoming are $0.608 per barrel, and rates for transportation of light crude oil to principle delivery points via trunklines on our North Dakota System are set forth below:

	Published Tariff Per Barrel
From Renville, Bottinaeu, Burke, Ward and Mountrail Counties to Clearbrook, Minnesota	$0.740
From Sheridan and Williams County to Clearbrook, Minnesota	$0.847
From Sheridan County to Clearbrook, Minnesota	$0.871
From Sheridan County to Clearbrook, Minnesota	$0.906
From Ramberg/Beaver Lodge Station, North Dakota to Clearbrook, Minnesota	$0.763
From Williams County to Clearbrook, Minnesota	$0.967
From McKenzie County to Clearbrook, Minnesota	$1.002

The rates at December 31, 2006, outlined above, are subject to adjustment as allowed under the indexing methodology established by the FERC. Currently this methodology allows for an adjustment of rates equal to the PPI-FG +1.3%, which is made effective July 1 of each year.

North Dakota Expansion

Due to significant increases in crude oil production in the Williston Basin area of North Dakota and Montana, our North Dakota system has been under significant capacity apportionment during the past year. As a result, we submitted an Offer of Settlement to the FERC on August 14, 2006 to facilitate a two-stage expansion of our North Dakota system. Our Offer of Settlement has received wide support from current shippers on our North Dakota system. The settlement encompasses the expansion of our North Dakota system mainline between Minot, North Dakota and Clearbrook, Minnesota and the feeder line between Alexander and Beaver Lodge, North Dakota. The recovery mechanism is the implementation of two agreed-upon surcharges to be added to the existing base rates of our North Dakota system for a period of five years. The proposed surcharges are transparent, cost of service based tariff mechanisms that will be trued-up annually to reflect actual costs and throughput and will not be subject to index adjustments.

The expansion of our North Dakota system is expected to add approximately 30,000 Bpd of incremental capacity to the mainline, increasing the existing capacity to approximately 110,000 Bpd between Minot, North Dakota and Clearbrook, Minnesota. The expansion is also expected to add approximately 30,000 Bpd of incremental capacity to the feeder segment of the system, increasing the existing capacity to approximately 90,000 barrels per day, between Alexander and Beaver Lodge. We expect the total cost of completing the mainline and feeder expansions of the North Dakota systems to approximate $70 million.

On October 31, 2006, the FERC approved the methodology of the proposed cost-based recovery mechanism outlined in the North Dakota Offer of Settlement on the grounds that it appears fair, reasonable and in the public interest.

Natural Gas Systems

Tariff rates on the FERC-regulated natural gas pipelines are approved by the FERC and vary by pipeline depending on a number of factors, including cost of providing service, throughput levels on the pipeline, and other factors. Competitive forces may prompt us to charge tariff rates below the FERC-approved maximum rate on our interstate systems. The rates charged for transmission of natural gas on pipelines not regulated by the FERC, or a state agency, are established by competitive forces.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines and storage and processing facilities are subject to extensive federal and state environmental, operational and safety regulation. The added costs imposed by regulations are generally no different than those imposed on our competitors. The failure to comply with such rules and regulations can result in substantial penalties and/or enforcement actions and added operational costs.

Pipeline Safety and Transportation Regulation

Our transmission and non-rural gathering pipelines are subject to regulation by the United States Department of Transportation, or DOT, Pipeline and Hazardous Materials Safety Administration ("PHMSA") under Title 49 United States Code (Pipeline Safety Act, or PSA) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. The PHMSA is the agency charged with regulating the safe transportation of hazardous materials under all modes of transportation, including intrastate pipelines. Periodically the PSA has been reauthorized and amended, imposing new mandates on the regulator to promulgate new regulations, imposing direct mandates on operators of pipelines.

On December 17, 2002 the PSI Act of 2002 was enacted reauthorizing and amending the PSA. The most significant amendment required natural gas pipelines to develop integrity management programs and conduct integrity assessment tests at a minimum of seven year intervals. Such tests can include internal inspection, hydrostatic pressure tests or direct assessments on pipelines in certain high consequence areas. The PHMSA has since promulgated rules for this and other mandates included in the PSI of 2002.

On December 29, 2006 the "Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006" (PIPES of 2006) was signed into legislation that further amended the Pipeline Safety Act. Many of the provisions were welcome, including strengthening excavation damage prevention and enforcement. The most significant provisions of PIPES of 2006 that will affect the Partnership, but not materially, include a mandate to PHMSA to remove most exemptions from federal regulations for liquid pipelines operating at low stress and mandates PHMSA to undertake rulemaking requiring pipeline operators to have a human factors management plan for pipeline control room personnel, including consideration for controlling hours of service.

We have incorporated the new requirements of the 2002 and 2006 PSA amendments into procedures and budgets and, while we expect to incur higher regulatory compliance costs, the increase is not expected to be material.

In September 2006, PHMSA proposed extending its regulatory oversight to include environmentally sensitive areas that are beyond the scope of its current jurisdiction. PHMSA currently has jurisdiction over rural gathering pipelines, low operating stress transmission pipelines that are located in high consequence areas and pipelines in urban areas or across navigable waters. We expect this proposed rule to become final by mid-2007 and do not expect the new mandates to have a material impact on our current systems. However, the PIPES of 2006 mandated that PHMSA go further and expand jurisdiction over all low stress pipelines, not just those in high consequence areas. We expect the PHMSA, therefore, to immediately issue another proposed rule for low stress pipelines, but until such rules are proposed, we are not certain of the effect or costs that the new requirements may have on our operations.

When hydrocarbons are released into the environment, the PHMSA can impose a return-to-service plan, which can include implementing certain internal inspections, pipeline pressure reductions, and other strategies to verify the integrity of the pipeline in the affected area. We do not anticipate any return-to-service plans that will have a material impact on system throughput or compliance costs; however we have the potential of incurring additional expenditures to remediate any condition in the event of a discharge or failure on the system.

Our trucking and railcar operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous and other materials.

We believe that our pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, we have taken actions to remediate the situations. Nevertheless, significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

Environmental Regulation

General. Our operations are subject to complex federal, state, and local laws and regulations relating to the protection of health and the environment, including laws and regulations which govern the handling, storage and release of crude oil and other liquid hydrocarbon materials or emissions from natural gas compression facilities. As with the pipeline and processing industry in general, complying with current and anticipated environmental laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position since the operations of our competitors are generally similarly affected.

In addition to compliance costs, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with our operations, such as leaks or spills of crude oil, liquids or natural gas or other substances from our pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines, penalties, or damages for related violations of environmental laws or regulations.

Although we are entitled, in certain circumstances, to indemnification from third parties for environmental liabilities relating to assets we acquired from those parties, these contractual indemnification rights are limited and, accordingly, we may be required to bear substantial environmental expenses. However, we believe that through our due diligence process, we identify and manage substantial issues.

Air and Water Emissions. Our operations are subject to the federal Clean Air Act and the federal Clean Water Act and comparable state and local statutes. We anticipate, therefore, that we will incur certain capital expenses in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities.

The Oil Pollution Act (OPA) was enacted in 1990 and amends parts of the CWA and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements for many of our non-pipeline facilities, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. For our liquid pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For our non-transportation facilities, such as storage tanks that are not integral to pipeline transportation system, the OPA regulations are promulgated by the EPA. We believe we are in material compliance with these laws and regulations.

Hazardous Substances and Waste Management. The federal CERCLA (also known as the "Superfund" law), and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites and companies that disposed or arranged for disposal of hazardous substances found at such sites. We may generate some wastes that fall within the definition of a "hazardous substance." We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such wastes have been disposed. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for material cleanup costs under CERCLA or similar state laws.

Employee Health and Safety. The workplaces associated with our operations are subject to the requirements of the federal OSHA and comparable state statutes that regulate worker health and safety. We have an ongoing safety, procedure and training program for our employees and believe that our operations are in compliance with applicable occupational health and safety requirements, including industry consensus standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

Site Remediation. We own and operate a number of pipelines, gathering systems, storage facilities and processing facilities that have been used to transport, distribute, store and process crude oil, natural gas and other petroleum products. Many of our facilities were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under our control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from our properties may be subject to CERCLA, RCRA and analogous state laws as described above.

Under these laws, we could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, Enbridge Management, as the entity with managerial responsibility for us, could also be liable for such costs to the extent that we are unable to fulfill our obligations. We have conducted site investigations at some of our facilities to assess historical environmental issues, and we are currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable government agencies where appropriate.

In connection with our acquisition of the Midcoast system from Enbridge, the General Partner agreed to indemnify us and other related persons for certain environmental liabilities of which the General Partner had knowledge. Pursuant to the contribution agreement related to this acquisition, the General Partner will not be required to indemnify us until the aggregate liabilities, including environmental liabilities, exceed $20.0 million, and the General Partner's aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, $150.0 million. We will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed under the contribution agreement between the General Partner and us. In addition, we will be liable for all removal, remediation and disposal of all asbestos containing materials and all naturally occurring radioactive materials associated with the Northeast Texas system and for which the General Partner is liable to the prior owner of that system.

Although we believe these indemnities and conditions provide valuable protection, it is possible that the sellers from whom these assets were purchased will not be able to satisfy their indemnity obligations or their remedial obligations related to retained liabilities or properties. In this case, it is possible that governmental agencies or third party claimants could assert that we may be liable or bear some responsibility for such obligations.

EMPLOYEES

Neither we nor Enbridge Management, have any employees. Our general partner has delegated to Enbridge Management, pursuant to a delegation of control agreement, substantially all of the responsibility for our day-to-day management and operation. Our general partner, however, retains certain functions and approval rights over our operations. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel, who act on Enbridge Management's behalf as its agents. We are ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

Our operations are subject to many hazards inherent in the liquid petroleum and natural gas gathering, treating, processing and transportation industry. We maintain insurance coverage for our operations and properties considered to be customary in the industry. Our coverage limits for property and business interruption, general liability, and polution liability insurance are expressed in Canadian dollars, or CAD, and vary from CAD $400 million to CAD $650 million, or US $343 to $558 million, for property and business interruption, general liability, and pollution liability insurance. The exchange rate of $0.8581 United States dollars, or USD, for each CAD represents the effective exchange rate at December 31, 2006. Insurance policy deductibles vary with coverage and as expressed in USD range from approximately $9 million, $0.1 million, and $2.2 million for property, general liability, and pollution liability, respectively. We can make no assurance, however, that the insurance coverage we maintain will be available or adequate for any particular risk or loss, or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations and cash flows.

TAXATION

For U.S. federal income tax purposes, we are not a taxable entity. Generally, federal and state income taxes on our taxable income are borne by our individual partners through the allocation of our taxable income. Such taxable income may vary substantially from net income reported in our consolidated statements of income.

AVAILABLE INFORMATION

We file annual, quarterly and other reports, and any amendments to those reports, and information with the SEC under the Exchange Act. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including ours.

We also make available free of charge on or through our Internet website *http://www.enbridgepartners.com* our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not part of this report.

Item 1A. Risk Factors

We encourage you to read the risk factors below in connection with the other sections of this Annual Report on Form 10-K.

RISKS RELATED TO OUR BUSINESS

Our financial performance could be adversely affected if our pipeline systems are used less.

Our financial performance depends to a large extent on the volumes transported on our pipeline systems. Decreases in the volumes transported by our systems, whether caused by supply or demand factors in the markets these systems serve, competition or otherwise, can directly and adversely affect our revenues and results of operations.

The volume of shipments on our Lakehead system depends heavily on the supplies of western Canadian crude oil. Insufficient supplies of western Canadian crude oil will adversely affect our business by limiting shipments on our Lakehead system. Decreases in conventional crude oil exploration and production activities in western Canada and other factors including supply disruption and competition can reduce the utilization of our Lakehead system. For example, in January 2005, deliveries on our Lakehead system were impacted by a fire at a Suncor facility. The volume of crude oil that we transport on the Lakehead system also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the delivery by others of crude oil and refined products into these regions and the Province of Ontario. Pipeline capacity for the delivery of crude oil to the Great Lakes and Midwest regions of the United States currently exceeds refining capacity.

In addition, our ability to increase deliveries to expand the Lakehead system in the future depends on increased supplies of western Canadian crude oil. We expect that growth in future supplies of western Canadian crude oil will come from oil sands projects in Alberta, Canada. Furthermore, full utilization of additional capacity as a result of our current and future expansions of the Lakehead system, including the

Terrace expansion program, will largely depend on these anticipated increases in crude oil production from oil sands projects.

The volume of shipments on natural gas systems depends on the supply of natural gas and NGLs available for shipment on those systems from the producing regions that supply these systems. Volumes shipped on these systems also are affected by the demand for natural gas and NGLs in the markets these systems serve. Existing customers may not extend their contracts if the availability of natural gas from the Mid-continent, Gulf Coast and East Texas producing regions was to decline or if the cost of transporting natural gas from other producing regions through other pipelines into the markets served by the natural gas systems was to render the delivered cost of natural gas on our systems uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Changes in our tariff rates or challenges to our tariff rates could have a material adverse effect on our financial condition and results of operations; a recent FERC Policy Statement that limited allowances for income tax in an unrelated pipeline's cost of service, if applied to our FERC-regulated systems, could adversely affect our rates.

The tariff rates charged by several of our existing pipeline systems are regulated by the FERC, or various state regulatory agencies. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, the profitability of our pipeline businesses might suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which delay could further reduce our cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically propose and implement new rules and regulations, terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the tariff rates charged for our services. Some producing states, including Oklahoma and Texas, are considering legislation that would require rate and/or service regulation of gathering and intrastate transmission natural gas systems. Increased state regulation could adversely impact our natural gas systems.

The question of whether and to what extent an income tax allowance should be included in a regulated utility's cost of service for rate-making purposes was a matter of uncertainty for a number of years. In a 1995 decision involving our Lakehead system, which we refer to as the *Lakehead ruling*, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. A subsequent appeal of the *Lakehead ruling* was resolved by settlement and therefore was not adjudicated. In another FERC proceeding involving SFPP, the FERC initially relied on its previous *Lakehead ruling* to hold that SFPP could not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding appealed the FERC's orders to the United States Court of Appeals for the District of Columbia Circuit. On July 20, 2004, in *BP West Coast Products LLC v. FERC*, which we refer to as the *BP West Coast decision*, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding certain aspects of the FERC's orders regarding the SFPP case, but vacating the FERC's ruling regarding the proper tax allowance for SFPP. The United States Court of Appeals for the District of Columbia rejected the FERC's rationale for its *Lakehead ruling* and remanded the case to the FERC for further proceedings.

In the wake of the *BP West Coast* decision, the FERC initiated a notice and comment process to address tax allowance issues across a range of industries. We and many other companies commented on the proceeding. On May 4, 2005, the FERC issued a policy statement on income tax allowances, in which it reinstated its earlier policy of providing a full tax allowance on all partnership and similar legal interests in regulated companies if the owner of that interest has an actual or potential tax liability on the income earned through that interest. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. On December 16, 2005, FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16 order have been appealed to the D.C. Circuit Court, and rehearing requests have been filed with respect to the December 16 order. As well as the SFPP decision, which is currently on appeal, there are two other cases with respect to tax allowance pending in the D.C. Circuit Court including Exxon Mobil Oil Corporation v. FERC and CAPP v. FERC.

The D.C. Circuit Court heard oral arguments on these cases on December 12, 2006. A decision is expected by April 2007. At this time, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. Whether the income tax allowance policy is ultimately upheld or modified on judicial review, could affect the tariffs of FERC-regulated pipelines.

A related issue is whether the FERC's income tax allowance policy can be relied upon by shippers as a substantial change in circumstances sufficient to remove the grandfathering protection under the EP Act from an oil pipeline's rates. The FERC determined in the SFPP case that its policy statement on income tax allowances does not represent a change from its pre-EP Act policy and therefore, cannot affect grandfathering of rates, a position that is still potentially subject to further judicial review.

At this time, the effect of the FERC's policy statement on income tax allowances on us is uncertain. The tariff rates on our common carrier interstate liquids pipelines have been established under a variety of different circumstances including settlements and tariff indexing. It is anticipated that a change in the income tax allowance policy would only impact those rates that were established after indexing. Even with the indexed rates, the income tax allowance is only one of many elements supporting our pipeline rates for service. Accordingly, we cannot predict with certainty what rates we will be allowed to charge in the future, or the potential impact on us of a change in the FERC's policy statement on income tax allowances.

We believe that the rates we charge for transportation services on our interstate common carrier liquids pipelines are just and reasonable under the ICA. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Competition may reduce our revenues.

