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, 2004

OR

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

For the transition period from to

Commission File Number: 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.
(Exact name of Registrant as specified in its charter)

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

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

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

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

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

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

Indicate by check mark 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 an accelerated filer (as defined in Rule 12b-2 of the 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, 2004, was $1,880,527,004.

As of February 15, 2005, the Registrant has 46,802,634 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 "Items 1.—Business—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:

Act	Pipeline Safety Improvement Act
Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle, which were acquired on October 17, 2002
AOSP	Athabasca Oil Sands Project, located in northern Alberta, Canada
Bbl	Barrel of liquids (approximately 42 U.S. gallons)
Bpd	Barrels per day
CAA	Clean Air Act
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of the Lakehead system's customers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
Cdn.	Amount denominated in Canadian dollars
Cold Lake	Oil sands reserves in the province of Alberta, Canada
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.
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.
Enbridge U.S.	Enbridge (U.S.) Inc.
Energy Policy Act	Energy Policy Act of 1992
EES	Enbridge Employee Services, Inc.
EPA	Environmental Protection Agency
EPU	Earnings per unit
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Flint Hills	Flint Hills Resources, L.P., an affiliate of Koch
General Partner	Enbridge Energy Company, Inc., general partner of the Partnership
HCA	High consequence area

Hinshaw pipeline	An intrastate pipeline that receives natural gas in interstate commerce at or within the boundaries of the state and is ultimately consumed within that state
HLPSA	Hazardous Liquid Pipeline Safety Act
ICA	Interstate Commerce Act
Koch	Koch Pipelines Company, L.P., an unrelated company
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
Long ton	2,240 pounds
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 comprised of the Midcoast system, Northeast Texas system and South Texas system, acquired October 17, 2002
Mid-Continent system	Crude oil pipeline and storage facilities in Oklahoma to Illinois area and acquired on March 1, 2004
NEB	National Energy Board
NGA	Natural Gas Act
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act
North Dakota system	Liquids petroleum pipeline system in the Upper Midwest
Northeast Texas system	Natural gas gathering and processing assets acquired on October 17, 2002 and integrated with the East Texas system during 2004
North Texas system	Natural gas gathering and processing assets acquired on December 31, 2003
NYMEX	The New York Mercantile Commodity Exchange where natural gas futures, options contracts, and other energy futures are traded
NYSE	New York Stock Exchange
OBA	Operational balancing agreement
OCSLA	Outer Continental Shelf Lands Act
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety
OSHA	Occupational Safety and Health Administration
OTC	Over-the-Counter derivatives are privately negotiated contracts between two parties and are not limited to restrictions of contracts traded on exchanges

PADD	Petroleum Administration for Defense Districts
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
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership
Partnership	Enbridge Energy Partners, L.P. and subsidiaries
PPIFG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act
RCRA	Resource Conservation and Recovery Act
RSPA	Research and Special Programs Administration
SAGD	Steam Assisted Gravity Drainage; a process to extract crude oil from oil sands
SEC	Securities and Exchange Commission
SEP II	System Expansion Program II
Settlement Agreement	A FERC approved settlement agreement, signed October 1996
SFAS	Statement of Financial Accounting Standards
SFPP	Santa Fe Pacific Pipelines, L.P., an unrelated company
SPCC	Spill Prevention, Control and Countermeasure
Suncor	Suncor Energy Inc., an unrelated company
Syncrude	Syncrude Canada Ltd., an unrelated company
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
WCSB	Western Canadian Sedimentary Basin

PART I

Items 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, transmission 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 the 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 the General Partner.

At December 31, 2004, our ownership is comprised of a 2% general partner interest and a 98% limited partner interest. The General Partner owns the 2% general partner interest and a 6.5% limited partner interest, in the form of 3,912,750 Class B common units in the Partnership. The remaining 91.5% limited partner interest is represented by a 73.4% ownership interest of 44,296,134 publicly traded Class A common units and an 18.1% ownership interest of 10,902,409 i-units, which are wholly-owned by Enbridge Management.

The General Partner receives quarterly cash distributions from its limited partner interests. In addition, it also receives an incentive distribution from us for being our general partner. This incentive distribution is calculated in increments based on the amount by which quarterly distributions to unitholders exceed specified target levels as set forth in our Partnership Agreement. These incentive distributions can reach a maximum of 50% of all quarterly distributions to unitholders for target levels greater than $0.99 per Class A and B common units and i-units. Including both its general and limited partner interests in us, at the 2004 distribution level, the General Partner received approximately 19% of all quarterly distributions paid during 2004, of which 12% was attributable to its general partner interest and 7% was attributable to its limited partner interest.

Enbridge Management is a Delaware limited liability company that was formed on May 14, 2002. On October 17, 2002, Enbridge Management issued 7,450,000 Listed Shares to the public and 1,550,000 Listed Shares to the General Partner for cash. It used the net proceeds of the offering of approximately $330.8 million, based on the public offering price of $39.00 per share, to purchase 9,000,000 i-units from the Partnership, compensate Enbridge for agreeing to certain purchase provisions and a tax indemnification agreement and pay costs of the offering. Enbridge Management's shares represent limited liability company interests and are traded on the NYSE under the symbol "EEQ." Enbridge Management does not receive quarterly distributions of cash on these i-units from the Partnership; instead, the number of i-units owned by Enbridge Management increases automatically under the Partnership's partnership agreement. Enbridge Management's principal activity is managing the business and affairs of the Partnership and our subsidiaries. Under a Delegation of Control Agreement, the 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.

Beginning in 2001, we have diversified geographically and operationally through acquisitions of a crude oil gathering and transportation system and of natural gas gathering, treating, processing and transmission systems. These acquisitions materially increased the size and diversity of our business. On

March 1, 2004, we acquired our Mid-Continent system, which transports crude oil from the Cushing, Oklahoma hub to refineries in the U.S. Mid-continent region and further diversifies our Liquids segment. We are also actively pursuing a number of core-system expansion projects that relate to assets previously acquired. Since our initial public offering in 1991, we have increased our quarterly cash distribution by 57%, from $0.59 per unit to the current quarterly rate of $0.925 per unit.

AVAILABLE INFORMATION

We file annual, quarterly and other reports, and any amendments to those reports, and information with the SEC under the Exchange Act. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including ours.

We also makes available free of charge on or through our Internet website *http://www.enbridgepartners.com* our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act, as soon as reasonably practicable after we electronically files such material with the SEC.

BUSINESS STRATEGY

Our primary strategy is to grow cash distributions to our unitholders. To execute this strategy, we intend to:

- expand and increase the utilization of our pipeline systems' capacity to meet the supply of and demand for hydrocarbons in the markets they serve; and
- develop and acquire complementary energy delivery assets, particularly in the Gulf Coast region of the United States, and improve the financial performance and operating efficiency of assets we acquire.

We continue to analyze potential acquisitions, with a focus on crude oil and natural gas pipelines, storage terminals and related facilities. Major energy companies continue to dispose of their non-strategic assets, producing significant opportunities to grow our asset base through the acquisition of these mature energy infrastructure assets. We expect this trend to continue and believe we are well positioned to participate in these opportunities. We are continuing to seek out opportunities throughout the United States, particularly in the U.S. Gulf Coast area, where asset divestitures are anticipated in and around our existing natural gas gathering, processing and transportation businesses. Pursuing assets that build on our objective of improving market access on our existing systems will be given high priority.

The business strategies of our two businesses are as follows:

Liquids

Western Canadian crude oil is an important source of supply serving U.S. requirements. In 2004, Canada supplied approximately 1.6 million 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 60% 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 western Canadian oil sands. With an estimated $60 billion of active or planned projects in the western

Canadian oil sands, new production is expected to grow steadily during the next 5 years, with an additional 600,000 - 800,000 Bpd available by 2010.

Enbridge and the Partnership have been working with our customers to develop market solutions that will enable crude oil shippers to have access to new markets in a timely, cost-effective manner. Our transportation development strategy is to provide Canadian producers with continued access to the premier markets we currently serve, and to move crude oil beyond existing delivery points to reach new markets. We have currently proposed a multi-phase expansion project to CAPP. The first two phases would expand our Lakehead system between Superior, Wisconsin and Chicago, Illinois. The first phase would provide an additional 125,000 Bpd of capacity at a cost of $250 million. We anticipate this additional capacity would be required by 2007. A second phase would provide another 90,000 Bpd at a cost of $150 million, and would be completed in 2008. The last two phases would continue to expand our Lakehead system to Chicago, but would also reach new markets. The third phase would cost about $300 million and would provide incremental capacity of 130,000 Bpd into the Chicago area and south of Chicago. The final phase would then extend this pipeline further south to either Wood River, or Patoka, Illinois, to provide capacity for further Canadian crude movements to the new markets being served from these hubs.

Natural Gas

Our natural gas assets are primarily located in the U.S. Gulf Coast region with significant concentration in Texas. The focus has been on acquiring assets located in areas with strong growth prospects 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 commercial activities and operations of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, the key focus is reliability of service, safety and cost management, 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 the service to our customers by providing producers with a better value for their commodity. This is achieved by increasing their access to 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 markets from the Mid-continent through to Louisiana. From this location, natural gas can connect to all the major market hubs in this region that serve the Midwest and Northeast U.S. natural gas markets. Our trucking operations are used to enhance the value of the liquids 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 by identifying customers with consistent demand for natural gas. Our FERC regulated pipelines provide access to additional markets for some of the natural gas as well.

The growth prospects in our core areas have been improving recently due to the current high commodity prices and expectations that prices will remain high for some time. 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 and new pipelines. We further enhanced several of our systems during 2004 with purchases of connected gathering lines and a small processing plant. In addition, during January 2005 we purchased additional natural gas gathering and processing assets in North Texas from Devon Energy Corporation, which will integrate well with our existing North Texas assets.

BUSINESS SEGMENTS

We conduct our business through three business segments:

- **Liquids.** This segment includes our Lakehead system, a common carrier pipeline, our North Dakota system, a feeder pipeline that transports crude oil and other liquid hydrocarbons, and our Mid-Continent system, which we acquired on March 1, 2004.
  - — Lakehead System: The Lakehead system consists primarily of crude oil and liquid petroleum transportation and storage assets in the Great Lakes and Midwest regions of the United States. The Lakehead system, together with the Enbridge system in Canada owned by Enbridge, forms the longest liquid petroleum pipeline system in the world. The System spans 3,100 miles 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; and, through interconnects, the Patoka/Wood River pipeline hub located in southern Illinois. Deliveries of crude oil and NGLs from the Lakehead system are made, either directly or through connecting pipelines, to refineries and petrochemical plants as feed stock.
  - — North Dakota 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. The North Dakota system connects directly with our Lakehead system.
  - — Mid-Continent System: The Mid-Continent system includes over 480 miles of crude oil pipelines and 9.5 million barrels of storage capacity and serves refineries in the U.S. Mid-continent region from Cushing to Wood River.
- **Natural Gas.** This segment includes the operations of our natural gas gathering and transmission pipelines, treating plants and processing plants and includes the following major systems at December 31, 2004:
  - — East Texas System: The East Texas system includes approximately 3,200 miles of natural gas gathering and transmission pipelines, ten natural gas treating plants and seven natural gas processing plants. This system includes the system we previously referred to as our Northeast Texas system.
  - — Anadarko System: The Anadarko system consists of 730 miles of pipeline in southwest Oklahoma and the Texas panhandle, one natural gas treating plant and three gas processing plants.
  - — North Texas System: The North Texas system includes approximately 2,000 miles of natural gas gathering pipelines and nine natural gas processing plants.
  - — South Texas System: The South Texas system includes approximately 175 miles of natural gas gathering pipelines, one natural gas treating plant and one natural gas processing plant.
  - — Harmony System: The Harmony system consists of 150 miles of pipeline in southeast Mississippi, two natural gas treating plants and two natural gas processing plants. The Harmony system is being upgraded to integrate a newly acquired natural gas processing plant and related pipeline facilities.
  - — Palo Duro System: The Palo Duro system, which includes approximately 400 miles of natural gas transmission and gathering pipelines, together with 5,200 horsepower of compression, is located in Texas between our existing Anadarko system and our North Texas system.

— Interstate Natural Gas Pipelines: The Kansas Pipeline, Midla Pipeline, AlaTenn Pipeline and UTOS Pipeline systems, which are regulated by the FERC; and

— Intrastate Natural Gas Pipelines: The Bamagas Pipeline, Mid-Louisiana Gas Transmission Pipeline and Magnolia Pipeline systems.

Additionally, our Natural Gas segment includes the transportation of natural gas liquids, crude oil and carbon dioxide by rail and road and the related rail cars, trucks and trailers.

- **Marketing.** This segment provides natural gas supply, transportation, balancing, storage and sales services to producers and wholesale customers.

Liquids Segment

Lakehead system

Our Lakehead system is a FERC regulated interstate common carrier pipeline system. The Lakehead system spans 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 11.3 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 57 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. This flexibility increases utilization of the system and enhances our ability to serve customers.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2004, 36 shippers tendered crude oil and liquid petroleum for delivery through the 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 in decline. More than offsetting this decline is the substantial growth in crude oil production from Canada's prolific oil sands resource. Supply of crude oil from the WCSB has grown consistently since 1999, particularly in the last two years when production from the WCSB has grown by 170,000 Bpd. This growth came at a time when production from western Canada's conventional resources declined by 66,000 Bpd. Production from Canada's oil sands resource has more than replaced the declining conventional production by growing 235,000 Bpd over the last two years. Canada's National Energy Board estimates 2004 production from the WCSB exceeded 2.2 million Bpd placing it on a comparable level with production from key OPEC members Kuwait and Nigeria.

