
**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

(State or other jurisdiction of
incorporation or organization)

39-1715850

(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

Class A Common Units

Name of each exchange on which registered

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:

	<u>2006</u>
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.....	<u>2.0%</u>
	<u>100.0%</u>

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:

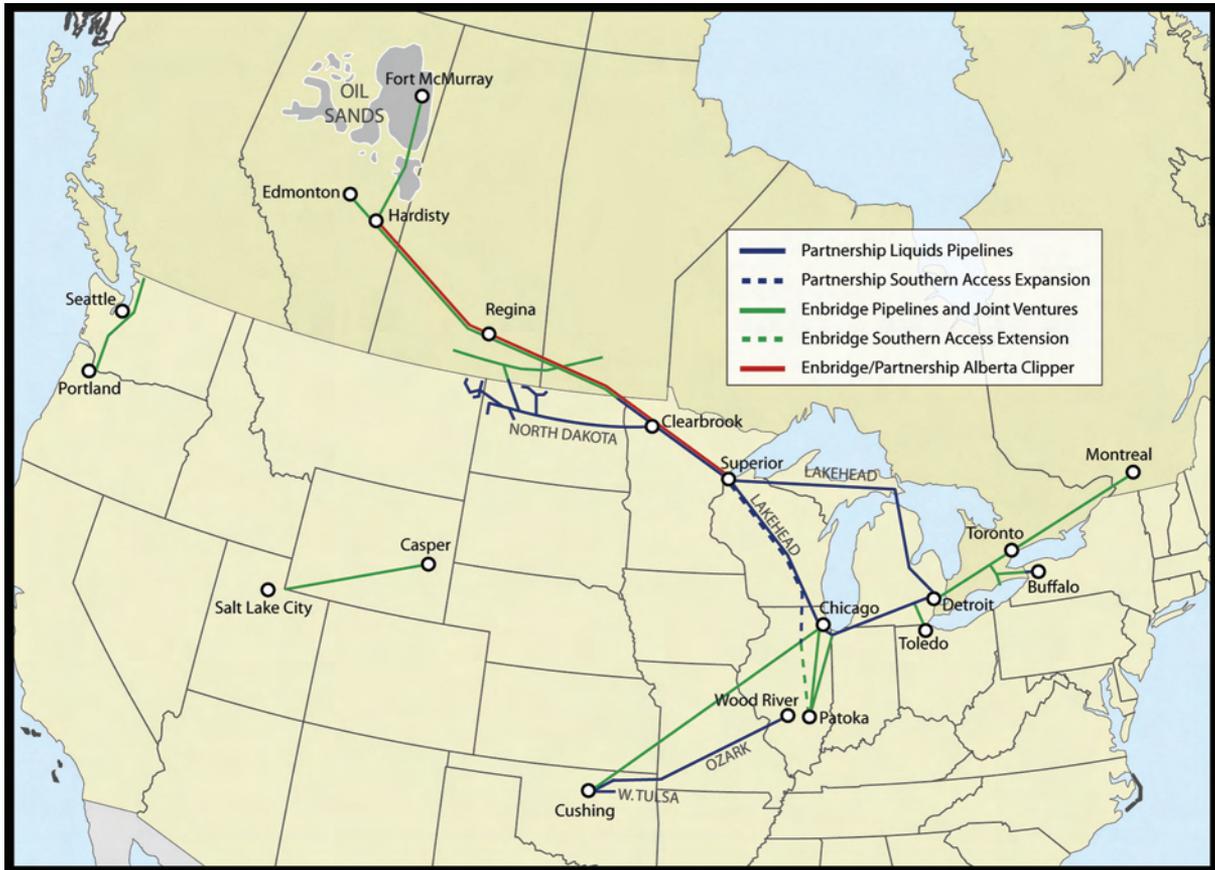
- Acquisition prices for the stable energy assets we seek have become inflated; and
- The expansion and diversification of our asset base over the past few years has created opportunities for internal growth projects that are expected to enhance the value of services we provide to our customers and returns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