Our Lakehead system faces current, and potentially further competition for transporting western Canadian crude oil from other pipelines, which may reduce our revenues. Our Lakehead system competes with other crude oil and refined product pipelines and other methods of delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Minnesota; Chicago, Illinois; Detroit, Michigan; Toledo, Ohio; Buffalo, New York; and Sarnia, Ontario and the refinery market and pipeline hub located in the Patoka/Wood River area of southern Illinois. Refineries in the markets served by our Lakehead system compete with refineries in western Canada, the Province of Ontario and the Rocky Mountain region of the United States for supplies of western Canadian crude oil.

Our Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

We also encounter competition in our natural gas gathering, treating, processing and transmission businesses. A number of new interstate natural gas transmission pipelines being constructed could reduce the revenue we derive from the interstate and intrastate transmission of natural gas. Many of the large wholesale customers served by our systems' transmission and wholesale customer pipelines have multiple pipelines connected or adjacent to their facilities. Thus, many of these wholesale customers have the ability to purchase natural gas directly from a number of pipelines and/or from third parties that may hold capacity on other pipelines. Likewise, most natural gas producers and owners have alternate gathering and processing facilities available to them. In addition, they have other alternatives, such as building their own gathering facilities or, in some cases, selling their natural gas supplies without processing. Some of our natural gas marketing competitors have greater financial resources and access to larger supplies of natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do.

Our gas marketing operations involve market and certain regulatory risks.

As part of our natural gas marketing activities, we purchase natural gas at prices determined by prevailing market conditions. Following our purchase of natural gas, we generally resell natural gas at a higher price under a sales contract that is generally comparable in terms to our purchase contract, including any price escalation provisions. The profitability of our natural gas operations may be affected by the following factors:

- our ability to negotiate on a timely basis natural gas purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers' willingness to use other fuels when natural gas prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results;
- the ability of our customers to make timely payment;
- inability to match purchase and sale of natural gas on comparable terms; and
- changes in, limitations upon, or elimination of the regulatory authorization required for our wholesale sales of natural gas in interstate commerce.

Our results may be adversely affected by commodity price volatility and risks associated with our hedging activities.

We buy and sell natural gas and NGLs in connection with our marketing activities. Commodity price exposure is also inherent in gas purchase and resale activities and in gas processing. To the extent that we engage in hedging activities to reduce our commodity price exposure, we may be prevented from realizing the full benefits of price increases above the level of the hedges. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under such contracts. In addition certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earnings volatility due to turbulent commodity prices.

Compliance with environmental and operational safety regulations, including any remediation of soil or water pollution or hydrostatic testing of our pipeline systems, may increase our costs and/or reduce our revenues.

Our pipeline, gathering, processing and trucking operations are subject to federal, state and local laws and regulations relating to environmental protection and operational and worker safety. Liquid petroleum and natural gas transportation and processing operations always involve the risk of costs or liabilities or operational modifications related to regulatory compliance as well as resulting from historical environmental contamination, accidental releases or upsets, regulatory enforcement, litigation or safety and health incidents. As a result, we may incur costs or liabilities of this type, or experience a reduction in revenues, in the future. We may also incur costs in the future due to changes in environmental and safety laws and regulations, enforcement policies or claims for personal, property or environmental damage. We may not be able to recover these costs from insurance or through higher tariffs.

Failure of pipeline operations due to unforeseen interruptions or catastrophic events may adversely affect our business and financial condition.

Operation of complex pipeline systems, gathering, treating, processing and trucking operations involves many risks, hazards and uncertainties, such as operational hazards and unforeseen interruptions caused by events beyond our control. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. A casualty occurrence might result in injury or loss of life or extensive property or environmental damage for which we may bear a part or all of the cost.

Our acquisition strategy may be unsuccessful if we incorrectly predict operating results, are unable to identify and complete future acquisitions and integrate acquired assets or businesses or are unable to raise financing on acceptable terms.

The acquisition of complementary energy delivery assets is a component of our strategy. Acquisitions present various risks and challenges, including:

- the risk of incorrect assumptions regarding the future results of the acquired operations or expected cost reductions or other synergies expected to be realized as a result of acquiring such operations;
- the risk of failing to effectively integrate the operations or management of acquired assets or businesses or a significant delay in such integration; and
- diversion of management's attention from existing operations.

In addition, we may be unable to identify acquisition targets and consummate acquisitions in the future or be unable to raise, on terms we find acceptable, any debt or equity financing that may be required for any such acquisition.

Our actual construction and development costs could exceed our forecast and our cash flow from construction and development projects may not be immediate which may limit our ability to increase cash distributions.

Our strategy contemplates significant expenditures for the development, construction or other acquisitions of energy infrastructure assets. Increased demand for the steel used to fabricate the pipe needed for our construction projects and increased competition for labor has resulted in increased costs for these resources. As a result, we may not be able to complete our projects at the costs currently estimated or within the time periods we have projected. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional equity.

Any or all of these methods may not be available when needed or may adversely affect our future results operations and cash flows.

Our revenues and cash flows may not increase immediately on our expenditure of funds on a particular project. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers begin using the systems. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays, or other factors, we may not meet our obligations as they become due and we may need to reduce or reprioritize our capital budget, sell non-strategic assets, access the capital markets or reassess our level of distributions to unitholders to meet our capital requirements.

Measurement losses on our pipeline system can be materially impacted by changes in estimation, commodity prices and other factors.

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

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

Quantifying oil measurement losses is inherently difficult because physical measurements of volumes are not practical due to the fact that products constantly move through our pipelines and virtually all of our pipeline systems are located underground. In our case, measuring and quantifying oil measurement losses is especially difficult because of the size and scope of our pipeline systems and the number of different grades of crude oil and types of crude oil products we carry. Accordingly, we utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including: 1) the significant quantities (i.e., thousands) of measurement meters that we use throughout our natural gas systems, primarily around our gathering and processing assets; 2) varying qualities of natural gas in the streams gathered and processed through our systems; and 3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement losses that can occur on our natural gas systems.

The interests of Enbridge may differ from our interests and the interests of our security holders, and the board of directors of Enbridge Management may consider the interests of all parties to a conflict, not just the interests of our security holders, in making important business decisions.

Enbridge indirectly owns all of the stock of our general partner and all of the voting stock of Enbridge Management, and elects all of the directors of both companies. Furthermore, some of the directors and officers of our general partners and Enbridge Management are also directors and officers of Enbridge. Consequently, conflicts of interest could arise between our unitholders and Enbridge.

Our partnership agreement limits the fiduciary duties of our general partner to our unitholders. These restrictions allow our general partner to resolve conflicts of interest by considering the interests of all of the parties to the conflict, including Enbridge Management's interests, our interests and those of our general partner. In addition, these limitations reduce the rights of our unitholders under our partnership agreement to sue our general partner or Enbridge Management, its delegee, should its directors or officers act in a way that, were it not for these limitations of liability, would constitute breaches of their fiduciary duties.

We do not have any employees. In managing our business and affairs, we will rely on employees of Enbridge, and its affiliates, who will act on behalf of and as agents for us. A decrease in the availability of employees from Enbridge could adversely affect us.

We are exposed to credit risks of our customers

For example our Bamagas system has agreements to provide transportation of up to 276,000 MMBtu/d of natural gas for a remaining period of 17 years to two utility plants that are indirectly owned by Calpine Corporation ("Calpine"). The Bamagas system receives a fixed demand charge of $0.07 per MMBtu of natural gas for 200,000 MMBtu/d, regardless of whether the capacity is used. In December 2005, Calpine and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. In connection with the bankruptcy filing, Calpine has announced receipt of commitments for up to $2 billion of Debtor in Possession, or DIP financing to allow for the continued operation of its power plants. Our Bamagas system is the sole supplier of natural gas to these two utility plants, and we expect the subsidiary that owns these utility plants to continue performing under the terms of our agreement. Although we fully expect our customer to continue to meet its obligations to us under the terms of the transportation agreements, we are exposed to a potential asset impairment of up to $53 million, representing the book value of the pipeline, if the customer is unable to fulfill its commitments. In April 2006, Calpine announced its intent to sell approximately 20 of its non-core and non-strategic power plants, although the plants to be sold have not been announced. Calpine has continued to perform under the terms of its agreement with Bamagas and we remain confident that any losses we may incur with respect to Calpine's bankruptcy will be minimal. We continue to monitor the Calpine bankruptcy proceedings and will recognize any losses that may result when it becomes evident that a loss has been incurred.

Canada's ratification of the Kyoto Protocol may adversely impact our operations.

In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. We and Enbridge are monitoring the Canadian federal government's approach to implementation. While the United States is not a signatory to the Kyoto Protocol, other environmental protection initiatives have been implemented regulating certain priority pollutants. Revisions have been proposed to the U.S. Energy Act that would, if passed, expand the regulation of certain greenhouse gas emissions requiring a cap and establishing a trade to facilitate compliance. Such provisions would make natural gas pipelines the segment of the gas industry regulated by an amendment. While proposed legislation has not yet passed and as other legislation is being proposed the outcome is uncertain at this time. If and when these provisions pass the Partnership could be subject to additional costs to monitor and control emissions above and beyond current practices and permits.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE AND RELATIONSHIPS WITH OUR GENERAL PARTNER AND ENBRIDGE MANAGEMENT

Our partnership agreement and the delegation of control agreement limit the fiduciary duties that Enbridge Management and our general partner owe to our unitholders and restrict the remedies available to our unitholders for actions taken by Enbridge Management and our general partner that might otherwise constitute a breach of a fiduciary duty.

Our partnership agreement contains provisions that modify the fiduciary duties that our general partner would otherwise owe to our unitholders under state fiduciary duty law. Through the delegation of control agreement, these modified fiduciary duties also apply to Enbridge Management as the delegate of our general partner. For example, our partnership agreement:

- permits our general partner to make a number of decisions, including the determination of which factors it will consider in resolving conflicts of interest, in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;
- provides that any standard of care and duty imposed on our general partner will be modified, waived or limited as required to permit our general partner to act under our partnership agreement and to make any decision pursuant to the authority prescribed in our partnership agreement, so long as such action is reasonably believed by the general partner to be in our best interests; and
- provides that our general partner and its directors and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions if they acted in good faith.

These and similar provisions in our partnership agreement may restrict the remedies available to our unitholders for actions taken by Enbridge Management or our general partner that might otherwise constitute a breach of a fiduciary duty.

Potential conflicts of interest may arise among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Because the fiduciary duties of the directors of our general partner and Enbridge Management have been modified, the directors may be permitted to make decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders.

Conflicts of interest may arise from time to time among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Conflicts of interest may also arise from time to time between us and our unitholders, on the one hand, and Enbridge Management and its shareholders, on the other hand. In managing and controlling us as the delegate of our general partner, Enbridge Management may consider the interests of all parties to a conflict and may resolve those conflicts by making decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders. The following decisions, among others, could involve conflicts of interest:

- whether we or Enbridge will pursue certain acquisitions or other business opportunities;
- whether we will issue additional units or other equity securities or whether we will purchase outstanding units;
- whether Enbridge Management will issue additional shares;
- the amount of payments to Enbridge and its affiliates for any services rendered for our benefit;

- the amount of costs that are reimbursable to Enbridge Management or Enbridge and its affiliates by us;
- the enforcement of obligations owed to us by Enbridge Management, our general partner or Enbridge, including obligations regarding competition between Enbridge and us; and
- the retention of separate counsel, accountants or others to perform services for us and Enbridge Management.

In these and similar situations, any decision by Enbridge Management may benefit one group more than another, and in making such decisions, Enbridge Management may consider the interests of all groups, as well as other factors, in deciding whether to take a particular course of action.

In other situations, Enbridge may take certain actions, including engaging in businesses that compete with us, that are adverse to us and our unitholders. For example, although Enbridge and its subsidiaries are generally restricted from engaging in any business that is in direct material competition with our businesses, that restriction is subject to the following significant exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of our initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which we provided transportation at the time of our initial public offering;
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge's reasonable judgment, is not attributable to the competitive business; and
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us if that business is first offered for acquisition to us and the board of directors of Enbridge Management and our unitholders determine not to pursue the acquisition.

Since we were not engaged in any aspect of the natural gas business at the time of our initial public offering, Enbridge and its subsidiaries are not restricted from competing with us in any aspect of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as our Lakehead system, even if such transportation is in direct material competition with our business.

These exceptions also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia, Ontario to Montreal, Quebec. As a result of this reversal, Enbridge competes with us to supply crude oil to the Ontario, Canada market.

We can issue additional common or other classes of units, including additional i-units to Enbridge Management when it issues additional shares, which would dilute your ownership interest.

The issuance of additional common or other classes of units by us, including the issuance of additional i-units to Enbridge Management when it issues additional shares and the issuance of additional Class C units, other than our quarterly distributions to you, may have the following effects:

- the amount available for distributions on each unit may decrease;
- the relative voting power of each previously outstanding unit may decrease; and
- the market price of the Class A common units may decline.

Additionally, the public sale by our general partner of a significant portion of the Class B common units or Class C units that it currently owns could reduce the market price of the Class A common units. Our partnership agreement allows the general partner to cause us to register for public sale any units held by the general partner or its affiliates. A public or private sale of the Class B common units or Class C units currently held by our general partner could absorb some of the trading market demand for the outstanding Class A common units.

We are a holding company and depend entirely on our operating subsidiaries' distributions to service our debt obligations.

We are a holding company with no material operations. If we cannot receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations. Our operating subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions, which could further limit each operating subsidiary's ability to make distributions to us.

The debt securities we issue and any guarantees issued by the Subsidiary Guarantors will be structurally subordinated to the claims of the creditors of any of our operating subsidiaries who are not guarantors of the debt securities. Holders of the debt securities will not be creditors of our operating subsidiaries who have not guaranteed the debt securities. The claims to the assets of these non-guarantor operating subsidiaries derive from our own ownership interest in those operating subsidiaries. Claims of our non-guarantor operating subsidiaries' creditors will generally have priority as to the assets of such operating subsidiaries over our own ownership interest claims and will therefore have priority over the holders of our debt, including the debt securities. Our non-guarantor operating subsidiaries' creditors may include:

- general creditors;
- trade creditors;
- secured creditors;
- taxing authorities; and
- creditors holding guarantees.

Enbridge Management's discretion in establishing our cash reserves gives it the ability to reduce the amount of cash available for distribution to our unitholders.

Enbridge Management may establish cash reserves for us that in its reasonable discretion are necessary to fund our future operating and capital expenditures, provide for the proper conduct of business, and comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to our holders of common units.

RISKS RELATED TO OUR DEBT AND OUR ABILITY TO DISTRIBUTE CASH

Agreements relating to our debt restrict our ability to make distributions, which could adversely affect the value of our Class A Common Units, and our ability to incur additional debt and otherwise maintain financial and operating flexibility.

Our primary operating subsidiary is prohibited by its First Mortgage Notes from making distributions to us, and we are prohibited by our credit facility from making distributions to our unitholders, if a default exists under the respective governing agreements. In addition, the agreements governing our credit facility and our subsidiary's First Mortgage Notes may prevent us from engaging in transactions or capitalizing on business opportunities that we believe could be beneficial to us by requiring us to comply with various covenants, including the maintenance of certain financial ratios and restrictions on:

- incurring additional debt;
- entering into mergers or consolidations or sales of assets; and
- granting liens.

Although the indentures governing our senior notes do not limit our ability to incur additional debt, they impose restrictions on our ability to enter into mergers or consolidations and sales of assets and to incur liens to secure debt. A breach of any restriction under our credit facility or our indentures or our subsidiary's First Mortgage Notes could permit the holders of the related debt to declare all amounts outstanding under those agreements immediately due and payable and, in the case of the credit facility, terminate all commitments to extend further credit. Any subsequent refinancing of our current debt or any new indebtedness incurred by us or our subsidiaries could have similar or greater restrictions.

TAX RISKS TO COMMON UNITHOLDERS

We may be classified as an association taxable as a corporation rather than as a partnership, which would substantially reduce the value of our Class A common units.

We could be treated as a corporation for United States income tax purposes. Our treatment as a corporation would substantially reduce the cash distributions on the common units that we distribute quarterly. Moreover, treatment of us as a corporation could materially and adversely affect our ability to make payments on our debt securities. The anticipated benefit of an investment in our common units depends largely on the treatment of us as a partnership for federal income tax purposes. Under current law, we are treated as a partnership for federal income tax purposes and do not pay any federal income tax at the entity level. In order to qualify for this treatment, we must derive more than 90% of our annual gross income from specified investments and activities. While we believe that we currently do qualify and intend to meet this income requirement, we may not find it possible, regardless of our efforts, to meet this income requirement or may inadvertently fail to meet this income requirement. Current law may change so as to cause us to be treated as a corporation for federal income tax purposes without regard to our sources of income or otherwise subject us to entity-level taxation. If we were to be treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would pay state income taxes at varying rates. Under current law, distributions to unitholders would generally be taxed as a corporate distribution. Because a tax would be imposed upon us as a corporation, the cash available for distribution to a unitholder would be substantially reduced. Treatment of us as a corporation would cause a substantial reduction in the value of our units.