Remaining established conventional oil reserves in Western Canada were estimated to be approximately 5 billion barrels at the end of 2003. During 2003, approximately 50% of conventional production was replaced with reserve additions. Remaining established reserves from oil sands currently 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 the Alberta government, an estimated $23 billion has been spent on oil sands development from 1996 through 2003. The Alberta government further estimates that approximately $60 billion may be spent by 2013, including approximately $11 billion in maintenance capital on existing projects. This estimate includes all announced and planned projects in the oil sands. While it is unlikely that all projects will proceed as planned, the magnitude of the potential is noteworthy. Separately, the Alberta government's utility board estimates future production from the oil sands will increase by nearly 1.1 million barrels per day by 2013 based on a subset of currently approved applications and announced expansions.

Enbridge and the Partnership annually conduct a survey of producers, refiners and government agencies to assess the future supply and demand for WCSB production. The latest survey was conducted at the end of 2004 and reflects both public and confidential information regarding production, refining and pipeline projects. Contrasting with previous surveys, this survey indicates a significantly larger growth in the demand for oil sands production in the traditional PADD II market area, which is the U.S. Government's designation for the area that includes the Great Lakes and Midwest regions of the United States. The recent announcement by Encana Corporation and Premcor Inc. to examine the conversion of Premcor's Lima, Ohio refinery to run 200,000 Bpd of blended heavy oil is indicative of the kind of increases in demand in PADD II identified by the survey. Matching the supply and demand responses from the survey indicates that WCSB production could grow from 2.2 million Bpd in 2004 to between 2.8 - 3.0 million Bpd by 2010. This data is part of a preliminary forecast representing forward-looking information prepared by Management and is subject to change.

The near-term growth in supply comes from the completion of major expansion projects at existing synthetic upgraders and growth of bitumen production from both existing and new SAGD facilities currently under construction in Alberta. Over the next two years, synthetic production capacity is expected to increase by nearly 200,000 Bpd at the existing plants. Syncrude, one of the original oil sands producers in northern Alberta, is expected to complete their Stage 3 expansion later in 2005, increasing production capacity to 350,000 Bpd from current capacity of 240,000 Bpd. Suncor, the other original oil sands producer in northern Alberta, is undertaking an expansion of their existing plant both at their upgrader and their SAGD production facility. Production capacity is expected to grow from 225,000 Bpd to 260,000 Bpd by the end of 2005. On January 4, 2005, Suncor experienced a fire at their upgrader site reducing production by almost half to approximately 110,000 Bpd. The impact of this incident on the in-service date of their expansion is not known, although Suncor has stated that this incident will not impact the expansion, and that capital spending and work plans will proceed as planned.

The 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. Over the next three years, AOSP is planning on a number of de-bottlenecking programs to increase production from 155,000 Bpd to between 180,000 and 200,000 Bpd. On October 19, 2004, a pump failure occurred at AOSP's Scotford upgrader site causing a partial shutdown of the project. Subsequent to the pump failure, during the restart of the affected facilities, a leak from the cooling apparatus was detected resulting in a further delay to the restart of the facilities. AOSP expects production to be restored during the first quarter of 2005.

Over the next two years, unblended bitumen production is expected to start or increase from nearly 20 individual SAGD projects. These projects include the expansions at Canadian Natural Resources Limited's Wolf Lake/Primrose area, Encana Corporation's Foster Creek, Suncor's Firebag and Blackrock Ventures' Seal project. Unblended bitumen production is expected to increase by roughly 140,000 Bpd by the end of 2006, more than offsetting the decline in conventional crude production.

Although substantially all of the crude oil and liquid petroleum delivered through the Lakehead system originates in oilfields in western Canada, the Lakehead system also receives approximately 4% of its receipts from domestic sources including:

- U.S. and Canadian 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 Enbridge and the Partnership's most recent industry survey, we estimate that deliveries on the Lakehead system will average 1.40 million Bpd in 2005, a slight decrease of approximately 20,000 Bpd compared with 2004. The decrease is attributable to the early January 2005 fire at the Suncor oil sands plant. Suncor estimates a full recovery by the third quarter of 2005, resulting in a substantial increase in Lakehead deliveries occurring in late 2005. We expect the Lakehead system deliveries to reach 1.55 million Bpd in 2006, increasing to a range of 1.8 to 1.9 million Bpd by 2010. These estimated deliveries are part of a preliminary forecast representing forward-looking information and are subject to change.

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 forecast the demand for WCSB 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, demand for crude oil in PADD II increased from approximately 3.2 million Bpd in 2002 to approximately 3.3 million Bpd in 2004. At the same time, production of crude oil within PADD II decreased by 15,000 Bpd. This gap is expected to widen, contributing to increased demand for imports of crude oil into PADD II. 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 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.

On December 10, 2004, Enbridge announced that its Spearhead project had received sufficient commitments to proceed with plans to reverse the direction of flow on the pipeline from a northerly flow to a southerly flow. The Spearhead Pipeline is a 650 mile pipeline currently running from Cushing to Chicago. Enbridge purchased the pipeline from BP Pipelines North America Inc. in 2003. The recent open season resulted in 10-year shipping commitments of an initial 60,000 Bpd, increasing to 75,000 Bpd by 2009. Enbridge expects to have the line in service during the first quarter of 2006, with initial capacity of 125,000 Bpd. The line could subsequently be expanded to accommodate up to 160,000 Bpd. The reversed line will originate from the Griffith, Indiana terminal on our Lakehead system and the connection to this new market should support increased throughput on the Lakehead system.

During 2004, ExxonMobil Pipeline Company approached CAPP and prospective shippers with a proposal to reverse the direction of flow on their Beaumont, Texas to Corsicana, Texas and their Corsicana, Texas to Patoka pipelines. The combined reversed pipeline will be linked to the Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka. Mustang Pipe Line Partners system is 30% owned by an affiliate of Enbridge. Following successful completion of their open season and with financial support from CAPP and Enbridge, the reversed pipeline is expected to transport between 50,000 and 80,000 Bpd of WCSB crude to the refinery market located in Beaumont on the U.S. Gulf Coast. The connection of the Lakehead system with this new market should also support increased throughput on the Lakehead system; however, the reversed system will also be capable of transporting WCSB crude moved via other competing pipelines into Patoka.

The previously announced closure of Petro-Canada's Oakville, Ontario refinery has been delayed into the first quarter of 2005. A portion of the facility was closed in the fall of 2004, resulting in a modest decline in the volume of crude oil delivered by the Lakehead system to the province of Ontario. Future Lakehead system deliveries into Ontario are expected to remain relatively constant at this reduced level.

In anticipation of improving supply and demand fundamentals, a major expansion of the System was commenced in 1999. This expansion, referred to as the Terrace expansion program, was contractually agreed with CAPP and consists of a multi-phase expansion of both the Canadian and U.S. portions of the System. With the completion of the Terrace expansion program, approximately 350,000 Bpd of incremental capacity has been added to the System. In 2004, we completed construction of additional facilities to expand pipeline capacity into the Chicago market.

Competition. The 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), and the Anacortes area of Washington State (PADD V). In each of these areas, WCSB crude competes with local and imported crude oil to feed refineries to produce refined products (mainly gasoline, diesel, and jet fuel). As local crude production declines and refineries demand more imported crude in each PADD, imports from the WCSB increase. The latest data available for 2004 shows that, PADD II demanded 3.3 million Bpd while producing 435,000 Bpd, thus importing 2.9 million Bpd. For the first nine months of 2004, PADD II imported approximately 1 million Bpd of crude from Canada. The remaining 1.9 million Bpd was imported from PADD III and offshore sources through the U.S. Gulf Coast. Of the crude oil imported from Canada, actual volumes transported on the Lakehead system averaged 965,000 Bpd. Deliveries on the Lakehead system to PADD II increased by approximately 60,000 Bpd in 2004, a 6% increase over 2003 volumes. In 2004, the Lakehead system delivered 1.42 million Bpd, meeting approximately 83 percent of Minnesota refinery needs; 57 percent of the demand in the greater Chicago area; and 61 percent of Ontario's refinery demand.

In 2004, the Enbridge system transported approximately 71 percent of western Canadian crude oil production to export markets, Ontario, and interconnecting pipelines. The System also transported all of the NGL mix produced in western Canada. At the same time, western Canadian refineries processed approximately 25 percent of WCSB production. The remaining production was transported by systems serving the British Columbia, PADD IV and PADD V markets.

As previously noted in "Item 1. Business,—Business Strategy,—Liquids," Enbridge and the Partnership have proposed a multi-phase expansion project of the Lakehead system to CAPP, to provide additional capacity to the PADD II markets and other new markets. There are currently two other proposed projects that compete with our Lakehead system expansion. During 2004, Koch approached CAPP to indicate their interest in expanding capacity from our Lakehead system's Clearbrook, Minnesota terminal to Flint Hills refinery in Rosemount, Minnesota. Flint Hills owns an interest in the existing pipeline, known as the Minnesota Pipeline, along this corridor. The expansion will be initially designed to transport additional WCSB crude via Clearbrook to fill the 50,000 Bpd announced expansion at the Rosemount facility. Koch also owns an existing pipeline serving the Rosemount refinery from the Wood River area, known as Wood River Pipe Line. As part of their proposal, Koch indicated a willingness to consider a reversal of the Wood River Pipe Line if sufficient demand materializes in the Wood River area and sufficient capacity into Rosemount from Clearbrook is constructed as part of the expansion plans of Koch. Throughput on our Lakehead system to Clearbrook is expected to benefit from the Koch/Flint Hills expansion; however, volumes moving on a reversed Wood River Pipe Line would detract from our Lakehead system throughput downstream of Clearbrook. We are not aware of any recent developments concerning the potential to expand the Minnesota Pipe Line or to reverse the Wood River Pipe Line.

Another proposal that could compete with our planned expansions to PADD II and other markets, was put forward on February 9, 2005, by TransCanada Corporation, in which they proposed a crude oil pipeline from Hardisty, Alberta to Patoka, called the Keystone project. The Keystone project includes converting one of TransCanada's existing natural gas pipelines located in the Canadian provinces of Alberta, Saskatchewan and Manitoba, as well as new pipeline construction in Alberta and the states of North and South Dakota, Iowa and Missouri. TransCanada Corporation estimates the cost of new pipeline construction at $1.7 billion. Subject to receiving sufficient producer and refiner support, TransCanada will be seeking regulatory approval for an estimated 400,000 barrel per day system with an estimated in-service date of 2008 or 2009. CAPP is in the process of evaluating the proposed projects by us and our competitors. Enbridge and the Partnership believe a multi-stage expansion of our system for approximately $700 million, provides a more cost effective solution to future transportation requirements of western Canadian crude oil producers.

To meet demand for WCSB crude in PADD IV and the Puget Sound Area of PADD V, several pipeline systems are available. The Trans Mountain pipeline, owned by Terasen Inc., transports crude oil from Alberta to British Columbia and Washington State. The Express Pipeline, owned equally by Terasen, Borealis Infrastructure Management Inc., and Ontario Teachers' Pension Plan, transports crude from Alberta to the PADD IV region of the U.S. In addition to the Express system, three smaller pipeline systems transport crude into northern PADD IV. The Bow River pipeline, owned by Inter Pipeline Fund, connects with the Milk River pipeline, owned by Plains Marketing Canada, L.P. to transport WCSB crude into Montana. The Rangeland and Mid Alberta Pipelines, both purchased by Pacific Energy Partners, L.P in 2004, collectively transport crude oil from Alberta to Montana. Lastly, Plains Marketing Canada L.P.'s Wascana system transports crude oil from Saskatchewan to eastern Montana. Of the pipelines transporting western Canadian crude oil out of Canada, the Enbridge system provides approximately 76% of the total pipeline design capacity.

Terasen Inc. has undertaken an expansion of their Express pipeline system, which is expected to add 108,000 Bpd of capacity. The expansion project is expected to be complete at the start of the second quarter of 2005, offering 280,000 Bpd of capacity into PADD IV. During the third quarter of 2004, Terasen Inc. completed a 20,000 Bpd expansion of its Trans Mountain system.

The pipeline expansions into PADD IV are in line with management expectations as the PADD IV region indigenous supply continues to decline and refinery demand for crude grows. Management expects the growing supply from Western Canada to substantially exceed the modestly growing requirements of the PADD IV region, leaving the balance to be transported on the Lakehead system.

The following table sets forth Lakehead system average deliveries per day and barrel miles for each of the five-year periods ended December 31, 2004.

	Deliveries				
	2004	**2003**	**2002**	**2001**	**2000**
	(thousands of Bpd)				
United States					
Light crude oil	275	258	266	292	321
Medium and heavy crude oil	785	741	665	663	630
NGL	4	4	6	5	25
Total United States	1,064	1,003	937	960	976
Ontario					
Light crude oil	174	174	171	174	174
Medium and heavy crude oil	81	68	83	77	85
NGL	103	109	111	104	103
Total Ontario	358	351	365	355	362
Total Deliveries	1,422	1,354	1,302	1,315	1,338
Barrel miles (billions per year)	367	345	341	333	341

Mid-Continent system

Our Mid-Continent system is comprised of: the Ozark Pipeline, the West Tulsa pipeline and storage terminals at Cushing and El Dorado, Kansas. These assets were acquired in the first quarter of 2004. The Ozark pipeline transports crude oil from Cushing to Wood River where Ozark delivers to ConocoPhillips' Wood River refinery and interconnects with the WoodPat Pipeline, owned by Marathon Ashland Pipeline L.L.C., and the Wood River Pipeline, operated by Koch Pipeline L.P. The West Tulsa pipeline moves crude oil from Cushing to Tulsa, Oklahoma where it delivers to Sinclair Oil Corporation's Tulsa refinery.

The storage terminals have a nominal storage capacity of 9.5 million barrels of oil consisting of 91 individual storage tanks ranging in size from 55,000 to 308,000 barrels of nominal storage space. We expect to add four new tanks in 2005 to our existing storage facilities in Cushing which will increase our crude oil storage capacity by 2.3 million barrels. In addition to being used for operational purposes, we have contracted with various oil market participants for storage capacity within the storage terminals. Contract fees include fixed monthly capacity fees as well as utilization fees, which are charged for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. The Mid-Continent system operates under month-to-month transportation arrangements and both long-term and spot storage arrangements with its shippers. During 2004, 20 shippers tendered crude oil for service by the Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Following our acquisition of the Mid-Continent system, average daily deliveries on the system were 241,000 Bpd for 2004. For 2005, we expect deliveries to be approximately 230,000 Bpd.