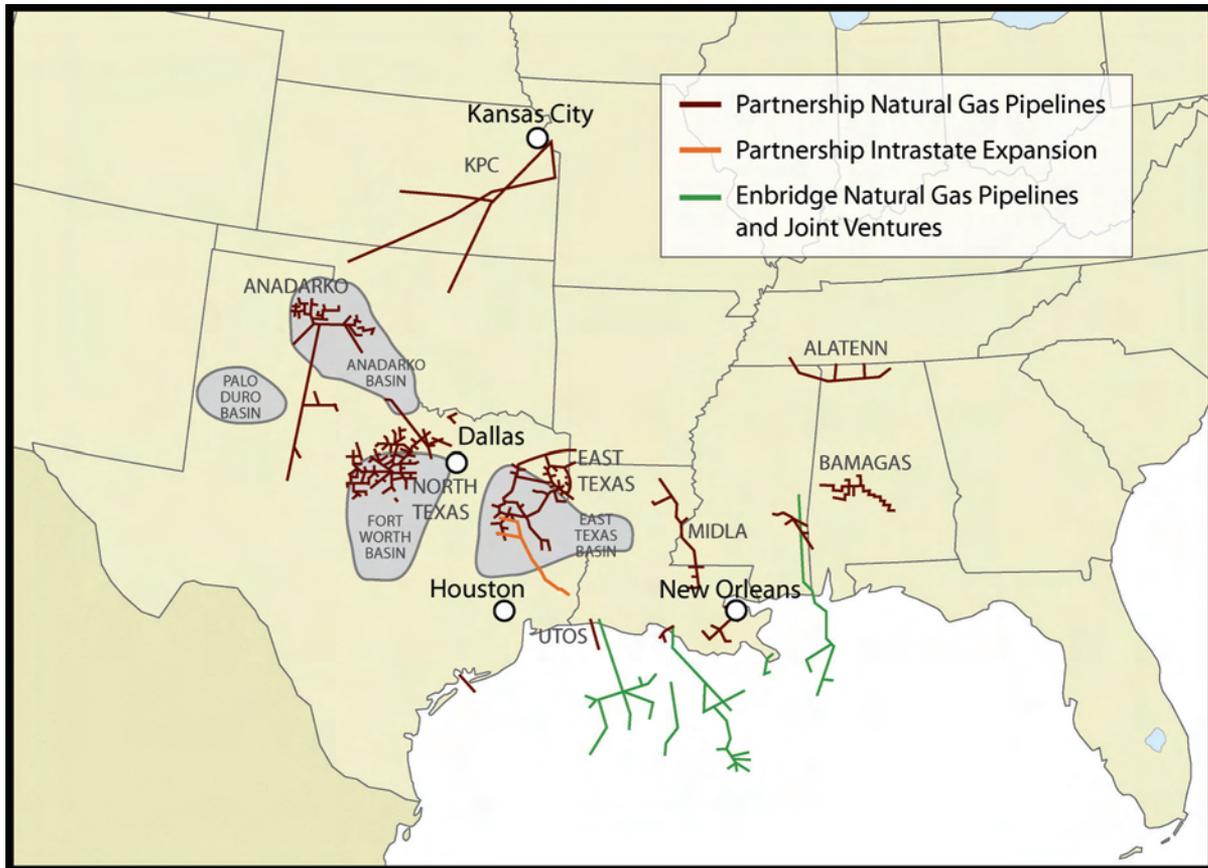
Our Southern Access project is the cornerstone of our mainline expansion initiatives to address the expected increase in supply of western Canadian crude oil. Our \$1.3 billion project will provide an additional 400,000 Bpd of heavy crude oil capacity to the Chicago market and beyond by early 2009, with 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 Joslyn 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.....	<u>1,204</u>	<u>1,036</u>	<u>1,064</u>	<u>1,003</u>	<u>937</u>
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	<u>313</u>	<u>303</u>	<u>358</u>	<u>351</u>	<u>365</u>
Total Deliveries	<u>1,517</u>	<u>1,339</u>	<u>1,422</u>	<u>1,354</u>	<u>1,302</u>
Barrel miles (billions per year)	<u>400</u>	<u>338</u>	<u>367</u>	<u>345</u>	<u>341</u>

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 partners.

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.

<u>Major System</u>	<u>Capacity MMcf/d</u>	<u>Percentage Reserved Under Contract as of December 31, 2006</u>
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 filing.

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 CO₂ plant, with 250 tons per day of capacity, takes excess CO₂ 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.

	<u>Published Tariff Per Barrel</u>
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 M³ 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 M³ 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:

	<u>Published Tariff Per Barrel</u>
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:

	<u>Published Tariff Per Barrel</u>
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.