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. State tax legislation resulting in the imposition of a partnership-level income tax on us would reduce the cash distributions on the common units and the value of the i-units that we will distribute quarterly to Enbridge Management. The enactment of significant legislation imposing partnership-level income taxes could cause a reduction in the value of our units.

If the Internal Revenue Service does not respect our curative tax allocations, the after-tax return to our unitholders on their investment in our Class A common units would be adversely affected.

Our partnership agreement allows curative allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and book basis of our assets existing at the time of issuance of any Class A common units. If the Internal

Revenue Service, which we refer to as the IRS, does not respect our curative allocations, ratios of taxable income to cash distributions received by the holders of Class A common units will be materially higher than previously estimated

The tax liability of our unitholders could exceed their distributions or proceeds from sales of Class A common units.

The holders of our Class A common units will be required to pay United States federal income tax and, in some cases, state and local income taxes on their allocable share of our income, even if they do not receive cash distributions from us. They will not necessarily receive cash distributions equal to the tax on their allocable share of our taxable income. Further, if we have a large amount of nonrecourse liabilities, they may incur a tax liability that is greater than the money they receive when they sell their Class A common units.

A unitholder may be required to file tax returns with and pay income taxes to the states where we or our subsidiaries own property and conduct business.

In some cases, a unitholder may be required to file income tax returns with and pay income taxes to the states in which we or our subsidiaries own property and conduct business, which are currently Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, South Carolina, North Carolina, North Dakota, Oklahoma, Tennessee, Texas and Wisconsin. In the future, we may acquire property or do business in other states or in foreign jurisdictions. In addition to tax liabilities to such state and foreign jurisdictions, the owner of a Class A common unit may also incur tax and filing responsibilities to localities within such jurisdictions.

Ownership of Class A common units raises issues for tax-exempt entities and other investors.

An investment in our Class A common units by tax-exempt entities, including employee benefit plans, individual retirement accounts, Keogh plans and other retirement plans, regulated investment companies and foreign persons raises issues unique to them. Virtually all of the income derived from our Class A common units by a tax-exempt entity will be "unrelated business taxable income" and will be taxable to the tax-exempt entity. Further, a unitholder who is a nonresident alien, a foreign corporation or other foreign person will be required to file a federal income tax return and pay tax on his share of our taxable income because he will be regarded as being engaged in a trade or business in the United States as a result of his ownership of a Class A common unit.

Our registration with the Secretary of the Treasury as a "tax shelter" may increase your risk of an IRS audit.

Because we are a registered "tax shelter" with the Secretary of the Treasury, a unitholder may face an increased risk of an IRS audit resulting in taxes payable on our income as well as income not related to us. We could be audited by the IRS and adjustments to our income or losses could be made. Any unitholder owning less than a 1% profit interest in us has very limited rights to participate in the income tax and audit process. Further, any adjustments in our tax returns will lead to adjustments in the unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. Each unitholder is responsible for any tax owed as the result of an examination of their personal tax return.

Our treatment of a purchaser of Class A common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of the Class A common units.

Because we cannot match transferors and transferees of Class A common units, we are required to maintain the uniformity of the economic and tax characteristics of these units in the hands of the purchasers and sellers of these units. We do so by adopting certain depreciation conventions that do not conform to all aspects of the United States Treasury regulations. An IRS challenge to these conventions could adversely affect the tax benefits to a unitholder of ownership of the Class A common units and could have a negative impact on their value.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties and maps depicting the locations of our liquids and natural gas systems are included in Item 1. Business, which is incorporated herein by reference.

In general, our systems are located on land owned by others and are operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities. The pumping stations, tanks, terminals and certain other facilities of our systems are located on land that is owned by us, except for five pumping stations that are situated on land owned by others and used by us under easements or permits.

Substantially all of our Lakehead system assets are subject to a first mortgage lien collateralizing indebtedness of our Lakehead Partnership.

Titles to our properties acquired in the Midcoast system acquisition are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2006.

PART II

Item 5. Market for Registrant's Common Equity and Related Unitholder Matters

Our Class A common units are listed and traded on the NYSE, the principal market for the Class A common units, under the symbol "EEP." The quarterly price ranges per Class A common unit and cash distributions paid per unit for 2006 and 2005 are summarized as follows:

	First	Second	Third	Fourth
2006 Quarters				
High	$47.80	$44.80	$49.51	$50.99
Low	$42.88	$42.00	$43.26	$46.10
Cash distributions paid	$0.925	$0.925	$0.925	$0.925
2005 Quarters				
High	$55.66	$54.32	$57.08	$55.99
Low	$47.90	$48.75	$50.40	$42.00
Cash distributions paid	$0.925	$0.925	$0.925	$0.925

On February 21, 2007 the last reported sales price of our Class A common units on the NYSE was $52.58. At February 21, 2007, there were approximately 78,000 Class A common unitholders, of which there were approximately 2,000 registered Class A common unitholders of record. There is no established public trading market for our Class B common units, all of which are held by the General Partner, our Class C units, 50 percent of which are held by the General Partner and 50 percent of which are held by an institutional investor, or our i-units, all of which are held by Enbridge Management.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived, and should be read in conjunction with, our audited consolidated financial statements and notes thereto beginning at page F-1. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year ended December 31,				
	2006	2005	2004	2003	2002
	(dollars in millions, except per unit amounts)				
Income Statement Data:[(2)(3)(4)]					
Operating revenue	$6,509.0	$6,476.9	$4,291.7	$3,172.3	$1,185.5
Operating expenses	6,122.1	6,285.0	4,054.5	2,978.0	1,047.5
Operating income	386.9	191.9	237.2	194.3	138.0
Interest expense	(110.5)	(107.7)	(88.4)	(85.0)	(59.2)
Rate refunds	—	—	(13.6)	—	—
Other income (expense)	8.5	5.0	3.0	2.4	(0.2)
Minority interest	—	—	—	—	(0.5)
Net income	$ 284.9	$ 89.2	$ 138.2	$ 111.7	$ 78.1
Net income per limited partner unit (basic and diluted)[(1)]	$ 3.62	$ 1.06	$ 2.06	$ 1.93	$ 1.76
Cash distributions paid per unit	$ 3.70	$ 3.70	$ 3.70	$ 3.70	$ 3.60
Financial Position Data (at year end):[(2)(3)(4)]					
Property, plant and equipment, net	$3,824.9	$3,080.0	$2,778.0	$2,465.6	$2,253.3
Total assets	5,223.8	4,428.4	3,770.7	3,231.8	2,834.9
Long term debt, excluding current maturities	2,066.1	1,682.9	1,559.4	1,155.8	1,011.4
Loans from General Partner and affiliates	—	151.8	142.1	133.1	444.1
Partners' capital:					
Class A common units	1,141.7	1,142.4	1,021.6	914.9	604.8
Class B common units	67.6	67.2	66.7	64.2	48.7
Class C units	509.8	—	—	—	—
i units	466.3	421.7	399.4	370.7	335.6
General Partner	47.6	34.6	31.0	27.5	18.8
Accumulated other comprehensive (loss) income	(189.6)	(302.1)	(120.8)	(64.0)	(16.3)
Partners' capital	$2,043.4	$1,363.8	$1,397.9	$1,313.3	$ 991.6
Cash Flow Data:[(2)(3)(4)]					
Cash flows provided by operating activities	$ 321.6	$ 267.1	$ 245.4	$ 148.2	$ 200.8
Cash flows used in investing activities	(867.0)	(437.1)	(419.1)	(431.0)	(557.2)
Cash flows provided by financing activities	640.2	181.5	187.6	286.9	376.5
Acquisitions and capital expenditures included in investing activities, net of cash acquired	(897.7)	(531.2)	(429.8)	(423.5)	(563.9)

Notes to Selected Financial Data:

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating net income per unit: 2006, $30.9 million; 2005, $23.5 million; 2004, $22.5 million; 2003, $19.6 million; and 2002, $13.1 million.

(2) Our income statement, financial position and cash flow data reflect the following acquisitions and dispositions:

- April 2006, acquisition of a natural gas pipeline in east Texas;
- December 2005, disposition of assets on the East Texas and South Texas systems;
- January 2005, acquisition of the natural gas gathering and processing asset in north Texas;
- March 2004 acquisition of the Mid-Continent system;
- December 2003 acquisition of the North Texas system;
- October 2002 acquisition of the Midcoast system including natural gas gathering and transmission pipelines, and natural gas treating and processing assets in the Mid-continent and Gulf Coast regions of the United States;

(3) Our income statement, financial position and cash flow data include the effect of the following debt issuances:

- The December 2006 issuance of $300 million of senior unsecured notes;
- The September 2005 amendment of our credit facility to extend the letter of credit sublimit from $175 million to $300 million and increase the commitments available from $600 million to $800 million maturing in 2010, and the subsequent extension of the commitments available to $1 billion in March 2006.
- The April 2005 establishment of a $600 million commercial paper program;
- The December 2004 issuance of $300 million of senior unsecured notes;
- The April 2004 amendment of our credit facilities to terminate the 364-day revolving credit facility and increase the Three-year term credit facility to $600 million maturing in 2007;
- The January 2004 issuance of $200 million of senior unsecured notes;
- The May 2003 issuance of $400 million of senior unsecured notes; and
- The January 2002 replacement of the $350 million Revolving Credit Facility with a $300 million Three-year term credit facility and a $300 million 364-day Facility.

(4) Our income statement, financial position and cash flow data include the effect of the following limited partner unit issuances:

- The August 2006 issuance of approximately 10.8 million Class C units in equal amounts to our general partner and an institutional investor and subsequent Class C unit distribution of 0.2 million in lieu of cash distributions;
- The December 2005 issuance of 0.13 million Class A common units; the November 2005 issuance of 3.0 million Class A common units; and the February 2005 issuance of 2.5 million Class A common units;
- The September 2004 issuance of 3.68 million Class A common units; and the January 2004 issuance of 0.45 million Class A common units;
- The December 2003 issuance of 5.0 million Class A common units; and the May 2003 issuance of 3.9 million Class A common units;
- The March 2002 issuance of 2.3 million Class A common units; and
- The October 2002 issuance of 9.0 million i-units and subsequent quarterly i-unit distributions during 2006, 2005, 2004, 2003 and 2002, respectively, of 1.0 million, 0.8 million, 0.8 million, 0.8 million and 0.2 million, in lieu of cash distributions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our Consolidated Financial Statements and the accompanying notes beginning on page F-1 of this Annual Report on Form 10-K.

RESULTS OF OPERATIONS—OVERVIEW

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

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

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

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. Each of these systems largely consists of FERC-regulated interstate crude oil and liquid petroleum pipelines. Our Mid-Continent system is also one of the largest above ground crude oil storage facilities in North America, with the majority of the capacity available for contract storage not subject to regulation by the FERC. Each of these systems generates most of its revenues by charging shippers a per barrel tariff rate to transport and store crude oil and liquid petroleum.

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, including four FERC-regulated interstate natural gas transmission pipelines, as well as natural gas treating and processing plants and related facilities. The revenues of our Natural Gas segment are derived from the fees we charge to gather and process natural gas and the rates we charge to transport natural gas on our pipelines.

Our Marketing segment provides supply, transmission, storage and sales services to producers and wholesale customers on our gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Our Marketing activities are primarily undertaken to realize incremental revenue on gas purchased at the wellhead, increase pipeline utilization and provide other services that are valued by our customers.

Several types of arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide, or where we purchase natural gas or NGLs. We employ derivative financial instruments to reduce our exposure to natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of SFAS No. 133, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative financial instrument.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31:

	2006	2005	2004
		(in millions)	
Operating Income			
Liquids	$ 199.8	$ 127.3	$139.1
Natural Gas	133.9	110.5	98.1
Marketing	56.1	(42.4)	3.6
Corporate, operating and administrative	(2.9)	(3.5)	(3.6)
Total Operating Income	386.9	191.9	237.2
Interest expense	(110.5)	(107.7)	(88.4)
Rate refunds	—	—	(13.6)
Other income	8.5	5.0	3.0
Net Income	$ 284.9	$ 89.2	$138.2

Summary Analysis of Operating Results

Liquids

Our Liquids segment contributed operating income of $199.8 million in 2006, or $72.5 million more than the $127.3 million contributed in 2005. The operating income of our Liquids segment in 2006 was affected by the following factors:

- Higher volumes on our Lakehead system following completion of the repair and expansion of a major oil sands plant that was damaged by fire in early January 2005, partially offset by higher power costs associated with the increased volumes;
- The annual index rate increase effective July 1, 2006, which increased our average tariffs;
- Longer transportation hauls on our Lakehead system; and
- Lower oil measurement losses.

Natural Gas

Operating income from our Natural Gas segment grew to $133.9 million in 2006 representing an increase of $23.4 million over the $110.5 million generated in 2005. The increased contribution of our Natural Gas segment is attributable to the following:

- Average daily volume on our major natural gas systems was 13 percent greater in 2006 than in 2005, due to continuing investments to expand the capacity of our three largest natural gas systems. The volume and revenue growth is also the result of additional wellhead supply contracts and robust drilling activity in the Anadarko basin, Bossier Trend and Barnett Shale. Also contributing to the increase in volumes is an 80-mile pipeline we acquired in April 2006 that is complimentary to our existing East Texas system and provided approximately 75,500 million British thermal units per day, or MMBtu/d, of incremental volume.
- Increased processing capacity from the expansion of our existing Zybach processing facility on our Anadarko system that we completed in the second quarter of 2006 and the construction of our Henderson natural gas processing facility on our East Texas system completed in the third quarter of 2006.

- Favorable commodity prices where NGL and crude oil prices remained high relative to natural gas prices, which have declined from the high prices reached in late 2005, contributed to improved results from our processing activities.
- NGL purchase, transportation and fractionation costs that are predominantly associated with prior years were corrected in 2006, partially offsetting the increased contribution to operating income discussed above.
- Also partially offsetting the improvements to operating income noted above are increases in operating and administrative costs that are mostly variable with the incremental volumes gathered, processed and transported on our systems and the workforce related costs we are charged for the additional resources and related benefits necessary to operate and support our existing assets and the expansion of our natural gas systems. Additionally, our repair and maintenance costs have increased due to additional pipeline integrity and other work we perform to maintain the service capability of our systems.

Marketing

Operating income from our Marketing segment increased in 2006 from operating losses for the comparable period in 2005. The change in operating income from 2005 to 2006 resulted from the following:

- Unrealized, non-cash mark-to-market net gains for 2006 of $64.5 million compared with non-cash mark-to-market net losses of $50.3 million for 2005. The gains resulted from the change in market value of our derivative financial instruments that do not qualify for hedge accounting;
- Partially offsetting the unrealized mark-to-market gains is a non-cash charge of $17.0 million for the year ended December 31, 2006, resulting from a lower of cost or market accounting adjustment to the cost basis of our natural gas inventory. The market price for natural gas in various storage locations experienced declines during the year from the prices at which the inventory was purchased. We use derivative financial instruments to fix the price of our forecasted sales of inventory and as a result we expect that a majority of this charge will be offset by future financial and physical transactions that will settle at the time we sell the inventory.

Derivative Transactions and Hedging Activities

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

Declining natural gas prices during our fiscal year ended December 31, 2006, produced non-cash mark-to-market gains of $64.4 million and positively affected our operating results. Mark-to-market gains or losses create volatility in our results. The derivative financial instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains or losses to reverse in future periods as we settle the derivative financial instruments against the underlying physical transactions. Because of the economic benefit we receive by minimizing the volatility in our cash flows by using derivative financial instruments to hedge our portfolio of natural gas and NGLs, we intend to continue using them. Our continued use of derivative financial instruments may result in additional unrealized, non-cash gains or losses in the future.

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 (in millions)	December 31, 2004
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.

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota, and Mid-Continent systems. We provide a detailed description of each of these systems in Item 1.—Business. The following tables set forth the operating results and statistics of our Liquids segment for the periods presented:

	2006	2005	2004
	(dollars in millions)		
Operating Results			
Operating revenues	$512.8	$418.0	$409.3
Operating and administrative	141.3	144.2	128.9
Power	107.6	74.8	72.8
Depreciation and amortization	64.1	71.7	68.5
Operating expenses	313.0	290.7	270.2
Operating Income	$199.8	$127.3	$139.1
Operating Statistics			
Lakehead system:			
United States(1)	1,204	1,036	1,064
Province of Ontario(1)	313	303	358
Total deliveries(1)	1,517	1,339	1,422
Barrel miles (billions)	400	338	367
Average haul (miles)	722	692	706
Mid-Continent system deliveries(1)(2)	244	236	237
North Dakota system deliveries(1)	92	87	85
Total Liquids Segment Delivery Volumes(1)	1,853	1,662	1,744

(1) Average barrels per day in thousands.