Supply and Demand. The Mid-Continent system is well positioned to capture increasing demand for imported crude oil from west Texas and the U.S. Gulf Coast as well as third-party storage demand. In 2004, PADD II imported 2.9 million barrels per day from outside of the PADD II region. The Enbridge system supplied roughly 1 million barrels per day of crude from Canada leaving 1.9 million barrels per day imported from PADD III and 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. The Ozark 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 the Platte pipeline, owned by Terasen Inc., 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 West Texas Gulf pipeline owned by Sunoco Logistics Partners, L.P. and Chevron Pipeline Co., connecting through the MidValley pipeline owned by Sunoco Logistics Partners, L.P. and BP Pipelines into Ohio.

In addition to movements into Wood River, crude oil in Cushing is transported to Chicago on the BP Pipelines system and moved north of Cushing into El Dorado on the Osage pipeline system, owned by Osage Pipeline Company, L.L.C. With the reversal of the Spearhead pipeline, we expect Canadian crude oil moving on Spearhead to displace U.S. domestic crude currently being run in Cushing ultimately resulting in increased throughput on the Ozark pipeline.

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. In addition to our storage facilities at Cushing others offering storage in the Cushing area include BP

Pipelines, TEPPCO Pipeline, L.P., Koch Pipeline L.P., ConocoPhillips Company, Sunoco Logistics Partners, L.P., Seminole Transportation and Gathering, and Plains All American Pipeline, L.P.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transmission 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 transportation on transmission pipelines. 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, 2004, we have over 9,200 miles of gathering and transmission pipelines, 14 treating plants and 22 processing plants. The treating and processing capacities are currently over 800 MMcf/d and 700 MMcf/d respectively.

We have several treating plants, particularly on the East Texas system, capable of handling sour gas, which has a high hydrogen sulfide and/or carbon dioxide and water content and requires specialized treating processes before it can be delivered for transportation on downstream pipelines. These treating plants are capable of producing approximately 1,100 long tons of sulfur per day.

Effective January 1, 2005, we acquired natural gas gathering and processing assets in North Texas. Facilities acquired include approximately 2,200 miles of gas gathering pipelines and four processing plants with aggregate processing capacity of 121 MMcf/d of natural gas. This system predominantly gathers gas produced from the Forth Worth Basin Conglomerate formation and is located in an area where future drilling is expected from producers extending the Barnett Shale play's western flank. Most of the gas is purchased at the wellhead and must be processed in order to meet downstream pipeline transportation specifications.

Our transmission operations include four major FERC-regulated natural gas interstate transmission pipelines, along with three major intrastate pipelines. Each of our transmission pipeline systems typically consists of a natural gas pipeline, compression, and various interconnects to other pipelines that serve wholesale customers.

Customers. Customers of our gathering, treating and processing systems include both natural gas purchasers and producers. 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 transmission pipelines serve customers in Alabama, Kansas, Louisiana, Mississippi, Missouri and Tennessee. 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. Supply for our gathering, treating and processing services primarily depends upon the rate of depletion 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 depends upon overall economic conditions and the prices of natural gas and NGLs. Three of our larger systems are located in basins that have experienced recent growth in natural gas land purchases, drilling and production.

The 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 has experienced substantial growth. The Bossier trend is located on the western side of the East Texas system. Bossier production has grown from under 200 MMcf/d in 1997 to over 800 MMcf/d in 2004. In 2004, we initiated construction of our 107-mile expansion of our East Texas system to provide customers with access to the Carthage Hub, an important outlet to major markets in the Midwest and Northeast U.S. We expect the construction to be completed in mid-2005 at a cost of approximately $150 million. Once the pipeline is completed we expect to flow approximately 300 MMcf/d from our existing contracts.

A substantial portion of natural gas on the 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 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 development in fracturing the shale formation allows commercial production of this gas. Barnett Shale production has risen from 180 MMcf/d to 1,021 MMcf/d since 1999, with the drilling of over 3,000 wells. Growth in this region is expected for at least ten years.

The Anadarko system is located within the Anadarko Basin. Within that basin, recent growth is occurring in the Granite Wash play, particularly in Hemphill and Wheeler Counties, Texas. We are in the process of constructing our Zybach Processing Plant and related facilities to accommodate volume growth from this new drilling. Completion is anticipated to occur in the first quarter of 2005 with initial capacity of 100 MMcf/d, with an additional expansion of 50 MMcf/d planned for startup late in the third quarter of 2005.

We intend to expand our natural gas gathering and processing services through a combination of internal growth and acquisitions, which should provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers and allow expansion of our treating and processing businesses.

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

The table below indicates the capacity in million cubic feet per day of the transmission and wholesale customer pipelines with firm transportation contracts as of December 31, 2004 and the amount of capacity that is reserved under those contracts as of that date.

Major System	Capacity MMcf/d	Percentage Reserved Under Contract as of December 31, 2004
UTOS system	1,200	0%
Midla system	200	86%
AlaTenn system	200	53%
KPC system	160	94%
Bamagas system	450	61%

The UTOS system transmits natural gas from offshore platforms to other pipelines onshore for further delivery. The UTOS system's average daily throughput during 2004 was 219,000 MMBtu/d. The

FERC has approved our negotiated settlement with UTOS shippers, keeping the current rates in effect through 2006.

The 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. The Bamagas system in northern Alabama serves two power plants and is contiguous with the AlaTenn system. 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, 2004, approximately 74% of the capacity of the Midla system is under contract to affiliated entities.

The KPC system has 82% 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. Competitors of our gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other natural gas gatherers that gather, treat, process and market natural gas or NGLs. Some of these competitors are substantially larger than we are. Competition for these services 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 transmission pipelines are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers served by us 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.

Trucking Operations

We also include our trucking operations in our Natural Gas segment. Trucking operations include the transportation of NGLs, crude oil and carbon dioxide by truck and railcar from wellheads to treating, processing and fractionation facilities and to wholesale customers, such as distributors, refiners and chemical facilities. In addition, the trucking operations market these products. We provide these services using 105 trucks and trailers and 100 rail cars, product treating and handling equipment and over 9,500 bbls of NGL storage facilities. In addition, our CO_2 plant with 250 tons per day of capacity takes excess CO_2 from hydrogen producers and we sell it to a variety of customers. At the end of 2004, we took 50% ownership of an underground propane storage facility in Petal, Mississippi, which will augment 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.

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

Supply and Demand. The areas served by our trucking 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 trucking operations 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 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 operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment provides natural gas supply, transportation, balancing, storage and sales services to producers and wholesale customers on our gathering, transmission and wholesale customer pipelines, as well as interconnected third-party pipelines. In general, our Marketing segment makes natural gas purchases from our gathering systems and from other producers and marketers. We then make natural gas sales to wholesale customers on our transmission and wholesale customer pipelines. Our Marketing segment also arranges transportation for wholesale customers, provides storage services, and contracts capacity on third-party pipeline systems.

Natural gas purchased and sold by our Marketing segment is typically priced based upon a published daily or monthly price index. Sales to wholesale customers incorporate a pass-through charge for costs of transportation and generally include an additional margin.

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.

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.

RISK FACTORS

The following risk factors should be read in conjunction with the other sections in this Report on Form 10-K.

Transportation Volumes

Our financial performance depends to a large extent on the volume of products transported on our pipeline systems. Decreases in the volume of products transported by our systems, whether caused by supply and demand factors in the markets these systems serve, or otherwise, can directly and adversely affect our revenue and results of operations. See "Business Segment—Liquids Segment—Supply and Demand"—and "Business Segments—Natural Gas Segment—Supply and Demand."

Regulation

The tariff rates charged by several of our systems are regulated by the FERC or various state regulatory agencies. If our tariff rates are reduced by one of these regulatory agencies on its own initiative or as a result of challenges by third parties, the profitability of our pipeline businesses may suffer. If we are permitted to raise our tariff rates for a particular pipeline, there may be a significant delay between the time the tariff rate increase is approved and the time that the tariff rate increase actually goes into effect. Furthermore, competition from other pipeline systems may prevent us from raising our rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically propose and implement new rules and regulations, terms and conditions of services and rates subject to their jurisdiction. New initiatives or orders may adversely affect the tariff rates charged for our services. Several states, including Oklahoma and Texas, are taking a more active role in the rate and service regulation of gathering and intrastate transmission natural gas systems. Increased state regulation could adversely impact our natural gas systems.

Competition with Enbridge

Enbridge has agreed with us that, so long as an affiliate of Enbridge is our general partner, Enbridge and its subsidiaries may not engage in or acquire any business that is in direct material competition with our businesses, subject to the following exceptions:

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

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

This agreement also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia, Ontario to Montreal, Quebec. As a result of this reversal, Enbridge competes with us to supply crude oil to the Ontario, Canada market. This competition from Enbridge has reduced our deliveries of crude oil to Ontario.

Market Risk

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

- the ability to negotiate, on a timely basis, natural gas purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers' willingness to use other fuels when natural gas prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results; and
- the ability of our customers to make timely payment, customer default, and concentration of receivables with third parties in the energy sector.

Environmental and Safety Regulations

Our pipeline, gathering, processing and trucking operations are subject to federal and state laws and regulations relating to environmental protection and operational safety. Liquid petroleum and natural gas transportation and processing operations always involve the risk of costs or liabilities related to environmental protection and operational safety matters. It is also possible that we will have to pay amounts in the future because of changes in environmental and safety laws or enforcement policies or claims for environmentally related damage to persons or property. We may not be able to recover these costs from insurance, higher fees or through higher pipeline tariffs rates.

Kyoto Protocol

In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. The Partnership and Enbridge are assessing and evaluating the Canadian federal government's approach to implementation. Until these plans become certain, we will not be able to quantify the impact, if any, of the Kyoto Protocol on our operations. We are encouraged by reactions by western Canadian crude oil producers to Kyoto, particularly their commitment to oil sands development, which supports the outlook for the sustainability of crude oil supplies for the Lakehead system.

Transportation of Hazardous Materials

Operation of complex liquid petroleum and natural gas transportation and processing systems involve risks, hazards and uncertainties, such as operational hazards and unforeseen interruptions caused by events beyond our control. For example, our East Texas and South Texas systems, and some facilities in Mississippi, handle or transport large quantities of natural gas containing hydrogen sulfide, a highly toxic substance when workers or the public are exposed above safe limits. Some of these pipelines are located in or near densely populated or sensitive environmental areas. A major release of natural gas containing hydrogen sulfide from one of these pipelines or plants could result in severe injuries or death, as well as severe environmental damage. Insurance proceeds may not be adequate to cover all liabilities incurred or lost revenues.

Growth Strategy

The acquisition of complementary energy delivery assets is a focus of our strategic plan. Acquisitions may present various risks and challenges to us, including the risks of making incorrect assumptions in our acquisition models, failing to effectively integrate acquired operations and diversion of management's attention from existing operations. In addition, we may be unable to identify acquisition targets and consummate acquisitions in the future or be unable to raise, on terms acceptable to us, any debt or equity financing that may be required for any such acquisition.

Oil Measurement Losses

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

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

Quantifying oil measurement losses is inherently difficult because physical measurements of volumes are not practical, as products continuously move through our pipelines and virtually all of these pipelines are located underground. Quantifying oil measurement losses is especially difficult for us because of the length of our systems and the number of different grades of crude oil and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses. If there is a material change in these assumptions, it may result in a revision of oil measurement loss estimates.

Conflicts of Interest

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

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

State Tax Legislation

State tax legislation resulting in the imposition of a partnership-level income tax on us could reduce the cash distributions on the common units and the value of the i-units that we will distribute quarterly to Enbridge Management. Currently, state-level income taxation on us is not significant. However, many states have considered increasing their taxes, including some partnership-level taxes, in their recent legislative processes. The enactment of significant legislation imposing partnership-level income taxes could cause a reduction in the value of our units.

REGULATION

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The Lakehead, North Dakota and Ozark systems are 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 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 new or proposed changes to existing rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to order a hearing concerning such rates. 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 the revenues in excess of the prior tariff during the term of the investigation. 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, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment and had not been subject to complaint, protest or investigation, to be just and reasonable under the ICA (i.e., "grandfathered"). The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party would have to show, i) that it was previously contractually barred from challenging the rates; ii) that the economic circumstances, or the nature of service underlying the rate had substantially changed; or iii) that the rate was unduly discriminatory or preferential. These grandfathering provisions and the circumstances under which they may be challenged have received only limited attention from the FERC, causing a degree of uncertainty as to their application and scope. The North Dakota and Ozark systems are largely covered by the grandfathering provisions of the Energy Policy Act. The Lakehead system is not covered by the grandfathering provisions of the Energy Policy Act.

The Energy Policy 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. A pipeline may not be required to reduce its rate below the level grandfathered under the Energy Policy Act. Under Order No. 561, a pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates and settlement as alternatives to the indexing approach, which may be used in certain specified circumstances.

Since 1995, FERC regulated liquid petroleum pipelines have been generally subject to an indexed ceiling rate methodology under which the annual change in the ceiling rate is the annual change in the

PPIFG-1. In December 2000, FERC affirmed this methodology and the existing index. The petroleum industry appealed this decision, and on February 24, 2003, the FERC issued an Order on Remand, replacing the PPIFG-1 index by removing the 1% reduction. During the second quarter of 2003, Flying J, Lion Oil, Sinclair Oil and Tesoro Refining and Marketing filed an appeal against this Order with the U.S. Court of Appeals for the District of Columbia Circuit. This matter is still pending with the Court of Appeals.

We believe that the rates charged 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 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.