(2) Ten months of deliveries in 2004.

Year ended December 31, 2006 compared with year ended December 31, 2005

Our Liquids segment accounted for $199.8 million of operating income in 2006, representing an increase of $72.5 million over 2005. The favorable results of the Liquids segment assets reflect continuing growth in our transportation volumes while actively managing the costs of our services. The majority of this increase related to significantly improved results on our Lakehead system.

Operating revenue in 2006 increased by $94.8 million to $512.8 million, compared with $418.0 million in 2005. As indicated in the table above, total delivery volumes of our Liquids segment averaged 1.853 million Bpd in 2006, representing a 0.191 million Bpd increase from the 1.662 million Bpd delivered in 2005. This accounted for an increase in operating revenues of approximately $48.0 million. The increases in deliveries on our Liquids systems are primarily derived from increased production of Western Canadian crude oil delivered on our Lakehead system. The increases in deliveries are attributable to the following:

- Suncor, an oil sands producer in Alberta, Canada, experienced a fire at its upgrade site in January 2005, which affected production for the majority of 2005. In late September 2005, Suncor completed repairs and an expansion to its upgrader site. Suncor's production levels have increased since that time.

- Conventional light, heavy crude oil and bitumen production have increased as existing and new facilities were commissioned during 2006.
- Syncrude, another oil sands producer in Alberta completed its Stage 3 expansion and initiated production on its Coker 8-3 unit in May 2006 enabling all Stage 3 units to be brought on line. However, shortly following start up, an ammonia leak resulted in its closure until August 2006. Additionally, as a result of a leak discovered in November, the Coker 8-2 unit was closed for turnaround into 2007. The Stage 3 expansion is designed to increase productive capacity from 250,000 Bpd to an average 350,000 Bpd of a light synthetic crude oil. Our deliveries in 2006 were marginally higher as a result of Syncrude's completion and start up of its Stage 3 expansion.

Contributing to the revenue growth of our Liquids segment are the increases in the average tariffs on all three of our Liquids systems. These tariff increases were partly the result of the annual index rate increase allowed by the FERC. On our Lakehead system, we increased our rates by an average of three percent. Also on our Lakehead system, new tariffs went into effect on April 1, 2006 for an adjustment on the Terrace expansion program surcharge due to lower than expected volumes moving on the Lakehead system, and new facilities in service, that were not operating during 2005. These tariff increases, along with the four percent increase in average hauls from 692 miles in 2005 compared with 722 in 2006 resulted in a combined increase in operating revenue of approximately $35.4 million.

Continuing volume growth related to our Mid-Continent storage terminal system in Cushing, Oklahoma, and El Dorado, Kansas, has resulted in an increase in operating revenue of approximately $6.8 million compared with 2005. Net capacity additions in 2006 bring the total storage capacity to 97 tanks and approximately 12.8 million barrels. This additional storage capacity is expected to provide ongoing fixed, variable, and spot storage revenue.

Operating and administrative expenses for 2006 were $141.3 million, or $2.9 million less than in 2005, primarily as a result of decreased oil measurement losses which are partially offset by increased workforce related costs and materials, supplies, and other general costs.

Workforce related costs increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our growing systems. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. We have experienced an increase in workforce related costs as a result of the growth and expansion of our Liquids system operations. We expect these costs will continue to increase in future periods as we continue to expand our Liquids system operations.

Materials, supplies and other, and Repair and maintenance costs were both higher in 2006 compared with 2005 due to higher pipeline inspection costs associated with our pipeline integrity management programs, increased outside contractor services, field inventory adjustments and other general costs.

Inventory adjustments include oil measurement losses, which occur as part of the normal operating conditions associated with our Liquids pipelines, include the following three elements:

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

During the fourth quarter of 2005, we identified certain operating conditions on connected third-party systems that were contributing to higher levels of physical losses on our Lakehead system. Improvements to our oil measurement processes have resulted in fewer physical losses during 2006 on our Lakehead and Mid-Continent systems. We expect these improvements to have a continuing positive impact on our oil measurement losses going forward.

Power costs increased $32.8 million in 2006, compared with 2005, primarily due to the increase in volumes transported on our Lakehead system and higher electricity rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas costs.

We completed a depreciation study of the Lakehead system in the first quarter of 2006 that resulted in extending the composite remaining service life of the system assets from 21.5 to 26 years. The impact of the depreciation study was an $11.0 million reduction of depreciation expense for the full year of 2006.

Year ended December 31, 2005 compared with year ended December 31, 2004

Our Liquids segment accounted for $127.3 million of operating income in 2005, representing a decrease of $11.8 million or eight percent over 2004. Lower results on the Lakehead system were modestly offset by stronger results on our North Dakota system and a full twelve-month contribution from our Mid-Continent system compared with a ten-month contribution for the same period in 2004.

Operating revenue in 2005 increased by $8.7 million or two percent to $418.0 million, compared with $409.3 million for 2004. Our Mid-Continent assets contributed higher operating revenue of approximately $6.6 million for the additional two months of ownership in 2005 compared to 2004. Overall tariff increases and longer hauls on our North Dakota system were mostly offset by lower deliveries on the Lakehead system during 2005.

Average daily crude oil deliveries on the Lakehead system decreased approximately 6 percent, from 1.422 million Bpd during 2004 to 1.339 million Bpd during 2005. This resulted in lower operating revenue for 2005 of approximately $20.0 million. The decrease is the result of lower than expected crude oil supply in western Canada from three factors. First, Suncor, an oil sands producer in Alberta, Canada, had a fire at their upgrader site on January 4, 2005. As a result of the incident, Suncor's production was reduced by an average of 89,000 Bpd during the first nine months of 2005. In late September, Suncor announced that repairs to the upgrader site and an expansion were completed and production capacity has increased as a result. Second, western Canadian crude oil supply available for delivery on our Lakehead system was also reduced during 2005 due to lower bitumen supplies. The nature of the cyclic steaming process used to extract bitumen from the ground can cause production timing differences during the year. Finally, during the second quarter of 2005, Kinder Morgan, Inc., an unrelated company, completed an expansion on its Express Pipeline system. The expansion increased capacity on this pipeline by approximately 108,000 Bpd. Given the volume commitments on the Express Pipeline expansion, coupled with the lower western Canadian crude oil supply as noted above, deliveries on our Lakehead system were negatively impacted for 2005. Management believes that holders of firm capacity on the Express Pipeline will first satisfy their commitments to that pipeline before moving incremental barrels on the Lakehead system.

Increases in average tariffs on all three Liquids systems resulted in higher operating revenue by approximately $17.6 million. These tariff increases were partly the result of the annual index rate increase of approximately 3.63% allowed by the FERC that became effective July 1, 2005, on our base system tariffs. On the Lakehead system, new tariffs also went into effect on April 1, 2005 for an adjustment on the Terrace expansion program surcharge due to lower than expected volumes moving on the Lakehead system. Longer hauls on our North Dakota system also contributed to higher average tariffs, as production in Montana continued to be strong during 2005.

Operating and administrative expenses for 2005 increased by $15.3 million to $144.2 million, compared with $128.9 million in 2004. The increase was attributable to the following factors:

(1) workforce related costs increased by approximately $6.9 million due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our growing systems;

(2) operating and administrative expenses on our Mid-Continent system increased approximately $2.9 million due to a full year's ownership in 2005, compared with ten months in 2004;

(3) capital project recoveries were lower by approximately $2.8 million due to a decrease in utilization of our workforce on capital projects and a reduction in construction activity on our Liquids systems;

(4) oil measurement losses increased approximately $2.4 million.

Oil measurement losses occur as part of the normal operating conditions associated with our Liquids pipelines. During 2005, the increase in oil measurement losses was a function of the following two factors:

- Higher volumetric physical losses associated with changes in commodity properties and measurement, coupled with higher oil prices that made the monetary value of normal physical losses more expensive. During 2005, the average West Texas Intermediate crude oil price was approximately $56 per barrel compared with approximately $41 per barrel during 2004;

- Wider light/heavy crude price differentials made degradation losses more expensive. During 2005, light/heavy differentials were approximately $21 per barrel compared with approximately $14 per barrel in 2004.

Power costs increased $2.0 million, or three percent, in 2005 compared with 2004, mostly due to higher electricity rates and a full twelve-month contribution from our Mid-Continent system compared to ten months in 2004, partially offset by lower energy consumption related to lower Lakehead volumes. Power costs associated with the Mid-Continent system increased approximately $1.5 million in 2005.

Depreciation and amortization increased $3.2 million, or five percent, in 2005 compared with 2004. The increase is driven primarily by a full twelve-month contribution from our Mid-Continent system and an increase in the depreciable asset base on our Lakehead system in 2005.

Future Prospects for Liquids

Historically, Western Canada has been a key source of oil supply serving U.S. energy needs. Canada's oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. Combined conventional and oil sands established reserves of approximately 179 billion barrels, compared with Saudi Arabia's proved reserves of approximately 260 billion barrels. The National Energy Board, or NEB, estimates that total 2006 Western Canadian Sedimentary Basin, or WCSB, production averaged approximately 2.3 million Bpd compared with 2.2 million Bpd in 2005. According to production forecasts by CAPP, Western Canadian crude oil production is projected to grow progressively from approximately 2.2 million Bpd in 2005 to 4.7 million Bpd by 2020. Conventional crude oil production is expected to decline from approximately 1.0 million Bpd to approximately 550,000 Bpd over the same period. The net increased production is expected to result from an estimated $82 billion of active or planned projects that are being developed in the oil sands. The projected growth in Western Canadian crude production will require construction of new pipelines to ensure new oil supplies can be transported to markets in the United States.

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

Partnership Projects

Southern Access

In conjunction with Enbridge, we announced in 2005 the approval of the 400,000 Bpd Southern Access expansion project, which received endorsement from CAPP, a trade association that represents a large majority of the Lakehead system's customers. We are undertaking the U.S. portion of the expansion on our Lakehead system and the first stage will add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. The project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in early 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

On March 16, 2006, the FERC approved an Offer of Settlement with respect to tariff principles for the Southern Access expansion, which were negotiated with CAPP. In July 2006, we obtained support from shippers and CAPP to increase the diameter of the new pipeline segments of the project from 36 inches, to which the previously negotiated tariff principles apply, up to 42 inches. The incremental capital cost of the larger diameter pipe is currently estimated at approximately $157 million, bringing our total estimated costs to approximately $1.3 billion. The larger diameter will not provide increased capacity in the near term but does increase the ultimate capacity of the line from 800,000 Bpd to 1,200,000 Bpd with expenditures for additional pumping equipment. This places us in a favorable position to secure future expansion opportunities for our Lakehead system. We will defer any return on the incremental capital until the additional capacity is required by shippers (see discussion of Alberta Clipper project below). In the interim, shippers will absorb all the incremental operating costs of the larger diameter line but will benefit from reduced power costs at higher throughput levels. Delivery of line pipe to the right of way has commenced to ensure full completion in early 2009.

Alberta Clipper

Based on forecasts of oil sands production growth prepared by Enbridge, as well as forecasts by CAPP, we believe that there will be a need for additional export pipeline capacity out of Western Canada over and above projects which have already received shipper support. Based on this analysis, as well as interest expressed by shippers, we and Enbridge are planning to develop the Alberta Clipper project. This project will involve construction of a 36-inch diameter heavy crude line from Hardisty, Alberta to Superior, Wisconsin in conjunction with additional pumping power applied to the Southern Access 42-inch pipe from Superior to Flanagan. We anticipate that our share of the cost of this project, as currently proposed, will approximate $0.8 billion in 2006 dollars, excluding both capitalized interest and the approximate cost of $157 million to "prebuild" Southern Access to 42 inches as discussed above.

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

North Dakota

Work is proceeding on our previously announced North Dakota system expansion. Three critical hydrostatic pressure tests have been successfully completed and the North Dakota Public Service Commission approvals have been obtained for all phases of the project. The expansion will add approximately 30,000 Bpd of mainline throughput capacity and expand the system's feeder segment by approximately 30,000 Bpd at an estimated cost of $70 million. The expansion is supported by increasing crude oil production from the Williston Basin in Montana and North Dakota and is expected to be completed in phases throughout 2007, with the final completion dates scheduled in the fourth quarter of 2007.

Superior and Griffith Storage

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

Cushing Terminal Storage

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

Enbridge and Other Projects

Spearhead Reversal

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Cushing to Chicago, Illinois. The pipeline, renamed Spearhead, began delivering Canadian crude oil to the major oil hub at Cushing in March 2006 and has ongoing capacity of approximately 125,000 Bpd. We have benefited from reversal of the pipeline due to Western Canadian crude oil being carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline.

Pegasus Reversal

In April 2006, ExxonMobil completed the reversal of two of its crude oil pipelines allowing up to 66,000 Bpd of Canadian crude oil to flow from the U.S. Midwest to the U.S. Gulf Coast. The combined reversed pipeline is linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka, Illinois. The Mustang Pipe Line Partners system is 30 percent owned by an affiliate of Enbridge. ExxonMobil has firm commitments from Canadian shippers for an average of 50,000 Bpd of capacity on the lines from Patoka, to Nederland, Texas for the next five years. The connection of our Lakehead system with this new market supports increased throughput on our Lakehead system; however, the reversed ExxonMobil system is also capable of transporting Western Canadian crude oil moved via other competing pipelines into the Patoka market.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and CAPP for its 36-inch diameter Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project is scheduled for completion in the first quarter of 2009 and will be undertaken by Enbridge; however, we will benefit through incremental volumes moving through our Lakehead system to reach this extension. The Offer of Settlement filed in September 2006 was rejected by the FERC because of its rolled-in toll design. However, support for the project remains high and Enbridge is working with shippers to prepare an alternative tolling structure to address the initial opposition. The second application is expected to be filed with the FERC in the first quarter of 2007 and will allow the project to proceed on schedule.

Southern Lights

During the third quarter of 2006, Enbridge completed a successful open season on its Southern Lights diluent pipeline from Chicago, Illinois to Edmonton, Alberta. The Southern Lights pipeline responds to interest from a number of western Canadian producers to increase the availability of crude oil diluent in Alberta. Diluent is required to transport the heavy oil and bitumen being produced in increasing volumes from the Alberta oil sands. The project involves the exchange of a 156-mile section of pipeline we own for a similar section of a new pipeline to be constructed as part of the project. We expect to benefit from increased heavy crude shipments, which will be facilitated by the diluent line. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us. This project is expected to be in service during 2010.

U.S. Gulf Coast Access

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

Eastern PADD II Access

Enbridge has held discussions with several refiners in the eastern United States to gauge interest in supporting the development of a pipeline to provide incremental pipeline capacity to this market. The level of interest has increased significantly during the latter part of 2006. Enbridge is currently in discussions with interested parties to develop a pipeline to deliver at least 200,000 Bpd of incremental Canadian supply from the Chicago area to the eastern region of PADD II. This project would be complementary to the Partnership's mainline system.

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

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, as well as treating and processing plants and related facilities. Collectively, these systems include:

- approximately 11,000 miles of natural gas gathering and transmission pipelines including four FERC-regulated transmission pipeline systems;
- nine natural gas treating plants;
- seventeen natural gas processing plants; and
- trucks, trailers and railcars used for transporting NGLs, crude oil and carbon dioxide.

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

	Year Ended December 31,		
	2006	2005	2004
	(dollars in millions)		
Operating revenues	$3,020.7	$2,352.1	$1,319.9
Cost of natural gas	2,601.1	2,018.7	1,031.8
Operating and administrative	215.4	175.0	138.3
Depreciation and amortization	70.3	66.0	51.7
Gain on sale of assets	—	(18.1)	—
Expenses	2,886.8	2,241.6	1,221.8
Operating income	$ 133.9	$ 110.5	$ 98.1

	Year Ended December 31,		
Average Daily Volume (MMBtu/d)	2006	2005	2004
East Texas[1]	1,019,000	860,000	676,000
Anadarko	582,000	488,000	357,000
North Texas	294,000	265,000	192,000
South Texas[1]	—	33,000	40,000
UTOS	181,000	158,000	219,000
Midla	109,000	106,000	103,000
AlaTenn	41,000	59,000	62,000
KPC	29,000	31,000	48,000
Bamagas	88,000	29,000	25,000
Other Major Intrastates	158,000	186,000	176,000
Total	2,501,000	2,215,000	1,898,000

(1) In December 2005, we sold the South Texas assets and a sour gas system in East Texas which had a combined average daily volume of approximately 55,000 MMBtu/d.

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

Commodity-based Arrangements:

We use several types of contractual arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. We will continue to hedge a significant amount of our commodity price risk to support the stability of our cash flows. Refer to Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk and Note 15 of our Consolidated Financial Statements beginning on page F-1 of this report for more information about our derivative activities.

Our commodity-based arrangements are categorized as follows:

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

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

Fee-Based Arrangements:

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

Year ended December 31, 2006 compared with year ended December 31, 2005

Our Natural Gas segment contributed $133.9 million of operating income in 2006, an increase of $23.4 million from the $110.5 million it contributed in 2005. The increase in operating income is primarily attributable to favorable commodity prices which contributed to higher revenue generated by our processing assets in excess of the cost we incur for the natural gas used in processing. Additionally, operating income was higher due to volume increases on each of our three largest systems resulting from additional wellhead supply contracts and the expansion of our transportation and processing capacity. Partially offsetting the benefit provided by favorable volumes and commodity prices are expenses we recorded in 2006 of approximately $8.3 million for NGL purchases and transportation and fractionation charges that relate to prior years we had not previously recorded. Our 2006 volumes and operating results are exclusive of the volumes and operating results associated with our December 2005 sale of the South Texas assets and a sour gas system located on our East Texas system.

Average daily volumes on our major natural gas systems were up approximately 13 percent in 2006, compared with 2005. Increases in our volumes for 2006 are attributable to our ongoing investments to expand the capacity of our systems and services. Our investments in the following projects that were completed during 2006 contributed to the increase in the average daily volumes and operating results on our major natural gas systems:

- The link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005;
- Construction of our 120 MMcf/d Henderson natural gas processing facility on our East Texas system was completed at the end of the third quarter of 2006 and processed volumes of approximately 100 MMcf/d;
- The expansion of our existing Zybach processing facility on our Anadarko system to a capacity of 150 MMcf/d of natural gas from an initial capacity of 105 MMcf/d to meet the continuing demands resulting from rapid development in the Anadarko basin; and
- Acquisition of an 80-mile pipeline in April 2006 that is complimentary to our existing East Texas system that provided approximately 75,000 MMBtu/d of incremental volume.

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

Throughout a majority of 2006, we have experienced a favorable pricing environment with regard to our processing assets and our keep-whole processing. During 2006, NGL and crude oil prices remained high relative to natural gas prices which have declined from the high prices reached in late 2005. As a result of this favorable pricing environment, the revenue generated by our processing assets less the cost of natural gas used for processing was approximately $40 million greater than the amounts we realized in 2005. This increase includes the contribution to operating income derived from our keep-whole processing of $60.3 million for the year ended December 31, 2006, in excess of the $29.0 million generated in 2005 under this contract structure. Due to the volatility associated with commodity prices, the revenue less cost of natural gas we derive from our processing activities in future periods could be adversely affected if the pricing environment becomes unfavorable, which can occur if the prices for NGLs substantially decline and the price of natural gas significantly increases. We attempt to hedge a majority of our mandatory processing to minimize the effects volatility in commodity prices can have on our processing activities.

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

Operating income of our Natural Gas segment for the year ended December 31, 2006 includes unrealized non-cash, mark-to-market net losses of $0.1 million, including $1.9 million of losses resulting from ineffectiveness of our cash flow hedges and $1.8 million of gains derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. In 2005, our operating income was reduced by $8.1 million of unrealized, non-cash, mark-to-market net losses that we incurred, primarily from derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The decline in our unrealized derivative fair value losses in 2006 is largely due to a decline in the current and forward prices of natural gas and NGLs during 2006 from the high levels reached in 2005 due to hurricanes Rita and Katrina that caused supply disruptions in the Gulf of Mexico resulting in a volatile pricing environment. Additionally, our unrealized derivative fair value losses in 2006 are lower due to our settlement in December 2005 for $16.3 million of natural gas collars on 2,000 MMBtu/d of natural gas through 2011 that did not qualify for hedge accounting treatment under SFAS No. 133. The settlement of these natural gas collars reduces the quantity of derivatives outstanding that do not qualify for hedge accounting treatment in our Natural Gas segment, effectively reducing the unrealized mark-to-market adjustments resulting from these derivatives in periods following settlement (refer also to Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk and Note 15 of our Consolidated Financial Statements beginning on page F-1 of this report for more information about our derivative activities).

Operating and administrative costs of our Natural Gas segment were $215.4 million, or 23 percent, greater for 2006 than 2005, primarily as a result of increased workforce related costs, maintenance activities and other costs that are mostly variable with volumes. Workforce related costs have increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of continuous pipeline expansions across the areas we serve. We anticipate that our workforce related costs will continue to increase as we expand our natural gas operations.

The increase in our Materials, supplies and other costs along with our Repair and maintenance costs are predominantly related to the increase in volumes and expansion of our natural gas systems. Materials, supplies and other costs include chemicals used in our processing activities, materials purchased for repair and maintenance purposes, utility costs to run our plants, pumps and other similar costs that are mostly variable with volumes. These costs were partially offset by the sale of our South Texas assets and a sour gas system located on our East Texas system in December 2005, which contributed to the decrease in Materials, supplies and other costs compared with 2005. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. During 2006, we spent approximately $10.1 million, the majority of which was in the fourth quarter of 2006, on pipeline integrity work in connection with our ongoing pipeline integrity management program in order to comply with regulatory guidance and maintain our existing pipeline integrity standards. We anticipate these costs will continue to increase as we expand our systems and increase the volumes of natural gas services we provide.

Our other operating and administrative costs include rents and leases which primarily relate to compressor rentals, property taxes and other costs. These additional operating and administrative costs tend to vary in relation to the natural gas volumes moving on our systems or in relation to the expansion of our natural gas operations. We anticipate these costs will continue to increase as the volumes on our systems increase and we expand our systems.

We expect our operating and administrative costs will continue to increase in future periods as greater volumes of natural gas flow through our systems and we continue to expand our natural gas operations.

Our depreciation and amortization expense for the year 2006 exceeded the amount reported for 2005 by approximately $4.3 million, primarily as a result of capital projects completed and placed in-service during 2006 and projects completed in 2005 that were only depreciated for a partial year. The increase in depreciation expense was partially offset by modest extensions of the depreciable lives of our major natural gas systems based on a third-party study commissioned by management that was completed in the third quarter of 2005. As a result of this study, revised depreciation rates for the Anadarko, North Texas and East Texas systems were implemented effective August 1, 2005. The annual composite rate, which represents the expected remaining service life of these natural gas systems, was reduced from 4.0% to 3.4%. As a result, our depreciation expense was approximately $3.5 million and $2.5 million lower for the years ended December 31, 2006 and 2005, respectively, than if these rates had not been reduced. Additionally, we revised our depreciation rates for a portion of our FERC-regulated natural gas assets effective July 1, 2006, to reflect a decrease in the remaining service life of these natural gas assets. Depreciation expense was approximately $1.3 million higher for the year ended December 31, 2006, as a result of this decrease in the expected remaining service life of these assets.

Year ended December 31, 2005 compared with year ended December 31, 2004

Our Natural Gas segment contributed $110.5 million of operating income in 2005, representing an increase of $12.4 million from the $98.1 million earned in 2004. Increased drilling by producers contributed to average daily volume increases of 17 percent in 2005 on our major natural gas systems compared with 2004. The increase in volumes is primarily the result of additional wellhead supply contracts on our East Texas and Anadarko systems, as well as the additional volumes on the North Texas system associated with the gathering and processing assets we acquired in January 2005. Drilling activity continues to increase in the Anadarko Basin, Bossier Trend and Barnett Shale areas as evidenced by increasing rig counts and production volumes over the past several years. Additionally, completion of the East Texas expansion project in late June 2005 contributed modestly to the growth in volumes for the year 2005. With continued investment in our systems to expand capacity, we expect our major natural gas systems to benefit from the increase in production volumes expected to result from the continuing increase in drilling activities in the basins we serve.

Partially offsetting the positive operating results derived from the increases in gathering, processing and transportation volumes on our natural gas systems were non-cash, mark-to-market net losses of $8.1 million associated with our derivative transactions and hedging activities. Included in Cost of natural gas are non-cash losses of $2.5 million resulting from ineffectiveness associated with our qualified cash flow hedges and $5.6 million of non-cash mark-to-market losses from derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The non-cash losses primarily result from the significant increases in forward natural gas and NGL prices during the year. The increase in prices reduces the fair market value of these derivative financial instruments because the fixed price component of these derivatives is significantly less than the market price of natural gas at each of the forward settlement points.

Also included in our operating results for the year ended December 31, 2005 is a gain of $18.1 million we realized in December 2005, when we divested non-strategic assets located within our East and South Texas systems. We sold for $105.4 million in cash, a processing plant and related facilities, and other gathering and processing assets with a carrying value of approximately $86.9 million. We incurred selling costs of approximately $0.4 million. In connection with this sale, we paid approximately $16.3 million to settle natural gas hedges associated with the natural gas produced by these assets. We had previously recorded unrealized losses associated with the natural gas hedges that were realized upon settlement.

A variable element of the Natural Gas segment's operating income is derived from keep-whole processing of natural gas primarily on our Anadarko and East Texas systems. This contract structure requires us to process natural gas at times when it may not be economical to do so. This can happen when natural gas prices are unusually high or NGL prices are unusually low. During 2005, although natural gas prices were unusually high, they were more than offset by favorable NGL prices. Operating revenue less cost of natural gas derived from keep-whole processing for the year 2005 was approximately $29.0 million compared with $17.2 million in 2004.

Operating and administrative costs of our Natural Gas segment were $175.0 million, or 27 percent greater for 2005 than 2004, primarily as a result of increased workforce related costs and costs that are variable with volumes. Workforce related costs increased $11.8 million due to higher pension, medical and other benefits, as well as additional administrative, regulatory and compliance support. Costs that are incremental with volumes, such as chemicals, materials and supplies and direct workforce expenses increased by $10.5 million. Additionally, the natural gas gathering and processing assets we acquired in January 2005 contributed to the cost increases of approximately $7.2 million. As well, our maintenance costs increased by approximately $4.9 million in 2005 due to several processing plants that underwent major repairs, one of which was included with the recently divested assets.

Our depreciation and amortization expense for the year 2005 exceeded the amount reported for 2004 by approximately $14.3 million, primarily as a result of acquisitions and significant capital projects completed and placed in-service during 2005. The increase in depreciation expense was partially offset by modest extensions of the depreciable lives of our major pipeline systems as a result of a depreciation study completed during the third quarter of 2005. Based on a third-party study commissioned by management, revised depreciation rates for the Anadarko, North Texas and East Texas systems were implemented effective August 1, 2005. The annual composite rate, which represents the expected remaining service life of these natural gas systems, was reduced from 4.0% to 3.4%. Depreciation expense for the year ended December 31, 2005 was approximately $2.5 million lower as a result of the new depreciation rates.

Future Prospects for Natural Gas

Our natural gas assets are located in the Gulf Coast and Mid-continent regions of the United States, two of the premier natural gas producing areas. As a result, there are many opportunities to connect new natural gas supplies either by installing new facilities or acquiring adjacent third-party gathering operations. Consolidation with neighboring facilities will extract efficiencies by eliminating costs, for example, by combining redundant facilities, increasing volume, and increasing processing margins. These opportunities tend to involve modest amounts of capital with attractive rates of return.

Although we continue to assess various acquisition and expansion opportunities to pursue our strategy for growth, the market for acquiring energy transportation assets continues to remain active and significant competition persists among prospective acquirers of assets. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. Although one of our objectives is to grow our natural gas business through acquisitions, we may and have pursued opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During 2006, increased drilling in the areas where our gathering systems are located has generally contributed to our volume growth. We expect the growth trend in these areas to continue in the future as evidenced by third-party reserve studies and the increase in rig counts in the areas served by our systems. Continuing advances in seismic and drilling completion technology, along with robust energy prices, have been key drivers for the higher drilling activity levels in such areas as the tight gas and gas shale locations of the Mid-Continent and East Texas. Other advances in drilling technology are enabling producers to more economically extract natural gas from wells and increase well productivity.

One of the prominent areas in which this is occurring is the Barnett Shale play in North Texas. The Barnett Shale is a prominent natural gas formation within the Fort Worth Basin, and it is being actively developed. The formation production has risen from approximately 110 MMcf/d to over 1,800 MMcf/d since 1999, with the drilling of over 5,200 wells. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of Barnett Shale development. To accommodate anticipated growth in the region we have commenced construction of two new gas processing plants totaling approximately 75 MMcf/d of capacity and related upstream facilities. These facilities are expected to become operational in the second and fourth quarters of 2007.

Our Anadarko system continues to experience considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. We are continuing to make progress in increasing processing capacity and field compression in the region from 230 MMcf/d at December 31, 2005 to approximately 440 MMcf/d to accommodate the volume growth. We have added approximately 70 MMcf/d of processing capacity during 2006 and expect to place 155 MMcf/d of additional processing capacity as well as field compression in service during 2007.

Producer drilling plans in regional plays, in the areas served by our gas assets, are expected to result in continued production growth. To accommodate this further growth we initiated construction on several projects during 2006 to increase our gathering and treating infrastructure and market access capability. These projects continue to progress according to schedule and include:

- Our expansion and extension of our East Texas natural gas system includes construction of a 36-inch diameter intrastate pipeline from Bethel, Texas to Orange County, Texas with capacity of approximately 700 MMcf/d. We expect to complete this project in stages throughout 2007. The new pipeline will provide service to a number of major industrial companies in Southeast Texas and will cross a number of interstate pipelines. We continue to secure additional commitments for capacity on the pipeline. We currently anticipate the expansion project will cost approximately $610 million.

- As part of our East Texas expansion project we are adding a 200 MMcf/d treating facility to be built near Marquez, Texas which will be connected to the 36-inch diameter intrastate pipeline via a new 24-inch diameter pipeline. We expect the plant to be completed and operating in the first quarter of 2007.

- Expansion of our sour gas treating capacity on the East Texas system will increase the total sulfur capacity in the first half of 2007 from 72.5 tons per day (tpd) to 125 tpd by early 2008, in order to handle additional sour gas supply and higher concentration levels of hydrogen sulfide (H_2S).

- Installation of additional processing plants to enable the East Texas system to meet the increasingly more stringent pipeline gas quality specifications by late 2007.

- The installation of two processing plants to expand the processing capability of our North Texas system, with processing capacities of 35 MMcf/d and 40 MMcf/d, to be fully operational in early 2007.

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

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

Other Matters

Our Bamagas system has agreements to provide transportation of up to 276,000 MMbtu/d of natural gas for a remaining period of 17 years to two utility plants that are indirectly owned by Calpine Corporation ("Calpine"). Calpine is the sole customer served by the Bamagas system. The Bamagas system receives a fixed demand charge of $0.07 per MMBtu of natural gas for 200,000 MMBtu/d, regardless of whether the capacity is used. In December 2005, Calpine and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. In connection with the bankruptcy filing, Calpine has announced receipt of commitments for up to $2 billion of Debtor in Possession, or DIP, financing to allow for the continued operation of its power plants. Our Bamagas system is the sole supplier of natural gas to these two utility plants, and we expect the subsidiary that owns these utility plants to continue performing under the terms of our agreement. Due to the recent nature of the bankruptcy filing, we are unable to determine the extent of any losses to which we may be subject as a result of the bankruptcy. In April 2006, Calpine announced its intent to sell approximately 20 of its non-core and non-strategic power plants, although all of the plants to be sold have not been announced. Calpine has continued to perform under the terms of its agreement with Bamagas and we remain confident that any losses we may incur with respect to Calpine's bankruptcy will be minimal. We continue to monitor the Calpine bankruptcy proceedings and will recognize any losses that may result when it becomes evident that a loss has been incurred.

Marketing

The following table sets forth the operating results for the Marketing segment assets for the periods presented:

	Year Ended December 31,		
	2006	2005	2004
	(dollars in millions)		
Operating revenues	$2,975.5	$3,706.8	$2,562.5
Cost of natural gas	2,913.5	3,744.6	2,555.3
Operating and administrative	5.4	4.1	3.4
Depreciation and amortization	0.5	0.5	0.2
Expenses	2,919.4	3,749.2	2,558.9
Operating income (loss)	$ 56.1	$ (42.4)	$ 3.6

Natural gas purchased and sold by our Marketing segment is priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At their request, we will enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedged positions under the same or similar terms.

Marketing pays third-party storage facilities and pipelines for the right to store and transport natural gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities.

Year ended December 31, 2006 compared with year ended December 31, 2005

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

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

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

For the year ended December 31, 2006, the operating income of our Marketing segment increased $98.5 million to $56.1 million, from a loss of $42.4 million in 2005. The significant increase in the operating income of our Marketing segment for 2006 is primarily due to unrealized, non-cash, mark-to-market net gains of approximately $64.5 million compared with unrealized mark-to-market net losses of $50.3 million for 2005. These unrealized mark-to-market changes are associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The unrealized, mark-to-market gains for 2006 are the result of a decline in the forward and daily market price of natural gas from the historically high prices experienced in 2005. Additionally, the basis between the index where the natural gas is purchased and the index where the natural gas is sold has declined in correlation with the decline in the forward market price of natural gas contributing to the unrealized, mark-to-market net gains for 2006.