Allowance for Income Taxes in Rates

In a 1995 decision involving our Lakehead system, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. Subsequent appeals of this ruling were resolved by settlement and were not adjudicated. In another FERC proceeding involving SFPP, L.P., an unrelated pipeline limited partnership, the FERC held that the limited partnership may 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 U.S. Court of Appeals for the District of Columbia Circuit. On July 20, 2004, in a case styled BP West Coast Products LLC v. FERC (No. 99-1020), the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding certain aspects of the FERC's orders regarding the SFPP case, but reversing the FERC's ruling regarding the proper tax allowance for SFPP. Based on its earlier Lakehead decisions, the FERC had included a tax allowance in the SFPP cost of service representing the percentage interest in the SFPP limited partnership held by SFPP, Inc., a subchapter C corporation. The Court of Appeals rejected the FERC's rationale for its Lakehead policy and instead determined that there should be no tax allowance in the SFPP cost of service because the SFPP limited partnership itself had no tax liability.

The BP West Coast decision is potentially subject to further judicial review through a petition to the Court of Appeals for rehearing or rehearing en banc, or a petition for writ of certiorari to the U.S. Supreme Court, both of which are discretionary forms of review. We do not know at this time whether further review of the BP West Coast tax allowance ruling will occur. Assuming the BP West Coast decision is not modified as a result of further judicial review, the tax allowance ruling could have a negative effect on the tariff rates of one of more of our FERC regulated systems if these rates are challenged on FERC proceeding. The effect of the FERC's policy stated in the Lakehead proceeding (and the results of the ongoing SFPP litigation regarding that policy) 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. Since an income tax allowance is only one of many elements supporting our pipeline rates for service, we cannot predict with certainty what rates we will be allowed to charge in the future, or the potential impact of the BP West Coast decision.

Parties can challenge the rates on our common carrier interstate liquids pipelines on the basis that those rates are not just and reasonable. Such a challenge could seek a prospective change in the pipelines' rates, as well as reparations (i.e., damages for overcharges for specific shippers) for up to two years prior to the date of the complaint. An income tax allowance is one of many elements supporting a pipeline's rates for service (others include, but are not limited to, equity investment, rate of return, operation and maintenance expenses, depreciation and volumes). If a rate review process were to be initiated, and the BP West Coast decision were followed, our tariff rates for our interstate liquids pipelines would no longer include an income tax allowance. Depending on the conclusion reached with respect to the other various rate elements, apart from the income tax allowance, such a ruling could reduce our tariff rates, which would impact our results of operations and cash flows. We cannot predict the likelihood that parties will assert such challenges or that such challenges would succeed.

The Court's decision on the income tax allowance in BP West Coast does not address the rate methodology for interstate natural gas pipelines regulated by the FERC. If the rationale in the BP West Coast decision were extended to FERC regulated natural gas pipelines, the future tariff rates charged by our interstate natural gas pipelines may not include an income tax allowance. Such a change would be prospective only and would not include reparations for prior periods.

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:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the 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. There are two primary methods by which the rates, terms and conditions of service of an interstate natural gas pipeline may be changed. Under the first method, the company voluntarily seeks a tariff change by making a tariff filing with the FERC, which justifies the proposed tariff change and provides notice, generally 30 days, to the appropriate parties. 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 addition to its jurisdiction over our UTOS system under the NGA and the NGPA, the FERC also has jurisdiction over our UTOS system and our offshore gathering systems under the Outer Continental Shelf Lands Act. The OCSLA requires that all pipelines operating on or across the outer continental shelf, referred to as the "OCS," provide open-access, non-discriminatory transportation service on their systems. In 2000, the FERC issued Order Nos. 639 and 639-A, referred to collectively as "Order No. 639," which required gas service providers operating on the OCS to make public their rates, terms and conditions of service. The purpose of Order No. 639 was to provide regulators and other interested parties with sufficient information to detect and to remedy discriminatory conduct by such service providers. In January 2002, the U.S. District Court for the District of Columbia Circuit permanently enjoined the FERC from enforcing Order No. 639, on the basis that the FERC did not possess the requisite rule-making authority under the OCSLA for issuing Order No. 639. The U.S. Court of Appeals for the District of Columbia Circuit affirmed the lower courts ruling by its October 10, 2003 Order, which is now final.

On November 25, 2003 the FERC issued Order No. 2004 governing the Standards of Conduct for Transmission Providers (interstate pipelines). The new standards provide that (1) a Transmission Providers' employees engaged in transmission system operations must function independently from the Transmission Providers' sales or marketing employees and from any employees of their Energy Affiliates; and (2) a Transmission Provider 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 Affiliate. The rule defined an "Energy Affiliate" as any affiliated company that engages in or is involved in transmission transactions in U.S. energy or transmission markets, or one that manages the capacity of a Transmission Provider, or buys, sales, trades or administers natural gas in U.S. markets, or engages in financial transactions relating to the sale or transmission of natural gas in U.S. markets. Affiliated interstate pipelines are not considered Energy Affiliates. However, gatherers, processors, intrastate and Hinshaw pipelines are considered Energy Affiliates, in addition to marketing affiliates. The new rule will result in additional costs and increased difficulty in our operations, although we do not believe that these regulations will affect it any differently than any other interstate pipelines with which we compete.

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 very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue, especially in light of alleged market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce.

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. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to affiliates that do not operate FERC regulated systems. For example, the Texas Railroad Commission has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have 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. Additional rules and legislation pertaining to these matters are considered or adopted from time to time and the DOT is currently in the process of considering additional regulation of gas and crude gathering lines. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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 and these initiatives generally reflect more light-handed regulation. 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, 2004 (including the tariff surcharges related to our Lakehead system expansions) for transportation on the Lakehead system, the rates for transportation of light crude oil from Neche, North Dakota, where the System enters the U.S. (unless otherwise stated), to principal delivery points are set forth below.

	Published Tariff Per Barrel
To Clearbrook, Minnesota	$0.176
To Superior, Wisconsin	$0.341
To Chicago, Illinois area	$0.693
To Marysville, Michigan area	$0.828
To Buffalo, New York area	$0.847
Chicago to the international border near Marysville	$0.309

The rates at December 31, 2004 for medium and heavy crude oils are higher, and those for NGLs are lower than the rates set forth in the table to compensate us 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 agreement described below.

Under a tariff agreement approved by the FERC in 1998, we 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 the Partnership 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 the surcharge to us changed to $0.007 per barrel. The new tariff is expected to be in effect for the next six years, after which time our tariff will return to $0.013 per barrel through 2013, the term of the agreement.

On July 1, 2004, the FERC approved a Facilities Surcharge, which allows for the recovery of costs for enhancements or modifications to the system at shipper request and approved by CAPP. On an aggregate basis, these enhancements or modifications result in significant incremental costs to the pipeline. The basic concept of the Facilities Surcharge as negotiated by Enbridge and CAPP permits us 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. The Facilities Surcharge is a transparent, cost-of-service-based tariff mechanism that will be trued-up each year for actual costs and throughput and will therefore, not be subject to adjustment either upwards or downwards under indexing. The incremental impact of the Facilities Surcharge is minimal, up to approximately three-tenths of a cent per barrel, depending upon the length of haul and the viscosity of the crude transported. The particular projects to be included in the Facilities Surcharge will be determined as the result of a negotiating process between us and CAPP. Initially four projects have been identified and agreed to with CAPP during 2004 for inclusion in the computation of the Facilities Surcharge that was effective on July 1, 2004.

Natural Gas Systems

Tariff rates on the FERC-regulated natural gas pipelines vary by pipeline and, in the case of KPC, by receipt point and delivery point. Competitive forces may prompt us to charge tariff rates below the FERC-approved ceiling 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.

Environmental and Safety Regulation

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 DOT, under the Title 49 United States Code (Pipeline Safety Act) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. 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 "Pipeline Safety Improvement Act of 2002" was enacted reauthorizing and amending the PSA in several important respects. Following requirements of mandates in the PSA, the DOT has issued regulations requiring operators of hazardous liquid and natural gas transmission pipelines subject to the regulations to assess, evaluate, repair and validate, through a comprehensive analysis, the integrity of pipeline segments that, in the event of a leak or failure, could affect a high consequence area. HCA's for liquid pipelines have been defined as: populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. For natural gas pipelines, HCA's are defined as segments in proximity to population density or places of public congregation.

The DOT has issued recent rules on requirements to submit maps, additional reports and enhance operator personnel qualification programs. We anticipate new rules regulating pipeline security, contractor drug testing, inspection, public awareness programs and annual information reporting. The 2002 amendments of the Act also called for expanded regulations for qualification of workers performing safety-related tasks on pipelines, which management expects to be enacted by incorporation of an industry consensus standard currently under development. Management has incorporated many of the anticipated new requirements into procedures and budgets and, while we expect to incur higher regulatory compliance costs, the increase is not expected to be material. Additionally, revised regulations are anticipated that may impose new federal mandates on certain non-DOT jurisdictional pipelines currently classified as "rural gathering lines." Pending specific proposed regulations, we are not certain of the effect or costs that the new requirements may have on our operations.

Various states in which we operate have authority to issue additional regulations affecting intrastate or gathering pipeline design, safety and operational requirements. In particular, during 2003 the State of Oklahoma passed legislation affecting gathering pipeline business activities and in early 2005, the State of Texas proposed new legislation that could, if passed, increase the commercial regulation of gathering pipelines. Pending passage of the final terms, or any of the legislation, management is not certain of the effect on business operations or costs.

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.

Pressure Restrictions on the Lakehead system

Following a leak that occurred on our Lakehead system in July 2002, the federal Office of Pipeline Safety imposed pressure restrictions on the entire line that was affected. We then proposed a return-to-service plan, which included implementing certain internal inspections and other strategies to verify the integrity of the pipeline in the affected area. During 2003, the OPS removed a majority of the restrictions, while directing that a small restriction remain in place in one area of the line in Minnesota. OPS has indicated that this restriction is expected to be removed following another internal inspection and associated pipeline rehabilitation expenditures in 2005, evaluation of the interim performance of the line and assessment of our progress in implementing our risk management plan. Based on our forecast of deliveries for 2005, the remaining ten percent pressure restriction is not expected to negatively impact our earnings.

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. We believe compliance with these CAA and CWA requirements will not have a material adverse effect on our financial condition.

An operating permit excursion occurred at our Bryans' Mill Treating Plant in 2003 where a significant amount (approximately 7000 tons) of sulphur-dioxide (SO^2) was released above permit limits. We self-reported the incident to the applicable state agency. We found a plant catalyst bed to be deficient and corrected the problem. We have augmented our administrative reporting systems and operations procedures to prevent future occurrences. We have accrued a liability for the amount of the expected penalty.

The 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 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. We or our predecessors have operated certain facilities, including the Lakehead system since 1950. Many of our other facilities were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under our control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from our properties may be subject to CERCLA, RCRA and analogous state laws as described above. Under these laws, we could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, Enbridge Management, as the entity with managerial responsibility for us, could also be liable for such costs to the extent that we are unable to fulfill our obligations. We have conducted site investigations at some of our facilities to assess historical environmental issues, and we are currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable government agencies where appropriate.

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

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

EMPLOYEES

We, nor Enbridge Management, have any employees. The General Partner has delegated to Enbridge Management, pursuant to the Delegation of Control Agreement, substantially all of the responsibility for our day-to-day management and operation. The General Partner, however, retains certain functions and approval rights over our operations. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel, who act on Enbridge Management's behalf as its agents. We are ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

Our operations are subject to many hazards inherent in the liquid petroleum and natural gas gathering, processing and transmission industry. We maintain insurance coverage for our operations and properties considered to be customary in the industry. There can be no assurance, however, that insurance coverages we maintain will be available or adequate for any particular risk or loss, or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations or cash flows.

CAPITAL EXPENDITURES

In 2004, we made capital expenditures of $288.8 million, of which $257.2 million was for pipeline system enhancements, and $31.6 million for core maintenance. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Cash Requirements for Future Growth—Capital Spending."

TAXATION

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

Item 2. Properties

We currently conduct business and/or own properties located in 23 states: Alabama, Alaska, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, North Carolina, North Dakota, Oklahoma, South Carolina, Texas, Tennessee and Wisconsin. In general, our systems are located on land owned by others and are operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities. The pumping stations, tanks, terminals and certain other facilities of our systems are located on land that is owned by us, except for five pumping stations that are situated on land owned by others and used by us under easements or permits.

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

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

Item 3. Legal Proceedings

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

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

No matters were submitted to a vote of security holders during the fourth quarter of 2004.

PART II

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

Our Class A common units are listed and traded on the NYSE, the principal market for the Class A common units, under the symbol "EEP." The quarterly price ranges per Class A common unit and cash distributions paid per unit for 2004 and 2003 are summarized as follows:

	First	Second	Third	Fourth
2004 Quarters				
High	$51.33	$51.95	$49.75	$51.90
Low	$47.71	$41.35	$46.22	$45.60
Cash distributions paid	$0.925	$0.925	$0.925	$0.925
2003 Quarters				
High	$45.85	$48.20	$50.33	$52.93
Low	$41.70	$42.00	$45.45	$48.70
Cash distributions paid	$0.925	$0.925	$0.925	$0.925

On February 15, 2005, the last reported sales price of our Class A common units on the NYSE was $54.40. At February 15, 2005, there were approximately 90,000 Class A common unitholders, of which there were approximately 2,000 registered Class A common unitholders of record. There is no established public trading market for our Class B common units, all of which are held by the General Partner, or our i-units, all of which are held by Enbridge Management.