The operating results of our Marketing segment for the year ended December 31, 2006, also include non-cash charges totaling $17.0 million attributable to reducing the cost basis of our natural gas inventory to fair market value. Natural gas prices as published by Platt's *Gas Daily* for Henry Hub were approximately $10.08 per MMBtu at December 31, 2005, which had declined to $5.64 per MMBtu at December 31, 2006. As a result of the decline in the price of natural gas from 2005 to 2006, we recorded charges totaling $17.0 million during 2006 to reduce the cost basis of our inventory to fair market value. Partially offsetting this charge are gains of approximately $3 million that we realized upon settlement of derivative financial instruments hedging our natural gas inventory for 2006. Due to our hedging structures, we expect that a majority of the lower of cost or market inventory charges will be offset by future financial and physical transactions that will settle at the time the natural gas inventory is sold.

Year ended December 31, 2005 compared with year ended December 31, 2004

For the year ended December 31, 2005, our Marketing segment incurred losses of $42.4 million, which include non-cash mark-to-market losses of $48.2 million, compared with earning $3.6 million of operating income for 2004. The non-cash, mark-to-market losses are associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. During 2005, we revised our business strategy for the use of derivative financial instruments associated with the transportation and storage of natural gas to afford us the ability to respond to changing economic conditions. The flexibility provided by our revised strategy precludes us from continuing the use of hedge accounting with regard to these transactions. Under SFAS No. 133, if the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation, the financial instruments must be marked-to-market each period with the change in fair market value recorded in earnings. However, SFAS No. 133 does not allow us to mark-to-market the change in value of the related underlying physical transaction, and this difference creates earnings volatility when the "spreads" shift. We expect these net mark-to-market losses to be predominantly offset when the related physical transactions are settled (refer also to the discussion included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 15 of our Consolidated Financial Statements beginning on page F-1 of this report).

During the third and fourth quarters of 2005, disruptions of natural gas supplies from facilities in the Gulf of Mexico region caused by hurricanes Katrina and Rita created greater demand for natural gas production from our onshore Natural Gas segment pipeline assets, increasing our ability to optimize natural gas supply to areas of strongest demand. As a result of the hurricanes, unusual volatility in the prices of natural gas created greater spreads on our natural gas volumes.

Corporate

Year ended December 31, 2006 compared with year ended December 31, 2005

Interest expense was $110.5 million in 2006 compared with $107.7 million in 2005. The increase is the result of higher debt balances and weighted average interest rates, partially offset by approximately $10.7 million of interest capitalized on our construction projects for 2006 compared with $4.0 million capitalized in 2005. Our weighted average interest rate was approximately 5.82% for the year ended December 31, 2006, compared with approximately 5.78% during 2005. Our debt balances are higher at December 31, 2006 compared with December 31, 2005 as a result of the capital expenditures we have made to expand our existing systems to improve the service capabilities of our assets.

Included in other income for the year ended December 31, 2006, is approximately $4.5 million that we received as settlement for an insurance claim that we filed in connection with an interruption to the operations of our Lakehead system resulting from a fire that occurred at Suncor's upgrader site in January 2005.

The Partnership is not a taxable entity for U.S. federal income tax purposes and historically has not been a taxable entity for state income tax purposes. Federal and state income taxes on partnership taxable income were both borne directly by the unitholders with no entity level tax on the Partnership. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by imposing a new tax based upon modified gross revenue. We determined that this tax is an income tax as defined under Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("SFAS No. 109"). Our initial accounting for the enactment of this income tax did not materially affect our results of operation, financial condition or cash flows. Although we anticipate Texas will make further changes to this tax in 2007 that may impact our income tax expense, our 2007 income tax expense will be approximately $5 million.

Year ended December 31, 2005 compared with year ended December 31, 2004

Interest expense was $107.7 million in 2005 compared with $88.4 million in 2004. The increase is the result of higher debt balances and higher weighted average interest rates of approximately 5.78% for the year ended December 31, 2005, compared with approximately 5.56% during 2004. The increase in our debt balances at December 31, 2005 is due to the gathering and processing assets in North Texas we acquired in January 2005, in addition to the capital expenditures we have made to expand our existing systems to improve the service capabilities of our assets.

LIQUIDITY AND CAPITAL RESOURCES

General

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

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

Capital Resources

Equity Capital

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity markets to obtain the capital necessary to fund these projects. During 2006, we raised net proceeds of approximately $500.0 million of equity in a private transaction for the sale of approximately 10.8 million of our Class C units, representing a new class of our limited partner interests. We sold the Class C units in equal amounts of approximately 5.4 million units each to our general partner and an institutional investor. Additionally, our general partner contributed approximately $10 million to maintain its two percent general partner interest. We used the proceeds from this issuance partially to reduce borrowings outstanding under our commercial paper program and to fund a portion of our capital expansion projects. We invested the remaining amount in short-term commercial paper for use in future periods to further reduce our commercial paper borrowings or fund additional expenditures under our capital expansion projects.

The following table presents historical information about our public equity offerings since January 2004:

Issuance Date	Number of Class A common units Issue	Offering Price per Class A common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		($ in millions, except per unit amounts)			
2006					
We did not issue any Class A common units during 2006.					
2005					
December	136,200	$46.000	$ 6.0	$0.2	$ 6.2
November	3,000,000	$46.000	132.1	2.8	134.9
February	2,506,500	$49.875	124.8	2.7	127.5
2005 Totals	5,642,700		$262.9	$5.7	$268.6
2004					
September	3,680,000	$47.900	$168.6	$3.6	$172.2
January	450,000	$50.300	21.6	0.4	22.0
2004 Totals	4,130,000		$190.2	$4.0	$194.2

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Available Credit

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

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

Indebtedness and Other Payment Obligations

The following table presents the components of our outstanding indebtedness:

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

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

Commercial Paper Program

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

Credit Facility

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

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

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

First Mortgage Notes

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

Senior Notes

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

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

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

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

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

Loans from General Partner and affiliates

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

Credit Ratings

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

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

NR—No rating is available

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

Summary of Obligations and Commitments

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

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

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

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

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

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

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

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. Extensive volume growth in the areas served by our East Texas system and the resulting constraints in reaching primary market locations necessitates the construction of additional pipeline capacity to transport these volumes to alternate natural gas markets. Anticipated growth in Western Canadian oil sands production and the need to reach newer markets has prompted the Southern Access, Alberta Clipper and related projects associated with our liquid systems. In 2007, we expect to spend approximately $1.5 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. At December 31, 2006, we had approximately $451.8 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2007.

Forecasted Expenditures

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

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

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

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through December 31, 2006, the incremental capacity that will become available upon completion of the project and the periods we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures		Estimated Incremental Capacity			
	Projected Total Cost (in billions)	Actual Expenditures through 2006 (in millions)	Storage (MBbl)	Oil (Mbpd)	Natural Gas (MMcf/d)	Expected Completion
Southern Access expansion (Lakehead)	$1.3	$110	—	400	—	In phases to early 2009
Clarity (East Texas)	0.6	325	—	—	700	In phases to late 2007
Alberta Clipper	0.8	—	—	450	—	Late 2009 to early 2010
North Dakota system expansion	0.1	11	—	30	—	Late 2007
Cushing terminal storage tanks	0.1	39	4,970	—	—	various
Griffith and Superior storage tanks.	0.1	10	1,220	—	—	Mid-2007 and Mid-2008
Natural gas connects and compression	0.1	62	—	—	—	Various
Processing and treating plant expansions	0.3	142	—	—	1,130	Various
Total	$3.4	$699	6,190	880	1,830	

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

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

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

Acquisitions

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

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

Derivative Activities

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments at December 31, 2006 for each of the indicated calendar years:

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

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

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

Operating Activities

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

Investing Activities

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

Financing Activities

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

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

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

Cash Distributions

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

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

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

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

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

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

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements.

Subsequent Events

Distribution to Partners

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

Line 14 Leaks

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

In February 2007, a contractor undertaking work in Rusk County, Wisconsin on the Enbridge Southern Lights project punctured the adjacent Line 14 pipeline, resulting in a release of crude oil estimated at 3,000 barrels. As the spill was largely contained within the ditch used for construction, environmental impact was minimized. Impact to customers was minimized as the line was repaired and returned to service in less than two days. We are investigating this incident and will record costs associated with the repair and cleanup as such amounts are determined.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

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

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

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

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

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

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

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

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

Assessment of Recoverability of Goodwill and Intangibles

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

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

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

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

Asset Retirement Obligations

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

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

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

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). To reduce the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities and fix the interest rate on our variable rate debt.

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

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

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

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

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

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

Gains and losses that we have deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter.

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

Commitments, Contingencies and Environmental Liabilities

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

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

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

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

Operational Balancing Agreements and Natural Gas Imbalances

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

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Fair Value Measurements

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

Accounting for Registration Payment Arrangements

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

Staff Accounting Bulletin No. 108

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

INTEREST RATE RISK

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

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

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

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates.

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

	December 31, 2006									December 31, 2005		
	Expected Fiscal Year of Maturity of Notional Amounts											
	Notional Amount	2007	2008	2009	2010	2011	Thereafter	Fair Value		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.

SUMMARY COMPENSATION TABLE

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

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

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

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

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

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

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

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

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

ALL OTHER COMPENSATION
(year ended December 31, 2006)

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

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

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

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

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

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

GRANTS OF PLAN-BASED AWARDS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

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

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

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

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

OPTION EXERCISES AND STOCK VESTED

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

Pension Plan

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

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

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

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

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

PENSION BENEFITS

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

Employment and Severance Agreements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Director Compensation

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

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

DIRECTOR COMPENSATION

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

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

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

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

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

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

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

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

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

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

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

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

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

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

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

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

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

* Less than 1%.

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

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

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

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

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

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

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

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

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

CASH DISTRIBUTIONS

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

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

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

IN-KIND DISTRIBUTIONS

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

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

OTHER RELATED PARTY TRANSACTIONS

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

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

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

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

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

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

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

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

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

Item 14. Principal Accountant Fees and Services

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

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

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

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

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

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

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

- a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
- b. Consolidated Statements of Income for the years ended December 31, 2006, 2005, and 2004.
- c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2006, 2005, and 2004.
- d. Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005, and 2004.
- e. Consolidated Statements of Financial Position as of December 31, 2006 and 2005.
- f. Consolidated Statements of Partners' Capital for the years ended December 31, 2006, 2005, and 2004.
- g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

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

(3) *Exhibits.*

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

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

Date: February 22, 2007

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

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

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

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

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

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

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

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

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

Index to Exhibits

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 of the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 16, 2006).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 of the Partnership's 2000 Form 10-K/A dated October 9, 2001).
4.2	Registration Rights Agreement, dated August 15, 2006, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K dated August 16, 2006).
10.1	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (incorporated by reference to Exhibit 10.10 of the Partnership's 1991 Form 10-K).
10.2	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (incorporated by reference to Exhibit 10.11 of the Partnership's 1991 Form 10-K).
10.3	Contribution Agreement (incorporated by reference to Exhibit 10.1 of the Partnership's Registration Statement on Form S-3/A filed on July 8, 2002).
10.4	First Amendment to Contribution Agreement (incorporated by reference to Exhibit 10.8 of the Partnership's Registration Statement on Form S-3/A filed on September 24, 2002).
10.5	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on October 31, 2002).
10.6	Delegation of Control Agreement (incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.7	First Amending Agreement to the Delegation of Control Agreement dated as of February 21, 2005 (incorporated by reference to Exhibit 10.1 of the Partnership's Quarterly Report on Form 10-Q filed on May 5, 2005).
10.8	Amended and Restated Treasury Services Agreement (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.9	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.10	General and Administrative Services Agreement (incorporated by reference to Exhibit 10.5 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.11	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).

Exhibit Number	Description
10.12	Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference of Exhibit 10.11 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.13	First Amendment, dated January 12, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Quarterly Report on Form 10-Q filed on May 4, 2004).
10.14	Second Amendment, dated April 26, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q filed on May 4, 2004).
10.15	Third Amendment to the Amended and Restated Credit Agreement, dated as of January 24, 2003 (as amended by the First Amendment, dated January 12, 2004 and the Second Amendment, dated as of April 26, 2004), by and the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed on April 19, 2005).
10.16	Fourth Amendment to the Amended and Restated Credit Agreement, dated January 24, 2003 (as amended by the First Amendment, dated January 12, 2004, the Second Amendment, dated April 26, 2004, and the Third Amendment dated April 14, 2005), by and among the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed on September 21, 2005).
10.17	Commercial Paper Dealer Agreement between the Company, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.18	Commercial Paper Dealer Agreement between the Company, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.19	Commercial Paper Dealer Agreement between the Company, as Issuer, and Goldman, Sachs & Co., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.3 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.20	Commercial Paper Dealer Agreement between the Company, as Issuer, and Merrill Lynch Money Markets Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.4 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.21	Issuing and Paying Agency Agreement between the Company and Deutsche Bank Trust Company Americas, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.5 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.22	Amended and Restated 364-Day Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.12 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.23	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.13 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).

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

Exhibit Number	Description
10.38[*+]	Executive Employment Agreement, dated April 14, 2003, between J. Richard Bird, as Executive, and Enbridge Inc., as Corporation.
10.39[+]	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.40	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.41	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.42	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.43	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on January 9, 2004).
10.44	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.45	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.46	Sixth Supplemental Indenture dated December 21, 2006 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 21, 2006).
10.47	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on February 10, 2005).
10.48	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on November 17, 2005).
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Partnership's Annual Report on Form 10-K filed on March 12, 2004).
21.1[*]	Subsidiaries of the Registrant.
23.1[*]	Consent of PricewaterhouseCoopers LLP.
31.1[*]	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2[*]	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1[*]	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2[*]	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. (incorporated by reference to Exhibit 99.1 of the Partnership's Annual Report on Form 10-K filed February 25, 2005).

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

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

ENBRIDGE ENERGY PARTNERS, L.P.

FINANCIAL STATEMENT SCHEDULES

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

Report of Independent Registered Public Accounting Firm

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

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

Consolidated financial statements

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

Internal control over financial reporting

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

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

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

PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2007

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

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

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

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

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

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

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

General

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

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

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

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

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

Enbridge Energy Management, L.L.C.

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

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

Enbridge Inc.

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

Business Segments

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

Liquids

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

Natural Gas

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

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

Marketing

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

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

Principles of Consolidation

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

Accounting for Regulated Operations

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

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

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

Liquids

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

Natural Gas

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

Fee-Based Arrangements:

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

Other Arrangements:

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

These other types of arrangements are categorized as follows:

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Percentage-of-Proceeds Contracts—Under the terms of these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we then sell at market prices and retain as our fee.

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs and condensate extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGL and condensate.

- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw gas at the wellhead, we also sell for our own account at market prices, the resulting residue gas. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with an energy content equivalent to the original raw gas we received as measured in British thermal units, or Btu.

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

Marketing

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

Estimation of Revenue and Cost of Natural Gas

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

Cash and Cash Equivalents

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

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. As such, included in Accounts payable and other on our Consolidated Statements of Financial Position are obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $46.9 million and $46.5 million at December 31, 2006 and 2005, respectively.

Allowance for Doubtful Accounts

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

Inventory

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

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

Oil Measurement Gains and Losses

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

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

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

Operational Balancing Agreements and Natural Gas Imbalances

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

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

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

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

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

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

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

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

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

Goodwill

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

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

Intangibles, Net

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

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

Other Assets

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

Income Taxes

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

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

Derivative Financial Instruments

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

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

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

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

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

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

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

Commitments, Contingencies and Environmental Liabilities

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

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

Asset Retirement Obligations

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

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

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

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

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

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

Comparative Amounts

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

Recent Accounting Pronouncements Not Yet Adopted

Fair Value Measurements

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

Accounting for Registration Payment Arrangements

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

Staff Accounting Bulletin No. 108

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

3. ACQUISITIONS AND DISPOSITIONS

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

2006 Acquisitions and Dispositions

Oakhill Acquisition

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

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

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

2005 Acquisitions and Dispositions

North Texas Natural Gas System

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

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

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

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

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

Other 2005 Acquisitions

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

Sale of Gathering and Processing Assets

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

2004 Acquisitions

Mid-Continent System

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

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

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

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

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

Other 2004 Acquisitions

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

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

4. NET INCOME PER LIMITED PARTNER UNIT

We compute net income per limited partner unit by dividing net income, after deducting our allocation to the General Partner, by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. We have no dilutive securities, therefore basic and diluted earnings per unit amounts are equal. Net income per limited partner unit was determined as follows:

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

5. INVENTORY

Inventory is comprised of the following:

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

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

6. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

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

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

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

7. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2006 and 2005 are as follows:

	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Balance as of December 31, 2004	$—	$236.8	$20.4	$—	$257.2
Purchase price adjustments	—	1.0	—	—	1.0
Balance as of December 31, 2005	—	237.8	20.4	—	258.2
Acquisition	—	7.5	—	—	7.5
Balance as of December 31, 2006	$—	$245.3	$20.4	$—	$265.7

We completed our annual goodwill impairment test using data at June 30, 2006. To estimate the fair value of our reporting units we made 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 the long-range plans we use to manage our businesses. Based on the results of our impairment analysis, we determined that the fair value of each reporting unit exceeded its respective carrying amount, including goodwill. As a result, no goodwill impairment existed in any of our reporting units. We have not observed any events or circumstances subsequent to our analysis that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2006.