Item 6. Selected Financial Data

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

	Year ended December 31,				
	2004	2003	2002	2001	2000
	(dollars in millions, except per unit amounts)				
Income Statement Data:[2]					
Operating revenue	$4,291.7	$3,172.3	$1,185.5	$ 342.3	$ 307.0
Operating expenses	4,054.5	2,978.0	1,047.5	244.5	189.1
Operating income	237.2	194.3	138.0	97.8	117.9
Interest expense	(88.4)	(85.0)	(59.2)	(59.3)	(60.4)
Rate refunds	(13.6)	—	—	—	—
Other income (expense)	3.0	2.4	(0.2)	0.9	3.4
Minority interest	—	—	(0.5)	(0.5)	(0.7)
Net income	$ 138.2	$ 111.7	$ 78.1	$ 38.9	$ 60.2
Net income per common and i-unit[1]	$ 2.06	$ 1.93	$ 1.76	$ 0.98	$ 1.78
Cash distributions paid per unit	$ 3.70	$ 3.70	$ 3.60	$ 3.50	$ 3.50
Financial Position Data (at year end):[2]					
Property, plant and equipment, net	$2,778.0	$2,465.6	$2,253.3	$1,486.6	$1,281.9
Total assets	3,763.0	3,231.8	2,834.9	1,649.2	1,376.7
Long-term debt, excluding current maturities[3]	1,559.4	1,155.8	1,011.4	715.4	799.3
Loans from General Partner and affiliates	142.1	133.1	444.1	176.2	—
Partners' capital:					
Class A common units[4]	1,021.6	914.9	604.8	577.0	488.6
Class B common units	66.7	64.2	48.7	48.8	42.1
i-units[5]	399.4	370.7	335.6	—	—
General Partner	31.0	27.5	18.8	6.5	5.2
Accumulated other comprehensive (loss) income	(120.8)	(64.0)	(16.3)	11.9	—
	$1,397.9	$1,313.3	$ 991.6	$ 644.2	$ 535.9
Cash Flow Data:					
Cash flows provided by operating activities	$ 245.4	$ 148.2	$ 200.8	$ 125.3	$ 118.9
Cash flows used in investing activities	(419.1)	(431.0)	(557.2)	(302.1)	(22.3)
Cash flows provided by (used in) financing activities	187.6	286.9	376.5	179.8	(99.4)
Acquisitions and capital expenditures included in investing activities, net of acquired working capital	(429.8)	(423.5)	(563.9)	(300.0)	(21.7)

Notes to Selected Financial Data Table

[1] The allocation of net income to the General Partner in the following amounts has been deducted before calculating net income per unit: 2004, $22.5 million; 2003, $19.6 million; 2002, $13.1 million; 2001, $9.1 million; and 2000, $8.8 million.

(2) Our income statement and financial position data reflect the following acquisitions:

- March 2004 acquisition of the Palo Duro system;
- March 2004 acquisition of the Mid-Continent system;
- December 2003 acquisition of the North Texas system;
- October 2002 acquisition of the Midcoast assets including natural gas gathering and transmission pipelines, and natural gas treating and processing assets in the Mid-continent and Gulf Coast regions of the United States;
- November 2001 acquisition of the natural gas gathering, transportation, processing and marketing assets in east Texas; and
- May 2001 acquisition of Enbridge Pipelines (North Dakota) L.L.C.;

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

- The December 2004 issuance of $300 million of senior unsecured notes;
- The April 2004 amendment of our credit facilities to terminate the 364-day revolving credit facility and increase the Three-year term credit facility to $600 million maturing in 2007;
- The January 2004 issuance of $200 million of senior unsecured notes;
- The May 2003 issuance of $400 million of senior unsecured notes;
- January 2002 replacement of the $350 million Revolving Credit Facility with a $300 million Three-year term credit facility and a $300 million 364-day Facility

(4) Our income statement, financial position and cash flow data include the effect of:

- 3.68 million Class A common units in September 2004;
- 0.45 million Class A common units in January 2004;
- 5.0 million Class A common units in December 2003;
- 3.9 million Class A common units in May 2003;
- 2.3 million Class A common units in March 2002;
- 2.3 million Class A common units in November 2001;
- 1.8 million Class A common units in May 2001;

(5) Reflects the issuance of 9.0 million i-units in October 2002 and subsequent quarterly i-unit distributions of 0.8 million, 0.8 million and 0.2 million during 2004, 2003 and 2002, respectively, in lieu of cash distributions.

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

The following discussion and analysis of our financial condition and results of operations are based on the Consolidated Financial Statements, which we prepared in accordance with accounting principles generally accepted in the United States of America. The discussion and analysis should be read in conjunction with the Consolidated Financial Statements and our accompanying notes listed in the Index to Consolidated Financial Statements beginning on page F-1 of this Annual Report on Form 10-K.

Business Overview

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

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

We primarily provide fee-based services to our customers to minimize commodity price risks. However, in our natural gas business, a portion of our earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure, we enter into derivative financial instrument ("hedge") transactions.

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

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota, and Mid-Continent systems. The Lakehead and North Dakota systems largely consist of FERC-regulated interstate crude oil and liquid petroleum pipelines. These systems generate most of their revenues by charging shippers a per barrel tariff rate to transport crude oil and liquid petroleum.

Our Lakehead system links crude oil production from western Canada to markets in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Western Canadian crude oil production comes from two primary sources, conventional drilling and oil sands extraction projects. Currently, conventional drilling produces the majority of the supply, however, with the number of new oil sands projects in progress, this stable source of crude oil supply is expected to increase significantly over the next ten years.

Deliveries on our North Dakota system are impacted by the willingness of crude oil producers to maintain their production and exploration activities in North Dakota, Montana and the province of Saskatchewan, Canada. Similar to our Lakehead system, our North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States.

Our Mid-Continent system was purchased in March 2004. These assets consist of approximately 480 miles of crude oil pipelines and 9.5 million barrels of storage capacity, which serve refineries in the U.S. Mid-continent region from Cushing, Oklahoma. This system's revenues are primarily toll or fee-based from a combination of regulated assets and contracted unregulated assets.

Natural Gas

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

- approximately 9,200 miles of natural gas gathering and transmission pipelines including four FERC-regulated transmission pipeline systems;
- fourteen natural gas treating plants
- twenty-two natural gas processing plants; and
- trucks, trailers and railcars used for transporting NGLs, crude oil and carbon dioxide.

We receive revenues in our Natural Gas segment under the following types of arrangements:

Fee-Based Arrangements: Under a fee-based contract, we receive a set fee for gathering, treating, processing and transmission of raw natural gas and providing other gathering services. These revenues correlate with volumes and types of service, and do not depend directly on commodity prices. Revenues of our Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services. Customers of our FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes. Revenues are recognized as natural gas is delivered to customers or as transportation services are rendered. We prefer fee-based contracts because they produce relatively stable cash flows.

Other Arrangements: We also utilize other types of arrangements in our Natural Gas segment, including:

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index. We then resell the natural gas, generally for the index price, keeping the difference as our fee.
- Percentage-of-Proceeds Contracts—Under these contracts, we receive a negotiated percentage of the residue natural gas, NGLs, condensate and/or sulfur, recovered from gathering and processing facilities, which we then sell at market prices.
- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased gas is consumed during processing. We extract and retain the NGLs produced during processing, which we sell at market prices. In instances when we purchase raw gas at the wellhead, we also sell for our own account, at market prices, the residue gas resulting from processing. In those instances where we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with a British thermal unit content equivalent to the original raw gas we received.

Some of these arrangements expose us to commodity price risk, which is mitigated by offsetting physical purchases and sales and the use of derivative financial instruments to hedge open positions. In addition, we occasionally take title to natural gas and NGLs for other reasons, such as to sell these products to customers. We will continue to hedge a significant amount of this commodity price risk to support the stability of cash flows. Please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" for more information.

Marketing

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

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

Marketing pays third-party storage facilities and pipelines for the right to store 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.

Critical Accounting Policies and Estimates

Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires our management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for our estimates is historical experience, consultation with experts and various other assumptions that are believed to be reasonable, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from these estimates under different assumptions or conditions. Any effect on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. We believe our critical accounting policies and estimates discussed in the following paragraphs address the more significant judgments and estimates we use in the preparation of our consolidated financial statements.

Revenue Recognition

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectibility is reasonably assured. For our natural gas businesses, we record an estimate each month for our operating revenues and cost of natural gas based on quantities delivered, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each of the years ended December 31, 2004, 2003 and 2002. These estimates are based on the best available volume and price data. We believe that the assumptions underlying these estimates will not be significantly different from actual amounts due to the routine nature of these estimates and the stability of our processes.

Property, Plant and Equipment

We record property, plant and equipment at its original cost and depreciate our assets over the lesser of their estimated useful lives or the estimated remaining life of crude oil or natural gas production in the basins served by the pipelines. Depreciation is recorded utilizing the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Determining useful life requires various assumptions to be made, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. Changes in any of these assumptions may impact the rate at which depreciation is recognized in our consolidated financial statements. Additionally, if we determine that an asset's undepreciated cost may not be recoverable due to economic obsolescence, the business climate, legal and other factors, we evaluate the asset for impairment and record any necessary reduction in its value as a charge against earnings. If there are changes to any of the estimates and assumptions, actual results may differ. For example, if an average remaining service life of 20 years had been used (compared to the average remaining service life of approximately 27 years in the 2004 results), depreciation expense would be $158.7 million or $41.4 million higher and net income per unit would have been $1.34 or $0.72 lower than 2004 levels. If an average remaining service life of 30 years had been used, depreciation expense would be $105.8 million or $11.5 million lower and net income per unit would have been $2.26 or $0.20 higher than 2004 levels.

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

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Enhancement expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of expenditures that are undertaken in response to developing industry standards include first-time high-resolution integrity tool runs and related comprehensive rehabilitation programs, first-time pipeline pressure testing, and expenditures to install seals, liners, and other equipment to reduce risk of environmental contamination from crude oil storage tanks.

Assessment of Recoverability of Goodwill and Intangibles

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

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

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

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

Derivative Financial Instruments

Net income and cash flows are subject to volatility from changes in market prices such as interest rates, natural gas prices, natural gas liquids prices and fractionation margins. In order to manage the risks to our unitholders, we use a variety of derivative financial instruments to create offsetting positions to specific commodity or interest rate exposures. Under SFAS No. 133, all derivative financial instruments are reflected in the balance sheet at their fair value. For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument's intended use and how it is designated.

Derivative financial instruments qualifying for hedge accounting treatment which we use can be divided into two categories: 1) cashflow hedges, or 2) fair value hedges. Cashflow hedges are entered to hedge the variability in cashflows related to a forecasted transaction. Fair value hedges are entered to hedge the value of a recognized asset or liability.

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

At inception and on an ongoing basis, we also assess whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedged item. To the extent our cash flow hedges are determined to be highly effective, changes in the derivative fair values are recorded as a component of Accumulated Other Comprehensive Income until the hedged transactions occur and are then recognized into earnings. Changes in the fair value of derivatives classified as fair value hedges are recognized in earnings as an offset to the change in fair value of the item hedged. If the hedge is determined to not be highly effective, it can no longer be designated as a cash flow or fair value hedge and changes in the fair value are reported directly in the income statement.

Our earnings are also affected by use of the mark-to-market method of accounting required under GAAP for certain basis swap financial instruments. We use short-term, highly liquid financial instruments such as basis swaps and other contracts to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within our Marketing segment. As of December 31, 2004, certain basis swap financial instruments, however, did not qualify for hedge accounting treatment under SFAS No. 133, and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments may cause our non-cash earnings to fluctuate based upon changes in the underlying indexes, primarily commodity prices. The fair value of these financial instruments is determined using price data from highly liquid markets such as the NYMEX commodity exchange or from OTC market makers.

For the year ended December 31, 2004, we recognized losses of $3.5 million in the Consolidated Statement of Income, as part of the Cost of Natural Gas balance of the Marketing and Natural Gas segments. The fair value of the basis swaps at December 31, 2004, is a payable of $3.5 million, and is included in the Consolidated Statement of Financial Position as part of the Deferred Credits balance. These losses resulted from the negative change in market value of these basis swap hedging portfolio activities. At that date, we had a limited number of basis swap transactions that extend beyond December 31, 2005.

Commitments, Contingencies and Environmental Liabilities

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

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

Oil Shortage Balance and Oil Measurement Losses

Oil shortage balance and oil measurement losses are inherent in the transportation of crude oil due to, among other factors, evaporation, measurement differences and blending of commodities in transit. The estimates are based on mathematical calculations and physical measurement and include assumptions related to the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the system. A material change in these assumptions may result in a change to the carrying value of our oil shortage balance or revision of our oil measurement loss estimates. The balances are included in Accounts Payable and Other in the Consolidated Statements of Financial Position.

Operational Balancing Agreements and Natural Gas Imbalances

Payables and receivables associated with our natural gas pipeline operational balancing agreements and natural gas imbalances are recorded monthly. These balances are either settled on a cash basis or are carried by the pipelines and shippers on an in-kind basis. Accruals associated with these in-kind balances are derived from the best available third party and internal documentation and are valued on a published third party index. If there is a change to these estimates and assumptions, actual results may differ.

Results of Operations

The following table shows our consolidated operating revenues, expenses, operating income, net income and net income per unit.

	Year ended December 31,		
	2004	2003	2002
	(dollars in millions, except per unit amounts)		
Operating Revenues	$ 4,291.7	$ 3,172.3	$ 1,185.5
Expenses	(4,054.5)	(2,978.0)	(1,047.5)
Operating income	$ 237.2	$ 194.3	$ 138.0
Net income	$ 138.2	$ 111.7	$ 78.1
Net income per unit	$ 2.06	$ 1.93	$ 1.76

The primary reasons for the overall increases in 2004 performance, compared with 2003, are the inclusion of results from the North Texas and Mid-Continent acquisitions. The North Texas system was purchased on December 31, 2003, and the Mid-Continent system was purchased on March 1, 2004. The primary reason for the overall increase in 2003 performance, compared with 2002, is the full year contribution from the Midcoast assets which were acquired in October 2002.

The following table reflects operating income by business segment and corporate charges.

	Year ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Operating Income			
Liquids	$139.1	$124.5	$112.1
Natural Gas	98.1	63.6	24.1
Marketing	3.6	9.4	1.8
Corporate, operating and administrative*	(3.6)	(3.2)	—
Total Operating Income	237.2	$194.3	$138.0
Corporate*	(99.0)	(82.6)	(59.9)
Net Income	$138.2	$111.7	$ 78.1

* Corporate consists of interest expense, interest income, minority interest, other charges and certain other operating and administrative costs such as franchise taxes, that are not allocated to the other business segments.

Liquids

	Year Ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Operating revenues	$ 409.3	$ 344.2	$ 334.3
Operating and administrative	(128.9)	(104.1)	(104.7)
Power	(72.8)	(56.1)	(52.7)
Depreciation and amortization	(68.5)	(59.5)	(64.8)
Expenses	(270.2)	(219.7)	(222.2)
Operating income	$ 139.1	$ 124.5	$ 112.1

The following table sets forth the operating statistics for the Liquids assets for the periods presented:

	Year ended December 31,		
	2004	2003	2002
	(average Bpd, in thousands)		
Lakehead system:			
United States	1,064	1,003	937
Province of Ontario	358	351	365
Total deliveries	1,422	1,354	1,302
Barrel miles (billions)	367	345	341
Average haul (miles)	706	698	717
Mid-Continent system deliveries	241	—	—
North Dakota system deliveries	85	77	78

Year ended December 31, 2004 compared with year ended December 31, 2003

Our Liquids segment accounted for $139.1 million of operating income, or 59% of our consolidated operating income in 2004. This was an increase of $14.6 million (12%) over 2003 Liquids operating income. The primary driver of the increase in 2004 was our newly acquired Mid-Continent system, which contributed $13.7 million of operating income to the Liquids segment.

Segment operating revenues increased by $65.1 million (19%) in 2004 compared with 2003, largely due to a $36.7 million contribution from our Mid-Continent system. Operating revenues from our Lakehead system increased $22.9 (7%), mostly due to increased deliveries. Deliveries on our Lakehead system increased 5% during 2004, primarily from increased production of western Canadian crude oil transported on that system. Overall, production of western Canadian crude oil increased in the last two years mainly due to the start up of new oil sands projects in the province of Alberta. These latest oil sands projects differ from conventional oil production in two ways. First, oil sands deposits are a mixture of bitumen, water, sand and clay. As a result, oil production takes the form of either mining the oil sands from subsurface deposits and separating out the water, sand and clay components, or, if the deposits are deeper, heating the reservoir sufficiently to flow the pure bitumen to the surface. Second, the bitumen requires either upgrading or blending prior to being sent to market. The upgrading process partially refines the bitumen into a crude stream, which can be readily refined by most conventional refineries. This product is known as synthetic crude oil. During 2004, crude oil production increased in western Canada, primarily due to the start up of the Athabasca Oil Sands Project ("AOSP") in June 2003. The AOSP is owned by Shell Canada Limited, Chevron Canada Limited and Western Oil Sands L.P., and consists of oil sands mining and bitumen extraction operations with a current capacity of 155,000 Bpd. 2004 deliveries on our Lakehead system reflect a full year's impact from this new source of supply. Operating revenues on our North Dakota system also increased in 2004 by $5.5 million (37%), primarily due to an increase in transportation of longer-haul, higher margin barrels resulting from improved production in Montana.

Operating and administrative expenses for the Liquids segment increased by $24.8 million (24%) in 2004 compared with 2003, mostly due to our new Mid-Continent system, which had operating and administrative expenses of $13.4 million. Operating and administrative expenses on our Lakehead system increased by $10.7 million (11%). This increase was attributable primarily to three factors:

(1) Workforce related costs increased by $7.6 million (17%) due to higher pension and medical costs and other related general and administrative expenses.

(2) Oil measurement losses increased by $7.6 million (103%). Oil measurement losses occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement losses include:

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

During 2004, oil measurement losses increased due to the impact of higher crude oil prices and increased volumes on the system, which contributed to the physical losses. Also included in oil measurement losses was an adjustment to the degradation loss of approximately $3.4 million. This was the result of refinements in the oil measurement loss estimation process in valuing different types of crude on station lines. The refinements were the result of engineering studies completed in the fourth quarter of 2004.

(3) Property taxes increased $2.6 million (15%). We have experienced a trend of increasing property taxes partially due to new facilities placed into service, and also due to increases from the taxing authority in counties and states where our pipeline assets are located.

These increases in operating and administrative expenses on the Lakehead system were partially offset by lower leak remediation and repair costs of approximately $6.1 million (90%).

Power costs increased $16.7 million (30%) in 2004 compared with 2003, mostly due to the growth in volumes on the Lakehead system and higher mill-rates attributable to higher demand and fuel costs. Power costs associated with the Mid-Continent system were $5.2 million in 2004.

Depreciation and amortization increased $9.0 million (15%) over 2003. Depreciation on the Mid-Continent system accounted for $4.4 million and the balance relates to new facilities placed into service in the Liquids segment during 2003 and 2004.

Year ended December 31, 2003 compared with year ended December 31, 2002

Our Liquids segment accounted for $124.5 million of operating income, or 64% of consolidated Partnership operating income in 2003. This was an increase of $12.4 million (11%) over 2002 Liquids operating income. Operating revenue was $9.9 million higher in 2003 compared with 2002 due to higher deliveries on our Lakehead and North Dakota systems, partially offset by slightly lower tariffs. Overall, production of western Canadian crude oil increased in 2003 over 2002 mainly due to the start up of new oil sands projects in the province of Alberta. The new AOSP project contributed incremental supply beginning in July 2003, which had a positive impact on Lakehead system volumes.

On a full year basis, tariffs were lower during 2003 due to negative indexing adjustments calculated under FERC regulations and tariff reductions related to existing agreements with customers. In February 2003, the FERC issued an Order on Remand, which replaced the annual index of PPIFG-1 with an index of Producers Price Index for Finished Goods ("PPIFG") without the minus one percent. The FERC allowed the indexed levels to increase for a short period of time in 2003 to reflect the change in the index during 2002. However, effective July 2003, the PPIFG adjustment was negative.

Power costs increased by $3.4 million (6%) in 2003 to $56.1 million from $52.7 million in 2002 primarily due to the increase in deliveries on the Lakehead system.

Operating and administrative expenses decreased by $0.6 million to $104.1 million in 2003 from $104.7 million in 2002. We experienced higher leak clean-up and remediation costs related to two leaks in Minnesota during 2003, as well as higher workforce costs related to benefits. These increases were offset by lower oil measurement expenses and more labor costs capitalized to construction projects.

Depreciation expense was lower in 2003 by $5.3 million compared with 2002. The decrease was due to revised depreciation rates effective January 1, 2003 on the Lakehead system of $13.4 million, offset by depreciation on new facilities placed into service during the fourth quarter of 2002 and throughout 2003 of $8.1 million. The reduction in depreciation rates pursuant to a third party study, better represents the expected remaining service life of the Lakehead system.

Natural Gas

Our North Texas system was purchased effective December 31, 2003, and therefore, we did not record any results of operations from this system in 2003. The results of operations for the Natural Gas segment include the assets purchased as part of the Midcoast system since our acquisition on

October 17, 2002. Comparative results for 2002 include less than three months of operations from the Midcoast system.

	Year Ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Operating revenues	$ 1,319.9	$ 958.5	$ 593.7
Cost of natural gas	(1,031.8)	(754.9)	(515.5)
Operating and administrative	(138.3)	(102.3)	(39.0)
Depreciation and amortization	(51.7)	(37.7)	(15.1)
Expenses	(1,221.8)	$(894.9)	$(569.6)
Operating income	$ 98.1	$ 63.6	$ 24.1

The table below indicates the average daily volumes for each of the major systems in our Natural Gas segment during each of the years ended December 31, 2004, 2003 and 2002, in million British thermal units per day. The full year volume data for 2002 is shown for informational purposes and includes data from the records of the previous owner, our General Partner, as we did not own all of these systems for the entire year.

	2004	2003	2002
	Average MMBtu/d		
East Texas[1]	676,000	579,000	551,000
Anadarko	339,000	256,000	203,000
North Texas	192,000	—	—
South Texas	40,000	38,000	13,000
UTOS	219,000	213,000	275,000
Midla	103,000	108,000	91,000
AlaTenn	62,000	61,000	54,000
KPC	48,000	53,000	40,000
Bamagas	25,000	14,000	16,000
Other Major Intrastates	194,000	182,000	184,000
Total	1,898,000	1,504,000	1,427,000

(1) East Texas includes the combined systems previously referred to as East Texas and Northeast Texas.

Year ended December 31, 2004 compared with year ended December 31, 2003

Our Natural Gas segment accounted for $98.1 million of operating income, or 41% of consolidated Partnership operating income in 2004. This was an increase of $34.5 million (54%) over 2003 Natural Gas operating income.

Compared with 2003, average daily volumes on our major Natural Gas systems increased 26% in 2004, mostly due to the contribution of our North Texas system from the acquisition date of December 31, 2003. Our North Texas system contributed $22.9 million to operating income in 2004, which was consistent with our expectations for the first year of ownership.

Our East Texas system includes the combined results of the systems previously referred to as East Texas and Northeast Texas. Early in 2004, we completed projects that allowed for the operation of these assets as one integrated system, now referred to as the “East Texas system.” Comparative results have been reclassified to conform to this presentation.

Volumes on our East Texas system increased by 17% in 2004, compared with the same period in 2003, as a result of increased drilling by producers of gas wells in the areas served by the system. These volume increases resulted in higher operating revenue less cost of natural gas of $7.9 million compared with 2003. Unit margins realized on natural gas volumes vary by location. Natural gas producers have concentrated their development efforts on regions that have a smaller incremental benefit to us than some of the natural gas volumes that the new volumes replace. Lower unit margins are attributable to various factors including the quality of the natural gas being connected to our systems and the presence of competing pipeline systems.

High natural gas prices positively impacted volumes on our gathering and processing systems. This positive impact was compounded by favorable processing economics in 2004. The majority of our operating income is derived from fee-based contracts, percentage of index or percentage of proceeds contracts. However, a portion of our operating income is derived from keep-whole processing of natural gas. This contract structure requires us to process natural gas at times when it may not be economical to do so. This can happen when natural gas prices are unusually high or natural gas liquids prices are unusually low. During 2004, natural gas prices were high but were more than offset by favorable NGL prices.

Keep-whole processing is mostly associated with the Anadarko and East Texas systems. Our keep-whole processing is a relatively small but variable element of the Natural Gas segment's operating income. During 2004, operating income associated with keep-whole processing was approximately $17.2 million compared to $1.9 million in 2003.

On our East Texas system, we processed 191,420 MMbtu/d of natural gas in 2004, which was an increase of 28% compared with volumes processed in 2003. Due to more favorable NGL pricing conditions in 2004, processing activities contributed $10.0 million of operating income. This compares with $1.7 million of operating income for processing activities in 2003. The increase in business activity on our East Texas system has resulted in higher operating and administrative expenses of $7.8 million (17%) in 2004 compared with 2003. These costs are mostly variable in nature and relate to higher workforce related costs associated with an increase in our operations staff, as well as higher overall benefit costs and an increase in repairs and maintenance expenses. As a result, operating income on our East Texas system increased $2.9 million (10%) in 2004 compared to 2003.

Volumes on our Anadarko system increased by approximately 32% in 2004, compared with the same period in 2003. The growth is a result of increased drilling activity in the Texas panhandle and western Oklahoma regions. The higher volumes contributed to an increase of $11.0 million in operating revenue less cost of natural gas.

Similar to our East Texas system, processing results improved on our Anadarko system during 2004 due to a more favorable natural gas and NGL pricing environment. On our Anadarko system, we processed 111,007 MMbtu/d of natural gas in 2004, which was an increase of 35% compared with volumes processed in 2003. Processing activities contributed $7.2 million of operating income in 2004. This compares with $0.2 million of operating income for processing activities in 2003. These improvements to operating income were partially offset by higher operating and administrative expenses mostly related to variable costs associated with the increased volumes on the system. As a result, operating income on the Anadarko system increased by $16.0 million (175%) in 2004 compared with 2003.

The remainder of the change in operating income in the Natural Gas segment was due to overall decreased results on the balance of our natural gas systems.

We estimate that a $0.05 per MMBtu change in keep-whole processing would increase or decrease total segment operating income by approximately $6 million. A 50,000 MMBtu/d change in gathering volume will increase or decrease operating income by approximately $7 million. These estimates may vary depending upon the pipeline system to which they relate, competition, other factors and are subject to variability.

Year ended December 31, 2003 compared with year ended December 31, 2002

Our Natural Gas segment accounted for $63.6 million, or 33% of consolidated operating income in 2003. This was an increase of $39.5 (164%) over 2002 Natural Gas operating income. Our Natural Gas segment results of operations improved in 2003 due to the full year impact of the Midcoast assets and increased volume of natural gas on the East Texas system.

Increased drilling activity by natural gas producers due to higher natural gas prices was a key contributor to our volume growth. In addition, we initiated modest expansions of our facilities to handle increased customer volumes.

While high natural gas prices positively impacted volumes on our gathering and processing systems, this positive impact was largely offset by poor processing economics in 2003. The majority of our operating income is derived from fee-based contracts, percentage of index or percentage of proceeds contracts. However, a portion of our operating income is derived from keep-whole processing of natural gas. This contract structure requires us to process natural gas at times on limited volumes, when it may not be economical to do so. This can happen when natural gas prices are unusually high or natural gas liquids prices are unusually low.

Keep-whole processing is mostly attributable to the Anadarko and East Texas systems. Our keep-whole processing is a variable element of the Natural Gas segment's operating income. During 2003, operating income associated with keep-whole processing was approximately $1.9 million. This compares to operating income of $63.6 million for the Natural Gas segment as a whole. During 2003, high natural gas prices, particularly at the beginning of the year, adversely affected processing results. In the second half of 2003, processing economics improved marginally as a result of lower natural gas prices. As levels of natural gas in storage increased through the year, natural gas prices decreased.

Performance of our natural gas transmission pipelines depends largely upon revenues derived from reserved pipeline capacity. Transmission revenue is typically higher in the winter months due to increased pipeline rates and greater pipeline reservations; thus, the first and fourth quarter operating income is typically higher as compared with the second and third quarter operating income.