8. INTANGIBLES

The following table provides the gross carrying value, accumulated amortization and activity affecting these balances for each of our major classes of intangible assets.

	Gross Carrying Amount			Accumulated Amortization			
	Customer Contracts	Natural Gas Supply Opportunities	Intangible Assets Gross	Customer Contracts (in millions)	Natural Gas Supply Opportunities	Accumulated Amortization Gross	Intangible Assets, Net
Balance at December 31, 2003	$31.1	$48.1	$ 79.2	$(2.0)	$ —	$ (2.0)	$77.2
Amortization	—	—	—	(1.3)	(1.9)	(3.2)	(3.2)
Balance at December 31, 2004	31.1	48.1	79.2	(3.3)	(1.9)	(5.2)	74.0
Acquisitions	14.3	—	14.3	—	—	—	14.3
Dispositions	(2.2)	—	(2.2)	0.3	—	0.3	(1.9)
Amortization	—	—	—	(1.7)	(2.0)	(3.7)	(3.7)
Balance at December 31, 2005	43.2	48.1	91.3	(4.7)	(3.9)	(8.6)	82.7
Acquisitions	12.8	—	12.8	—	—	—	12.8
Amortization	—	—	—	(2.2)	(1.9)	(4.1)	(4.1)
Balance at December 31, 2006	$56.0	$48.1	$104.1	$(6.9)	$(5.8)	$(12.7)	$91.4

Our customer contracts are comprised entirely of natural gas purchase and sale agreements associated with our Natural Gas and Marketing segments. We amortize our customer contracts on a straight-line basis over the weighted average useful life of the underlying reserves at the time of acquisition, which approximates 25 years.

We obtained the natural gas supply opportunities in conjunction with the 2003 North Texas system acquisition and relate entirely to our Natural Gas segment. The value of the intangible asset was determined by a third party appraisal and it represents the fair value associated with growth opportunities present in the Barnett Shale producing zone. We are amortizing the natural gas supply opportunities over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which approximates 25 years.

We estimate the amortization expense associated with our intangibles for each year through December 31, 2011 to approximate $4.2 million.

9. DEBT

The following table presents the primary components of our outstanding indebtedness and the weighted average interest rates associated with each component at the end of each period presented, before the effect of our interest rate hedging activities as discussed in Notes 14 and 15:

	December 31,				
		2006		2005	
	Maturity	Rate	Dollars	Rate	Dollars
		(dollars in millions)			
First Mortgage Notes	2011	9.15%	$ 155.0	9.15%	$ 186.0
Senior Notes	2009-2034	5.74%	1,498.4	5.70%	1,198.6
Credit Facility	2010	—	—	—	—
Commercial Paper[1]	2010	5.45%	443.7	4.36%	329.3
			$2,097.1		$1,713.9
Current maturities and short-term debt			(31.0)		(31.0)
Long-term debt			$2,066.1		$1,682.9

(1) Individual issuances of commercial paper generally mature in 90 days or less, but are supported by our credit facility and are therefore considered long-term debt.

First Mortgage Notes

The First Mortgage Notes ("Notes") are collateralized by a first mortgage lien on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. Property, plant and equipment, net, associated with the Lakehead Partnership was $1,495.1 million and $1,384.2 million at December 31, 2006 and 2005, respectively. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. We believe these restrictions will not negatively impact our ability to finance future expansion projects. Under the Notes agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (see Note 10) for the immediately preceding calendar quarter. We would be required to pay a redemption premium pursuant to the Note agreements should we elect to repay the Notes prior to their stated maturity.

Under the terms of the Notes, we are required to establish, at the end of each quarter, a debt service reserve. This reserve includes an amount equal to 50% of the prospective Notes interest payments for the immediately following quarter and an amount for Note sinking fund repayments. At December 31, 2006 and 2005, there was no required debt service reserve, as we have made all required interest and sinking fund payments.

Senior Notes

All of the Senior Notes pay interest semi-annually and have varying maturities and terms as outlined below. The Senior Notes do not contain any covenants restricting the issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. The interest rates set forth in this table represent the interest rates as set forth on the face of each note agreement without consideration to any discount or interest rate hedging activities.

Senior Notes	Interest Rate	December 31, 2006	December 31, 2005
		(in millions)	
Senior Notes maturing in 2009	4.000%	$ 200.0	$ 200.0
Senior Notes maturing in 2012	7.900%	100.0	100.0
Senior Notes maturing in 2013	4.750%	200.0	200.0
Senior Notes maturing in 2014	5.350%	200.0	200.0
Senior Notes maturing in 2016	5.875%	300.0	—
Senior Notes maturing in 2018	7.000%	100.0	100.0
Senior Notes maturing in 2028	7.125%	100.0	100.0
Senior Notes maturing in 2033	5.950%	200.0	200.0
Senior Notes maturing in 2034	6.300%	100.0	100.0
		1,500.0	1,200.0
Unamortized Discount		(1.6)	(1.4)
		$1,498.4	$1,198.6

Credit Facility

Our Credit Facility, as amended, is a five-year term facility that matures in April 2010. In March 2006, we increased the current borrowing capacity from $800 million to $1 billion. Additionally, our Credit Facility has a letter of credit sublimit of $300 million. We pay interest on the amounts outstanding at variable rates equal to the "Base Rate" or a "Eurodollar Rate" as defined in the Credit Facility. In the case of Eurodollar Rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under the facility. A facility fee is payable on the entire amount of the Credit Facility whether or not drawn. The facility fee also varies depending on our credit rating. Our Credit Facility contains restrictive covenants that require us to maintain a minimum interest coverage ratio of 2.75 and a maximum leverage ratio of 5.25 for twelve months through December 2006, at which time it decreases to 5.00, thereafter. At December 31, 2006, our interest coverage ratio was approximately 4.4 and our leverage ratio was approximately 4.6. Our Credit Facility also places limitations on the debt that our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary. At December 31, 2006 and 2005, we had no amounts outstanding under our Credit Facility and letters of credit totaling $59.3 million and $149.3, respectively. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2006, we could borrow $495.7 million under the terms of our Credit Facility.

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the amounts due. During the years ended December 31, 2005 and 2004, we net settled borrowings of approximately $565 million and $1,573 million, on a non-cash basis.

Commercial Paper Program

We have a commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. At December 31, 2006, our Credit Facility remains undrawn and available to support our commercial paper program. At December 31, 2006 and 2005, respectively, we had $443.7 and $329.3 million of commercial paper outstanding, net of unamortized discount of $1.3 million and $0.7 million, at a weighted average interest rate of 5.45% and 4.36% and outstanding letters of credit totaling $59.3 and $149.3 million. At December 31, 2006 and 2005, respectively, we could issue an additional $155 million and $270 million in principal amount under our commercial paper program.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis under our unsecured long-term Credit Facility. Accordingly, such amounts have been classified as long-term debt in our accompanying Consolidated Statement of Financial Position.

Interest

For the years ended December 31, 2006, 2005, and 2004, interest expense is net of amounts capitalized of $10.7 million, $4.0 million, and $2.1 million. For each of the years ended December 31, 2006, 2005, and 2004, we made interest payments totaling $109.7 million, $101.7 million, and $73.9 million.

Maturities of Third Party Debt

The scheduled maturities of outstanding third party debt, excluding the market value of interest rate swaps, at December 31, 2006, are summarized as follows:

	(in millions)
2007	$ 31.0
2008	31.0
2009	231.0
2010	476.0
2011	31.0
Thereafter	1,300.0
Total	$2,100.0

10. PARTNERS' CAPITAL

Our capital accounts are comprised of a two percent general partner interest and 98 percent limited partner interests. The limited partner interests are comprised of Class A common units, Class B common units, Class C units, and i-units. The limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. The General Partner manages our operations, subject to a delegation of control agreement with Enbridge Management, and participates in the Partnership's distributions, including certain incentive income distributions.

Class A common units

The following table presents the net proceeds from our Class A common unit issuances for each of the years ended December 31, 2006, 2005 and 2004. The proceeds from each of our offerings were generally used to repay amounts outstanding under our credit facilities or issuances of commercial paper, which we initially borrowed to finance our capital expansion projects and acquisitions, or to repay other outstanding obligations.

Issuance Date	Number of Class A Common units Issue	Offering Price per Class A Common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except per unit amounts)			
2006					
We did not issue any Class A common units during 2006.					
2005					
December 2005	136,200	$46.000	$ 6.0	$0.2	$ 6.2
November 2005	3,000,000	$46.000	132.1	2.8	134.9
February 2005	2,506,500	$49.875	124.8	2.7	127.5
2005 Totals	5,642,700		$262.9	$5.7	$268.6
2004					
September 2004	3,680,000	$47.900	$168.6	$3.6	$172.2
January 2004	450,000	$50.300	21.6	0.4	22.0
2004 Totals	4,130,000		$190.2	$4.0	$194.2

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Class B common units

Our outstanding Class B common units are held entirely by our general partner and have rights similar to our Class A common units except that they are not currently eligible for trading on the NYSE.

Class C units

In August 2006, we issued and sold 5.4 million Class C units, representing a new class of limited partner interest, to our general partner and 5.4 million Class C units to an institutional investor for a purchase price of $46.00 per unit in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933. We received proceeds of approximately $500 million, net of expenses associated with the private placement. Additionally, our general partner contributed approximately $10 million to maintain its two percent general partner interest.

i-units

The i-units are a separate class of our limited partner interests, all of which are owned by Enbridge Management and are not publicly traded.

Enbridge Management, as the owner of our i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

- Any proposed action that would cause us to be treated as a corporation for U.S. federal income tax purposes;

- Amendments to our partnership agreement that would have a material adverse effect on the holder of our i-units, unless, under our partnership agreement, the amendment could be made by our general partner without a vote of holders of any class of units;
- The removal of our general partner and the election of a successor general partner; and
- The transfer by our general partner of its general partner interest to a non-affiliated person that requires a vote of holders of units under our partnership agreement and the admission of that person as a general partner.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management's shares vote or refrain from voting their shares. Furthermore, under the terms of our partnership agreement, we agree that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

Distributions

Our partnership agreement requires us to distribute 100 percent of our "Available Cash", which is generally defined in our partnership agreement as the sum of all cash receipts and net additions to reserves for future cash requirements less cash disbursements and amounts retained by us. Enbridge Management, as delegate of our general partner under the delegation of control agreement, computes the amount of our "Available Cash." Typically, the General Partner and owners of our common units will receive distributions in cash. However, we also retain reserves to provide for the proper conduct of our business and as necessary to comply with the terms of our agreements or obligations (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). We make distributions to our partners approximately 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

Our general partner is granted discretion by our partnership agreement, which discretion has been delegated to Enbridge Management, subject to the approval of the General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions of our Available Cash are generally made 98.0 percent to holders of our limited partner units and 2.0 percent to our general partner. However, distributions are subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of distributions to the unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15.0 percent, 25.0 percent and 50.0 percent of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per limited partner units. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead, will distribute additional i-units such that the cash is retained and used in our business. Similarly, until August 15, 2009, we will distribute additional Class C units to the holders of our Class C units in lieu of cash distributions, which will be retained and used in our business. Further, we retain an additional amount equal to 2.0 percent of the i-unit and Class C unit distributions from the General Partner to maintain its 2 percent general partner interest in us.

Enbridge Management, as owner of the i-units, does not receive distributions in cash. Instead, each time that the we make a cash distribution to the General Partner and the holders of our common units, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's shares and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common 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 quarterly cash distribution of $0.59 per common unit.

The following table sets forth our distributions, as approved by the board of directors for each period in the years ended December 31, 2006, 2005 and 2004.

Distribution Declaration Date	Distribution Payment Date	Record Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[1]	Amount of Distribution of Class C units to Class C unit Holders[2]	Retained from General Partner[3]	Distribution of Cash
			(in millions, except per unit amounts)					
2006								
October 27	November 14	November 6	$0.925	$ 79.6	$11.5	$10.1	$0.4	$ 57.6
July 28	August 14	August 4	0.925	68.1	11.3	—	0.2	56.6
April 27	May 15	May 5	0.925	67.8	11.0	—	0.2	56.6
January 30	February 14	February 7	0.925	67.6	10.8	—	0.2	56.6
				$283.1	$44.6	$10.1	$1.0	$227.4
2005								
October 26	November 14	November 3	$0.925	$ 64.1	$10.6	$ —	$0.2	$ 53.3
July 28	August 12	August 5	0.925	64.0	10.5	—	0.2	53.3
April 25	May 13	May 4	0.925	63.8	10.3	—	0.2	53.3
January 24	February 14	February 3	0.925	61.0	10.1	—	0.2	50.7
				$252.9	$41.5	$ —	$0.8	$210.6
2004								
October 22	November 12	November 1	$0.925	$ 60.7	$ 9.9	$ —	$0.2	$ 50.6
July 22	August 13	August 2	0.925	56.6	9.6	—	0.2	46.8
April 26	May 14	May 5	0.925	56.5	9.5	—	0.2	46.8
January 22	February 13	February 2	0.925	56.3	9.3	—	0.2	46.8
				$230.1	$38.3	$ —	$0.8	$191.0

(1) We issued 969,200, 802,539 and 840,239 i-units to Enbridge Energy Management, L.L.C., the sole owner of our i-units, during 2006, 2005 and 2004, respectively, in lieu of cash distributions.

(2) We issued 200,587 additional Class C units to our Class C unitholders in lieu of cash distributions during 2006, including 100,293 to our general partner.

(3) We retained an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner to maintain its 2 percent general partner interest in us.

11. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management and administrative, operations and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the services charged to us.

The portion of direct workforce costs associated with the management and administrative services provided at our Houston office and the operating and administrative services provided to support our facilities across the United States, are charged to us by Enbridge and its affiliates.

Certain of the operating activities associated with our Liquids segment are provided by Enbridge Pipelines Inc. ("Enbridge Pipelines"), a subsidiary of Enbridge, as the majority of these pipeline systems form one contiguous system with the Enbridge system in Canada. These services include control center operations, facilities management, shipper services, pipeline integrity management and other related activities. The costs to provide these services are allocated to us from Enbridge Pipelines, based on an appropriate allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent and miles of pipe. We also receive costs associated with control center services for some of the natural gas assets from another affiliate of Enbridge.

Enbridge also allocates management and administrative costs to us pursuant to our partnership agreement and related services agreements. These costs are allocated to us based on an allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent, number of full-time equivalent employees and capital employed.

During 2006, 2005 and 2004, we incurred the following costs related to these services, which are included in operating and administrative expenses.

	Year ended December 31,		
	2006	2005	2004
		(in millions)	
Direct workforce costs	$163.9	$117.0	$101.7
Liquids /Natural Gas operating costs	17.3	15.3	14.0
Allocated management and administrative costs, including insurance	27.4	20.1	17.2
	$208.6	$152.4	$132.9

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. Included in our results for the twelve months ending December 31, 2006, 2005 and 2004, are operating revenues of $42.8 million, $43.6 million, and $23.6 million, respectively, related to these transactions.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Included in our results for the twelve months ending December 31, 2006, 2005 and 2004, are cost of natural gas expenses of $11.5 million, $4.5 million and $6.9 million, respectively, relating to these purchases.

Affiliate Notes

We have a loan payable to an affiliate of Enbridge that totaled $136.2 million and $151.8 million at December 31, 2006 and 2005, which matures in December 2007. The interest rate is 6.60% as of December 31, 2006 and 2005.

We incurred interest expense on the affiliate loan payable totaling $9.4 million, $9.7 million, and $9.0 million for the years ended December 31, 2006, 2005 and 2004, respectively. We added the interest expense incurred on the affiliate loan payable to the principal amount of the loan for the specified amounts in each of the respective periods. Additionally, in 2006 we repaid approximately $20.0 million in principal amount of this note.

General Partner Distributions

Our general partner owns an effective 2 percent general partner ownership interest in us. Pursuant to our partnership agreement we paid cash distributions to our general partner of $28.1 million, $25.3 million, and $22.9 million for the years ended December 31, 2006, 2005 and 2004, respectively. The cash distributions we make to our general partner exclude an amount equal to 2 percent of the i-unit and Class C unit distributions, which we retain from the General Partner to maintain its 2 percent ownership interest in us.