Volumes on the UTOS system decreased 12% in 2003, as compared to the fourth quarter of 2002. This decrease is attributable to both general decline associated with volumes received into the UTOS system and stricter enforcement of gas quality specifications by pipelines downstream of the UTOS Pipeline. The full year impact to revenue in 2003 was less than $0.2 million if these 2003 volumes had remained consistent with the 2002 volumes.

As anticipated, certain customer contracts on the AlaTenn system representing approximately 20% of its capacity terminated during 2003 and were not renewed by the customers. We are exploring alternative customer connections to increase the utilization of this system. High natural gas prices have impacted the anticipated development of increased natural gas demand expected in the Tennessee River Valley area and are a factor in lower utilization of our Bamagas system. This system connects to two new natural gas fueled power plants owned by third parties. Bamagas earns a base return whether the system is used or not because a significant portion of its capacity is contracted on a take-or-pay basis. Nonetheless, increased earnings cannot be realized until the power plants or other facilities transport more natural gas than their contracted take-or-pay levels.

Marketing

Our Marketing segment was established upon our acquisition of the Midcoast system on October 17, 2002, and its results of operations are included in our results since that date. The

Marketing segment's results for 2004 and 2003 reflect a full year's contribution to our operating results compared with less than three months of operating results in 2002.

	Year Ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Operating revenues	$ 2,562.5	$ 1,869.6	$ 257.5
Cost of natural gas	(2,555.3)	(1,857.8)	(255.2)
Operating and administrative	(3.4)	(2.2)	(0.5)
Depreciation and amortization	(0.2)	(0.2)	—
Expenses	(2,558.9)	(1,860.2)	(255.7)
Operating income	$ 3.6	$ 9.4	$ 1.8

Year ended December 31, 2004 compared with year ended December 31, 2003

Our Marketing segment accounted for $3.6 million of operating income, or 2% of consolidated Partnership operating income in 2004. This was a decrease of $5.8 million (62%) compared with 2003 Marketing operating income. Operating income in 2004 for our Marketing segment included a loss of $2.1 million associated with derivatives that do not qualify for hedge accounting treatment under SFAS No. 133. We enter into financial natural gas basis swap transactions to mitigate the risk on index pricing differentials between our physical gas purchases and corresponding gas sales. When the gas sales pricing index is different from the gas purchase pricing index, we are exposed to relative changes in those two index levels. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined natural gas purchase and the natural gas sale, removing any market price risk on the physical transactions. Although this is a sound economic hedging strategy, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the unqualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value will impact the income statement. In 2003, the loss associated with unqualified derivatives was $0.3 million.

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

Year ended December 31, 2003 compared with year ended December 31, 2002

Our Marketing segment accounted for $9.4 million of operating income, or 5% of our consolidated operating income in 2003. This was an increase of $7.6 million (422%) over 2002 Marketing operating income. Colder weather during the first four months of 2003 created greater demand for natural gas, increasing the ability to optimize firm transportation contracts in competitive markets. During 2003, the volume of gas marketed by the Marketing segment was 1,068,000 MMBtu/d. Results for the Marketing segment for the year ended December 31, 2003, also include the positive impact of approximately $1.9 million resulting from the settlement of disputed amounts, which is included in the Consolidated Statement of Income as a reduction of the cost of natural gas.

Typically, the first and fourth quarters will result in higher operating income for the Marketing segment due to colder weather in the market areas served by this segment. Colder weather generates significant incremental sales to our wholesale customers and creates the opportunity to optimize transportation and storage agreements.

Corporate

Interest expense was $88.4 million in 2004 compared with $85.0 million in 2003 and $59.2 million in 2002. The $3.4 million (4%) increase in 2004 compared with 2003 reflects higher average borrowings, partially offset by decreases in our average borrowing rates. The increase of $25.8 million (44%) in 2003 compared with 2002 reflects higher average borrowings during 2003 due to the full year impact on interest expense of the debt assumed upon the acquisition of the Midcoast system in October 2002. The increase was partially offset by lower average borrowing rates from the end of 2001.

Liquidity and Capital Resources

General

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures, debt service payments, distributions to partners and acquisitions of new businesses. Short-term cash requirements, such as operating expenses, maintenance capital expenditures, debt service payments and quarterly distributions to partners, are expected to be funded by operating cash flows. Long-term cash requirements for expansion projects and acquisitions are expected to be funded through several sources, including cash flows from operating activities, borrowings under credit facilities, i-unit payment-in-kind distributions in lieu of cash and the issuance of additional debt and equity securities. Our ability to complete future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating at the time.

On June 30, 2003, we filed a universal shelf registration statement with the SEC. Under this shelf, we may offer and sell debt securities or Class A common units up to a total of $1.5 billion, with the amount, price and terms to be determined at the time of the sale. We expect to use the net proceeds from any future sales of securities under the universal shelf registration statement for operations and for other general corporate purposes, including repayment or refinancing of borrowings, working capital, capital expenditures or acquisitions of businesses or assets. We have effected the following financing transactions using our registration statement:

- In December 2003 and January 2004, we issued an additional 5.45 million Class A common units, which generated net proceeds of $262.0 million, net of underwriters' discounts, commissions and issuance expenses. In addition, the General Partner contributed $5.5 million to maintain its 2% general partner interest in us. Proceeds from the offering were used to reduce borrowings under our 364-day credit facility by approximately $105.0 million, to reduce borrowings under the Three-year term credit facility by approximately $100.0 million and to fund the December 15, 2003 sinking fund payment of $31.0 million on our First Mortgage Notes.
- In January 2004, we issued $200.0 million in principal amount of 4% Senior Notes due 2009, from which we received net proceeds of approximately $198.4 million after offering expenses. The proceeds were used to repay a portion of the amount outstanding under our 364-day revolving credit facility.
- In September 2004, we issued 3.68 million Class A common units at $47.90 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $168.6 million. Proceeds from this offering were used to reduce borrowings under our Three-year term credit facility by approximately $165.0 million. The remaining proceeds

were used to fund our general operations. In addition, the General Partner contributed $3.6 million to maintain its 2% general partner interest in us.

- In December 2004, we issued $200.0 million in principal amount of 5.35% Senior Notes due in 2014 and $100.0 million in principal amount of 6.30% Senior Notes due in 2034, from which we received net proceeds of approximately $297.1 million after offering expenses. The proceeds were used to repay a portion of the amount outstanding under our credit facility.

- In February 2005, we issued 2,506,500 Class A common units at $49.875 per unit, which generated proceeds, net of offering expenses of approximately $124.9 million. Proceeds from this offering were used to repay borrowings under our Three-year term credit facility. In addition, the General Partner contributed $2.7 million to maintain its 2% general partner interest in us.

After giving effect to the preceding transactions, approximately $424.6 million of our debt securities or Class A common units are available for issuance under our existing universal shelf registration statement.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2004:

	2005	2006	2007	2008	2009	Thereafter	Total
			(dollars in millions)				
Long-term debt	$ 31.0	$31.0	$206.0	$31.0	$231.0	$1,060.4	$1,590.4
Power and other purchase commitments	55.7	3.1	—	—	—	—	58.8
Other operating leases	5.7	5.6	3.4	3.4	3.3	1.1	22.5
Right-of-way[(1)]	1.9	1.8	1.8	1.8	1.7	45.0	54.0
Product purchase obligations[(2)]	50.9	50.0	37.7	30.3	0.3	2.5	171.7
Service contract obligations[(3)]	6.3	6.4	5.6	3.3	1.6	—	23.2
Total	$151.5	$97.9	$254.5	$69.8	$237.9	$1,109.0	$1,920.6

(1) Right-of-way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipeline systems, which has been estimated to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2009.

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

(3) The transportation service obligations represent the minimum payment amounts for firm transportation capacity we have reserved on third-party pipelines.

Operating Activities

Net cash provided by operating activities was $245.4 million in 2004 compared with $148.2 million in 2003. Improved operating cash flow was the result of net income contributions from the North Texas and Mid-Continent assets, as well as improved results from our existing assets. The remaining changes in cash from operating activities were due to changes in the operating assets and liabilities from increased natural gas prices in 2004, an increase in natural gas and liquids inventory and general timing differences in the collection on and payment of our current accounts.

At December 31, 2004, our cash and cash equivalents totaled $78.3 million, an increase of $13.9 million from December 31, 2003. Of this amount, $61.0 million was available for cash distributions to our unitholders. Of our cash available for distribution, we retained for use in our business $10.1 million from i-unit holders and $0.2 million from the General Partner. Our fourth quarter distribution to unitholders and the General Partner of $50.7 million ($0.925 per unit), was paid on February 14, 2005.

Investing Activities

Net cash used in our investing activities was $419.1 million for the year ended December 31, 2004, compared with $431.0 million for the prior year. The $11.9 million decrease in funds utilized in investing activities was primarily attributable to two items:

- The dollar value of our acquisitions in 2004 was lower compared with 2003, effectively reducing our cash outflows by $153.2 million. During 2004, we acquired the Mid-Continent and Palo Duro assets and several other smaller assets for $141.0 million. In 2003 our asset acquisitions primarily consisted of $249.6 million of cash we paid for the North Texas system and post-closing adjustments paid to the General Partner related to the Midcoast acquisition of $43.8 million;
- The decrease in our cash used for acquisitions in 2004 was offset by increased cash outflows associated with expansion and growth opportunities of existing assets during 2004 of $159.5 million, as compared to 2003. The increase in property, plant and equipment is primarily due to significant amounts of construction activity during 2004 related to the East Texas expansion program.

During 2004, we spent $288.8 million for capital expenditures including core maintenance and enhancement projects. Core maintenance activities, such as the replacement of equipment and planned major maintenance activities, are performed to enable our systems to operate at their maximum operating capacity. Enhancements to the systems are expected to extend the life of the systems, reduce costs or enhance revenues, and permit us to respond to developing industry and government standards and the changing service expectations of our customers. Our core maintenance capital expenditures increased to $31.6 million for 2004 compared with $28.9 million for 2003, due to the expansion and growth of our existing assets.

Financing Activities

Net cash provided by financing activities was $187.6 million in 2004, compared with $286.9 million in 2003. The decrease of $99.3 million from 2003 is primarily due to fewer unit offerings during 2004 and an increase in our distributions to partners in 2004. Cash distributions to partners increased to $191.0 million in 2004 compared with $156.7 million in 2003 due to:

- an increase in the number of units outstanding; and
- an increase in the general partner incentive distributions, which resulted from increased cash distributions to unitholders.

During 2004, working capital, defined as current assets less current liabilities, improved by $249.3 million to $69.5 million, compared with a deficit of $179.8 million at December 31, 2003. This improvement was primarily due to a reduction in current maturities and short-term debt related to our Senior Credit Facilities. We amended our multi-year revolving credit facility and terminated our 364-day revolving credit facility on April 26, 2004. The amended facility consists of a $600.0 million Three-year term credit facility which matures in 2007.

Cash Distributions

We distribute quarterly, to our General Partner and the holders of our common units, an amount equal to our "available cash," which generally is defined to mean for any calendar quarter the sum of all of our cash receipts plus net reductions to reserves less all of our cash disbursements and net changes to reserves. These reserves are retained to provide for the proper conduct of our business, to stabilize distributions of cash to unitholders and the General Partner and, as necessary, to comply with the terms of any of our agreements or obligations. Enbridge Management, as the delegate of the General Partner under a Delegation of Control Agreement, computes the amount of our available cash.

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our common units, the number of i-units owned by Enbridge Management and the percentage of total units in us owned by Enbridge Management increases automatically under the provisions of the Partnership Agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's shares and voting shares that are then outstanding. The amount of this increase per i-unit is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-day period immediately preceding the ex-dividend date for Enbridge Management's shares. For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units that are issued when a distribution of cash is made to the General Partner and owners of common units is treated as distribution of available cash, even though the i-unit holder will not receive cash. We retain the cash for use in our operations.

During 2004, we distributed a total of 840,239 i-units through quarterly distributions to Enbridge Management, compared with 833,515 in 2003. We retained $38.3 million in 2004 related to the i-unit distributions compared with $35.4 million in 2003.

Credit Facilities and Debt

Our credit facilities and debt consist of the following:

	December 31, 2004	December 31, 2003
	(dollars in millions)	
Short-term debt:		
364-day credit facility	$ —	$ 215.0
Current portion of First Mortgage Notes	31.0	31.0
Total short-term debt	31.0	246.0
Long-term debt:		
Three-year term credit facility	175.0	240.0
First Mortgage Notes	186.0	217.0
4.00% senior notes due 2009 or notes due 2009	200.0	—
7.90% senior notes due 2012	100.0	100.0
4.75% senior notes due 2013	200.0	200.0
5.35% senior notes due 2014	200.0	—
7.00% senior notes due 2018	100.0	100.0
7.125% senior notes due 2028	100.0	100.0
5.95% senior notes due 2033	200.0	200.0
6.30% senior notes due 2034	100.0	—
Unamortized discount	(1.6)	(1.2)
Total long-term debt	$1,559.4	$1,155.8
Loans from General Partner and affiliates	$ 142.1	$ 133.1
Total debt, excluding current portion	$1,701.5	$1,288.9

Credit Facilities. On April 26, 2004, we amended our unsecured multi-year revolving credit facility and terminated our existing 364-day revolving credit facility, each of which was originally entered into in January 2003. The amended facility consists of a $600.0 million Three-year term credit facility, which matures in 2007. Interest is charged on amounts drawn under this facility at a variable rate equal to the Base Rate or a Eurodollar rate as defined in the facility agreement. In the case of Eurodollar rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under our credit rating. As of December 31, 2004, the facility fee was 0.175%. The Three-year term credit facility contains restrictive covenants that required us to maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 5.25 times for eighteen months until September 2005, decreasing to 5.00 times thereafter, as described in the Three-year term credit facility. At December 31, 2004, the interest coverage ratio was approximately 4.3 and the leverage ratio was approximately 4.2. The Three-year term credit facility also places limitations on the amount of debt that may be incurred directly by our subsidiaries. Accordingly, it is expected that we will provide debt financing to our subsidiaries as required. As of December 31, 2004, $175.0 million was drawn on our Three-year term credit facility at a weighted average interest rate of 2.05%.