As of December 31, 2006 and 2005, the General Partner also owned 3,912,750 Class B common units, representing 4.9 and 5.8 percent limited partner interest in us. We paid the General Partner cash distributions of $14.5 million, $14.5 million and $14.4 million related to its ownership of Class B common units for the years ended December 31, 2006, 2005 and 2004, respectively.

In August 2006, our general partner purchased approximately 5.4 million of our Class C units for $250 million, or $46.00 per unit. At December 31, 2006, the General Partner owned 5,535,076 of our Class C units, including 100,293 Class C units that we distributed in lieu of making cash distributions. The Class C units owned by our general partner represent an approximate 7.0 percent limited partner interest in us. Refer to Note 10 for additional information regarding the Class C units.

Conflicts of Interest

Enbridge Management makes all decisions relating to the management and control of our business through a delegation of control agreement with the General Partner and us. The General Partner owns the voting shares of Enbridge Management and elects all of Enbridge Management's directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines, owns all the common stock of the General Partner. Some of the General Partner's directors and officers are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of our unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, the General Partner, Enbridge and us. Our partnership agreement and the delegation of control agreement contain provisions that allow Enbridge Management to take into account the interest of all parties in addition to those of our unitholders in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

Enbridge Management

Pursuant to the delegation of control agreement between Enbridge Management, our General Partner and us, and our partnership agreement, we pay all expenses relating to Enbridge Management. This includes Texas franchise taxes and any other similar capital-based foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

12. ENVIRONMENTAL LIABILITIES

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, the General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date, no material environmental risks have been identified.

In connection with our acquisition of the Midcoast systems in October 2002, the General Partner has agreed to indemnify us and other related persons for certain environmental liabilities of which the General Partner has knowledge and which it did not disclose. The General Partner will not be required to indemnify us until the aggregate liabilities, including environmental liabilities, exceed \$20.0 million, and the General Partner's aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, \$150.0 million. We will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed.

As of December 31, 2006 and 2005, we have recorded \$4.1 million and \$4.0 million in current liabilities and \$3.3 million and \$4.8 million, respectively, in long-term liabilities primarily to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

In March 2004, we reduced our long-term environmental liabilities by approximately \$2.0 million related to certain of our Natural Gas assets. Since October 2002, during the time that these assets have been owned by us, we completed a review of the affected sites and determined that suspected contamination is less significant than originally estimated. Our assessment was based upon information gathered during the ownership period, existing technology, presently enacted laws and regulations and prior experience in remediating contaminated sites for similar assets.

13. COMMITMENTS AND CONTINGENCIES

Oil and Gas in Custody

Our Liquids assets transport crude oil and NGLs owned by our customers for a fee. The volume of liquid hydrocarbons in our pipeline systems at any one time varies from approximately 24 to 28 million barrels, virtually all of which is owned by our customers. Under the terms of our tariffs, losses of crude oil from identifiable incidents not resulting from our direct negligence may be apportioned among our customers. In addition, we maintain adequate property insurance coverage with respect to crude oil and NGLs in our custody.

Approximately 50% of the natural gas volumes on our natural gas assets are transported for customers on a contractual basis. We purchase the remaining 50% and sell to third-parties downstream of the purchase point. At any point in time, the value of our customers' natural gas in the custody of our natural gas systems is not material to us.

Rate Refunds

On October 8, 2004, the FERC issued an Order on Remand ("Remand Order") relating to initial rates on our Kansas Pipeline System ("KPC") for the period of time between December 1997 and November 2002. We acquired KPC on October 17, 2002. The Remand Order was issued in response to a United States Court of Appeals ruling in August 2003 requiring the FERC to address the issue of appropriate rate refunds, if any, with respect to KPC's initial rates. In the Remand Order, the FERC found that the proper initial rates are lower than the rates previously charged to customers pending resolution of this contested rate case. In accordance with the FERC's findings, any difference between what was collected and the revised initial Section 7 rates for the period of time between December 1997 and November 2002, plus interest compounded quarterly, is subject to refund.

Refunds to our customers were made in January 2005 pursuant to a refund plan agreed upon with customers and approved by the FERC. Our Consolidated Statement of Income for the year ended December 31, 2004, includes a charge of approximately \$13.6 million for the rate refunds and interest. The rate refunds relate almost entirely to a time period prior to our ownership of KPC.

Right-of-Way

As part of our pipeline construction process, we must obtain certain right-of-way agreements from landowners whose property the pipeline will cross. Right-of-way agreements that we buy are capitalized as part of Property, plant and equipment. Right-of-way agreements that are leased from a third-party are expensed. We recorded expenses of $2.1 million, $1.9 million, and $1.8 million for the leased right-of-way agreements for the years ended December 31, 2006, 2005, and 2004, respectively.

Legal Proceedings

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

Future Minimum Commitments

As of December 31, 2006, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

Future Minimum Commitments	2007	2008	2009	2010 (in millions)	2011	Thereafter	Total
Purchase commitments[1]	$451.8	$ —	$ —	$ —	$ —	$ —	$451.8
Power commitments[2]	3.2	—	—	—	—	—	3.2
Other operating leases	10.8	9.1	6.9	1.9	0.1	—	28.8
Right-of-way[3]	1.7	1.7	1.7	1.7	1.7	42.4	50.9
Product purchase obligations[4]	32.1	34.0	31.5	27.6	24.6	83.4	233.2
Service contract obligations[5]	16.4	15.6	12.5	8.3	6.2	1.8	60.8
Total	$516.0	$60.4	$52.6	$39.5	$32.6	$127.6	$828.7

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

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

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

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

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

14. FINANCIAL INSTRUMENTS

Fair Value of Debt Obligations

The table below presents the carrying amount and approximate fair values of our debt obligations. The carrying amounts of our commercial paper obligations approximate their fair values at December 31, 2006, due to the short-term nature of these obligations. The fair values of the First Mortgage Notes and Senior notes have been determined based on quoted market prices for the same or similar issues.

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial paper	$443.7	$443.7	$329.3	$329.3
Credit Facility	—	—	—	—
9.150% First Mortgage Notes	155.0	169.5	186.0	207.9
4.000% Senior notes due 2009	200.0	194.2	199.9	193.0
7.900% Senior notes due 2012	99.9	110.5	99.9	113.8
4.750% Senior notes due 2013	199.8	188.6	199.8	190.8
5.350% Senior notes due 2014	199.9	193.0	199.9	196.7
5.875% Senior notes due 2016	299.7	297.4	—	—
7.000% Senior notes due 2018	99.8	107.9	99.8	111.4
7.125% Senior notes due 2028	99.8	108.9	99.8	113.0
5.950% Senior notes due 2033	199.7	186.2	199.7	193.1
6.300% Senior notes due 2034	99.8	97.1	99.8	100.8

Fair Value of Derivative Financial Instruments

The fair values of our derivative financial instruments are determined based on available market information, valuation and modeling techniques. These modeling techniques require us to make estimates of future prices, price correlation, market volatility and liquidity. The estimates also reflect factors for time value of money and the volatility of prices underlying the contracts, the potential impact of liquidating positions in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of counterparties and operational risk.

Interest Rate Derivatives

We enter into interest rate swaps, collars and derivative financial instruments with similar characteristics to manage the effect of future interest rate movements on our interest costs. The following table provides information about our current interest rate derivatives by transaction type for the specified periods.

	Notional Principal	Partnership Pays	Partnership Receives	Maturity Date	Fair Value December 31, 2006 (dollars in millions)	Fair Value December 31, 2005 (dollars in millions)
Interest Rate Swaps						
Floating to Fixed:						
	$ 30.0	3.180%	LIBOR [2]	January 18, 2006	$ —	$0.1
	$ 30.0	3.180%	LIBOR	January 20, 2006	—	0.1
	$ 30.0	3.200%	LIBOR	January 27, 2006	—	0.1
	$ 30.0	3.220%	LIBOR	January 30, 2006	—	0.1
	$ 30.0	3.210%	LIBOR	February 3, 2006	—	0.1
	$ 50.0	4.715%	LIBOR	January 22, 2007	0.1	—
	$ 50.0	4.738%	LIBOR	January 24, 2007	0.1	—
	$ 50.0	4.740%	LIBOR	February 3, 2007	0.1	—
	$ 50.0	4.750%	LIBOR	February 8, 2007	0.1	—
	$ 50.0	5.158%	LIBOR	April 3, 2007	0.1	—
	$ 50.0	5.163%	LIBOR	April 10, 2007	—	—
	$ 50.0	5.165%	LIBOR	April 17, 2007	—	—
	$ 50.0	5.175%	LIBOR	April 25, 2007	—	—
	$ 50.0	4.370%	LIBOR	June 1, 2013	1.5	1.0
	$ 50.0	4.343%	LIBOR	June 1, 2013	1.6	1.1
	$ 25.0	4.310%	LIBOR	June 1, 2013	0.7	0.5
Fixed to Floating:						
	$ 50.0	LIBOR-21bps[1]	4.750%	June 1, 2013	(0.5)	0.2
	$ 50.0	LIBOR-21bps[1]	4.750%	June 1, 2013	(0.5)	0.2
	$ 25.0	LIBOR-25bps[1]	4.750%	June 1, 2013	(0.3)	0.2
Treasury Locks:						
	$100.0	4.697%	30Yr UST [3]	December 17, 2007	1.2	—
	$100.0	4.668%	30Yr UST	December 17, 2007	1.6	—
Interest Rate Collars:						
Calls	$ 50.0	5.500%	LIBOR	June 13, 2008	0.1	—
Puts	$ 50.0	4.199%	LIBOR	June 13, 2008	—	—
Calls	$ 50.0	5.500%	LIBOR	June 25, 2008	—	—
Puts	$ 50.0	4.149%	LIBOR	June 25, 2008	—	—

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

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

(3) 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 are 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 Accumulated other comprehensive income.

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 Derivatives

The following table provides summarized information about the fair values of our outstanding commodity derivative financial instruments at December 31, 2006 and 2005:

	December 31, 2006					December 31, 2005	
		Wtd Avg Price		Fair Value[3]		Fair Value[3]	
	Notional	Receive	Pay	Asset	Liability	Asset	Liability
Swaps							
Natural gas[1]							
Receive variable/ pay fixed	92,254,562	$ 6.70	$ 7.44	$ 25.6	$ (94.2)	$511.0	$ (12.7)
Receive fixed/ pay variable	123,886,005	6.37	7.13	84.3	(160.7)	15.1	(790.4)
Receive variable/ pay variable	85,845,702	7.36	7.32	7.9	(4.8)	8.0	(5.3)
NGL[2]							
Receive variable/ pay fixed	99,645	38.52	43.65	—	(0.5)	—	—
Receive fixed/ pay variable	8,335,133	37.91	39.98	18.3	(34.4)	—	(60.3)
Crude[2]							
Receive fixed/ pay variable	1,386,571	52.21	66.34	0.2	(18.5)	0.2	(22.0)
Options—calls							
Natural gas[1]	1,826,000	7.47	4.31	—	(5.4)	—	(9.5)
Options—puts							
Natural gas[1]	2,890,000	7.19	4.67	1.0	—	0.1	—
Totals[4]				$137.3	$(318.5)	$534.4	$(900.2)

(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").

(3) Fair values of derivatives are presented in millions of dollars.

(4) We record the fair value of our derivative financial instruments in the balance sheet as current and long-term assets or liabilities on a net basis by counterparty.

15. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations 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 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. 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 and 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 or commodity prices.

Accounting Treatment

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

Derivativefair 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 these Consolidated Financial Statements, 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.

16. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following table presents certain financial information relating to our business segments as of and for the years ended December 31, 2006, 2005 and 2004.

	As of and for the Year Ended December 31, 2006				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 512.8	$5,404.1	$3,182.3	$ —	$9,099.2
Less: Intersegment revenue	—	2,383.4	206.8	—	2,590.2
Operating revenue	512.8	3,020.7	2,975.5	—	6,509.0
Cost of natural gas	—	2,601.1	2,913.5	—	5,514.6
Operating and administrative	141.3	215.4	5.4	2.7	364.8
Power	107.6	—	—	—	107.6
Depreciation and amortization	64.1	70.3	0.5	0.2	135.1
Gain on sale of assets	—	—	—	—	—
Operating income	199.8	133.9	56.1	(2.9)	386.9
Interest expense	—	—	—	(110.5)	(110.5)
Rate Refunds	—	—	—	—	—
Other income	—	—	—	8.5	8.5
Net income	$ 199.8	$ 133.9	$ 56.1	$(104.9)	$ 284.9
Total assets	$1,816.4	$2,797.3	$ 366.9	$ 243.2	$5,223.8
Capital expenditures (excluding acquisitions)	$ 237.2	$ 614.8	$ 1.9	$ 10.5	$ 864.4

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

	As of and for the Year Ended December 31, 2005				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 418.0	$4,945.1	$3,884.2	$ —	$9,247.3
Less: Intersegment revenue	—	2,593.0	177.4	—	2,770.4
Operating revenue	418.0	2,352.1	3,706.8	—	6,476.9
Cost of natural gas	—	2,018.7	3,744.6	—	5,763.3
Operating and administrative	144.2	175.0	4.1	3.5	326.8
Power	74.8	—	—	—	74.8
Depreciation and amortization	71.7	66.0	0.5	—	138.2
Gain on sale of assets	—	(18.1)	—	—	(18.1)
Operating income	127.3	110.5	(42.4)	(3.5)	191.9
Interest expense	—	—	—	(107.7)	(107.7)
Rate refunds	—	—	—	—	—
Other income	—	—	—	5.0	5.0
Net income	$ 127.3	$ 110.5	$ (42.4)	$(106.2)	$ 89.2
Total assets	$1,664.0	$2,145.9	$ 512.3	$ 106.2	$4,428.4
Capital expenditures (excluding acquisitions)	$ 77.0	$ 263.8	$ 0.2	$ 3.8	$ 344.8

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

	As of and for the Year Ended December 31, 2004				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 409.3	$2,890.1	$2,686.9	$ —	$5,986.3
Less: Intersegment revenue	—	1,570.2	124.4	—	1,694.6
Operating revenue	409.3	1,319.9	2,562.5	—	4,291.7
Cost of natural gas	—	1,031.8	2,555.3	—	3,587.1
Operating and administrative	128.9	138.3	3.4	3.5	274.1
Power	72.8	—	—	—	72.8
Depreciation and amortization	68.5	51.7	0.2	0.1	120.5
Gain on sale of assets	—	—	—	—	—
Operating income	139.1	98.1	3.6	(3.6)	237.2
Interest expense	—	—	—	(88.4)	(88.4)
Rate refunds	—	—	—	(13.6)	(13.6)
Other income	—	—	—	3.0	3.0
Net income	$ 139.1	$ 98.1	$ 3.6	$(102.6)	$ 138.2
Total assets	$1,639.8	$1,717.2	$ 313.7	$ 100.0	$3,770.7
Capital expenditures (excluding acquisitions)	$ 81.9	$ 197.4	$ 0.3	$ 9.2	$ 288.8

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

17. SUBSEQUENT EVENTS

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.

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 through-put. We have the potential of incurring additional expenditures to remediate any condition on the line that is determined to have caused the rupture.

In February 2007, a contractor undertaking work in Rusk County, Wisconsin on the Enbridge Southern Lights project punctured the adjacent Line 14 pipeline, resulting in a release of crude oil estimated at 3,000 barrels. As the spill was largely contained within the ditch used for construction, environmental impact was minimized. Impact to customers was 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.

18. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
	(in millions, except per unit amounts)				
2006 Quarters					
Operating revenue	$1,888.6	$1,424.7	$1,532.3	$1,663.4	$6,509.0
Operating income[2]	$ 108.0	$ 93.6	$ 108.7	$ 76.6	$ 386.9
Net income[2]	$ 81.1	$ 70.4	$ 82.2	$ 51.2	$ 284.9
Net income per limited partner unit[1] [2]	$ 1.12	$ 0.96	$ 1.03	$ 0.56	$ 3.62
2005 Quarters					
Operating revenue	$1,250.1	$1,332.7	$1,809.6	$2,084.5	$6,476.9
Operating income	$ 53.2	$ 50.6	$ 11.9	$ 76.2	$ 191.9
Net income	$ 28.2	$ 25.7	$ (14.4)	$ 49.7	$ 89.2
Net income per limited partner unit[1]	$ 0.37	$ 0.32	$ (0.32)	$ 0.68	$ 1.06

(1) The General Partner's allocation of net income has been deducted before calculating net income per limited partner unit.

(2) The fourth quarter of 2006 includes approximately $8.3 million for raw natural gas purchases and transportation and fractionation charges that relate to prior years that we had not previously recorded.