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

Senior Notes. During the years ended December 31, 2004 and 2003, we made senior note issuances in January and December 2004 and May 2003. These fixed rate notes are:

- our unsecured obligations;
- ranked equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness; and
- effectively junior in right of payment to any secured indebtedness that we may have and to all existing and future indebtedness and other liabilities of our subsidiaries, which own all of our operating assets.

We conduct substantially all of our business through our subsidiaries. The Senior Notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables, of our subsidiaries. As of December 31, 2004 and 2003, our subsidiaries had approximately $517 million and $548 million, respectively, of indebtedness to unaffiliated third parties. The borrowings under these Notes are non-recourse to our General Partner and Enbridge Management. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets to any Person, except in accordance with our agreement. We were in compliance with these covenants at December 31, 2004.

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

In January 2004, we issued $200.0 million in aggregate principal amount of our 4.0% Senior Notes due 2009 in a public offering, from which we received net proceeds of $198.3 million. We used the proceeds to repay a portion of our outstanding debt under bank credit facilities.

In May 2003, we issued $200.0 million in aggregate principal amount of our 4.75% Senior Notes due 2013 and $200.0 million in aggregate principal amount of our 5.95% Senior Notes due 2033 in a private placement. We used the proceeds of approximately $396.3 million, net of expenses of approximately $3.0 million, to repay loans from our affiliates and other bank debt. We recorded a discount of $0.7 million in connection with the issuance of the Senior Notes.

All of the Senior Notes pay interest semi-annually and have varying maturities and terms as previously outlined in the table above. The senior unsecured notes do not contain any covenants restricting the issuance of additional indebtedness.

Loans from General Partner and affiliates. As of December 31, 2004 and 2003, we had $142.1 and $133.1 million, respectively, in debt outstanding under a note to an affiliate of the General Partner. This note relates to debt we assumed in connection with the acquisition of the Midcoast system in October 2002. The note matures in 2007 and has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Three-year term credit facility. The note is subordinate to our Three-year term credit facility and other senior indebtedness. For the years ended December 31, 2004 and 2003, we converted interest payable related to the loans from the General Partner and affiliates in the amount of $9.0 million and $16.1 million, respectively, into long-term debt to the General Partner and affiliates.

Credit Ratings

In October 2004, Standard and Poors lowered our corporate rating from BBB+ (negative outlook) to BBB (stable outlook) and the corporate credit rating of Enbridge Energy, Limited Partnership, our wholly-owned subsidiary, from BBB+ (negative outlook) to BBB (stable outlook). Standard and Poors also lowered the senior unsecured debt rating of Enbridge Energy, Limited Partnership from BBB+ to BBB and lowered the First Mortgage Notes rating of Enbridge Energy, Limited Partnership from A- to BBB+. However, Standard & Poors left unchanged at BBB its senior unsecured debt rating for that subsidiary. Management does not expect Standard and Poors rating actions to have a material impact on the financing capability.

Our senior unsecured debt is rated BBB and Baa2 by Dominion Bond Rating Service and Moody's, respectively. Moody's also rates the senior unsecured debt of Enbridge Energy, Limited Partnership at Baa1.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Cash Requirements for Future Growth

Acquisitions. Our primary strategy is to grow cash distributions through the profitable expansion of our existing assets and through development and acquisition of complementary businesses with risk profiles similar to our current businesses. We will continue to analyze potential acquisitions, with a focus on crude oil, refined products and natural gas pipelines, terminals and related facilities. Major energy companies have sold their non-strategic assets in recent years, continuing the trend of rationalization of the energy infrastructure in the United States. We expect this trend to continue and believe we are well positioned to participate in these opportunities. We will seek opportunities throughout the United States, particularly in the U.S. Gulf Coast area, where asset acquisitions are anticipated in and around our existing natural gas business.

We expect that the funds needed to achieve growth through acquisitions will be obtained through a combination of cash flows from operating activities, borrowings under bank credit facilities, i-unit payment-in-kind distributions in lieu of cash and the issuance of additional debt and equity securities.

Distributions. For the years ended December 31, 2004 and 2003, the declared annual distribution rate was $3.70 per unit. We expect that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, we may temporarily borrow under our credit facilities for the purpose of paying cash distributions until the full impact of operations is realized.

Capital Spending. At December 31, 2004, we had $49.6 million in estimated outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2005.

Expenditures related to property, plant and equipment are capitalized ("capital expenditures"), subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are extended, replaced, or improved; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the established minimum rules are expensed accordingly.

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

In 2005, we anticipate our capital expenditures to approximate:

	(dollars in millions)
System enhancements	$201.5
Core maintenance activities	35.8
Lakehead system expansion projects	4.6
East Texas expansion	48.2
	$290.1

Excluding major expansion projects and acquisitions, ongoing capital expenditures are expected to average approximately $125.0 million annually (approximately 30% for core maintenance and 70% for system enhancements).

We anticipate funding the expenditures temporarily through our bank credit facilities, the commercial paper program we expect to establish during the first quarter of 2005, or with permanent debt and equity funding being provided when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

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

Subsequent Events

Cash Distribution

On January 24, 2005, our Board of Directors declared a distribution payable on February 14, 2005, to our unitholders of record as of February 3, 2005, of our available cash of $61.0 million at December 31, 2004, or $0.925 per common unit. Of this distribution, $50.7 million was paid in cash, $10.1 million was distributed in i-units to holders of our i-units and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

Acquisition

On November 18, 2004, we entered into a definitive agreement to acquire natural gas gathering and processing assets in north Texas for approximately $165.0 million in cash, excluding normal closing adjustments. The asset purchase closed with an effective date of January 1, 2005. We funded the acquisition with borrowings under our existing credit facilities.

The assets purchased primarily serve areas of the Fort Worth Basin, which are mature, but experiencing minimal production decline rates. The assets include approximately 2,200 miles of gas gathering pipelines and four processing plants with aggregate processing capacity of 121 million cubic feet of natural gas per day.

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the gas and then selling the natural gas liquids and residue gas streams. The assets will be included in our Natural Gas segment and will become part of our North Texas system. The purchase price was allocated entirely to the fixed assets purchased, and there was no goodwill recorded.

Class A common unit issuance

In February 2005, we issued 2,506,500 million Class A common units at $49.875 per unit, which generated proceeds, net of offering expenses, of approximately $124.9 million. In addition, the General Partner contributed $2.7 million to the Partnership to maintain its 2% general partner interest in the Partnership. Proceeds from this offering were used to repay borrowings under our Three-year term credit facility.

Commercial Paper Program

During the first quarter of 2005, we plan to establish a $600 million commercial paper program to be backstopped by our $600 million Three-year term credit facility. We expect to reduce our short-term borrowing costs by borrowing in the commercial paper market and repaying all outstanding balances under our $600 million Three-year term credit facility. Our Three-year term credit facility will remain undrawn and available to backstop our commercial paper program. The commercial paper program will not contain any clauses or ratings triggers that would restrict borrowing under the facility. The covenants include a 5.25x maximum Debt/EBITDA (5.00x after September 2005) leverage test and 2.75x EBITDA/Interest coverage test. We have received credit ratings of A-2 and P-2 by Standard and Poor's and Moody's, respectively, on our commercial paper program.

Future Prospects

Liquids

Average daily crude oil deliveries on our Lakehead system are expected to decrease by approximately 20,000 Bpd during 2005, from 1.422 million Bpd in 2004 to approximately 1.40 million Bpd in 2005. The decrease is attributable to the early January 2005 fire at the Suncor oil sands plant in Alberta. Suncor estimates a full recovery by third quarter 2005, resulting in a substantial increase in deliveries on our Lakehead system occurring in late 2005.

Future prospects for our Lakehead system depend upon increased crude oil production from western Canada. While conventional oil supplies in this area are declining, crude oil production from Canada's oil sands supply is increasing. Estimated recoverable crude oil reserves from the oil sands, using existing technology, represent only 10% of the volume in place of approximately 1.6 trillion barrels. To put this in perspective, this total volume in western Canada exceeds the proved reserves of Saudi Arabia. Therefore, this resource is expected to be an important source of crude oil supply for North America in the coming decades. Recognizing this, a number of major oil companies have announced and/or undertaken projects requiring investments of approximately $60 billion over the next decade. This level of investment is expected to increase production of crude oil and enhance utilization of the capacity available on our Lakehead system.

Several major oil sands projects are scheduled for completion over the next few years, including expansions of existing oil sands projects, as well as new projects. The two original oil sands producers, Suncor and Syncrude, are both constructing projects to increase production by the end of 2005 by approximately 150,000 Bpd of additional supply. In addition to the Alberta oil sands, Canada has substantial conventional crude oil resources. Conventional crude oil production will remain sensitive to the price of crude oil and the level of crude oil drilling activity. For a complete discussion of supply and demand for crude oil, please see "Items 1. & 2. Business and Properties."

We and Enbridge recognize the need to expand beyond the Lakehead system's traditional markets, therefore, we have undertaken an Oil Sands Market Study to research supply and disposition of crude oil. The findings indicate that there is demand among U.S. refiners who have not previously had access to Canadian crude oil due to a lack of pipeline infrastructure or economic tariffs. Together, we and Enbridge are focusing on developing transportation solutions to allow PADD II refineries, and ultimately, refiners on the U.S. Gulf Coast, to gain increased or new access to western Canadian crude oil production.

Two tangible steps have already been announced under this initiative. First, Enbridge acquired a 90% stake in a pipeline that runs from Cushing, Oklahoma to Chicago and intends to reverse its flow. The pipeline will be renamed the Spearhead Pipeline and will provide capacity to deliver 125,000 Bpd into the major oil hub at Cushing by 2006. This line could subsequently be expanded to accommodate up to 160,000 Bpd. We expect to benefit following the reversal, as western Canadian crude oil will be carried on the Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. The second step was our proposal to CAPP of a multi-phase expansion of the Lakehead system. The first two phases would expand capacities between Superior, Wisconsin and Chicago, Illinois. In total, these first two phases would provide an additional 215,000 Bpd of capacity at an estimated cost of $400 million. The last two phases would continue to expand our Lakehead system to Chicago, but would also reach new markets. The third phase would cost about $300 million and would provide incremental capacity of 130,000 Bpd into the Chicago area. The final phase would then extend this pipeline further south to either Wood River or Patoka, Illinois to provide capacity for further Canadian crude movements to the new markets being served from these hubs.

Natural Gas

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

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During 2004, increased drilling in the areas where our gathering systems are located has generally exceeded the national trend. One of the prominent areas in which this occurred was the Barnett Shale formation in north Texas, where natural gas production increased from 180 MMcf/d in 1999 to 1,021 MMcf/d in late 2004. The Barnett Shale formation is a prominent new natural gas development within the Fort Worth Basin, not previously accessed by our system. To address this opportunity, we acquired the North Texas system in a transaction that closed on December 31, 2003. The acquired facilities provide approximately 220 MMcf/d of processing capacity. The Barnett Shale is being actively developed, and we anticipate that throughput on the North Texas system will increase modestly in each of the next several years.

We are constructing a new 500 MMcf/d intrastate transmission pipeline to carry increased volumes of natural gas to the pipeline hub at Carthage, Texas. Carthage access is important to natural gas shippers because it offers a number of connections to interstate pipelines, which tend to support more favorable margins to producers. We expect to bring the system on line in mid 2005 and are evaluating other projects that further integrate all our major Texas-centered pipeline systems.

Growth by Acquisitions

Acquisitions are expected to play a role in the achievement of our goals in 2005. In general, these acquisitions are expected to be in or near areas where we already operate and will present the best opportunities for consolidation savings and enhancement of our market position.

We also will evaluate more significant acquisitions. Subject to financing capability, Enbridge plans to use us as its primary vehicle for acquiring mature energy delivery assets, particularly in the Gulf Coast region of the United States. We could make acquisitions directly from Enbridge or its subsidiaries in the future and will continue to pursue strategic acquisitions from unaffiliated parties.

Growth in Cash Distributions

We have modestly grown our cash distributions over the last several years and our distribution coverage has been less than our stated target of 1.1x distributable cash flow. Cash distributions coverage would likely have been greater were it not for lower utilization of the Lakehead system expansions than anticipated when we committed to the expansions in the late 1990's. Increased utilization of the Lakehead system, including the approximately $415.0 million Terrace expansion program, is fundamental to increasing cash distributions above the current $3.70 per unit, per year. It is anticipated that oil sands developments will provide increased utilization of the Lakehead system in the near future. It is also anticipated that oil sands development will support further expansions that will grow our earnings and cash flow. Selected acquisitions and growth of the natural gas segments are also expected to contribute to improved near-term performance.

Regulatory Matters

Rate Refunds

On October 8, 2004, the FERC issued an Order on Remand ("Remand Order") relating to initial rates on our Kansas Pipeline System ("KPC") for the period of time between December 1997 and November 2002. We acquired KPC on October 17, 2002. The Remand Order was issued in response to a United States Court of Appeals ruling in August 2003 requiring the FERC to address the issue of appropriate rate refunds, if any, with respect to KPC's initial rates. In the Remand Order, the FERC found that the proper initial rates are lower than the rates previously charged to customers pending resolution of this contested rate case. In accordance with the FERC's findings, any difference between what was collected and these revised initial Section 7 rates for the period of time between December 1997 and November 2002, plus interest compounded quarterly, is subject to refund.

Refunds to our customers were made in January 2005 pursuant to a refund plan agreed upon with customers and approved by the FERC. Our Consolidated Statements of Income for the year ended December 31, 2004, include a charge of approximately $13.6 million for the rate refunds and interest. The rate refunds relate almost entirely to a time period prior to our ownership of KPC.

Recent Accounting Developments

In March 2004, the Emerging Issues Task Force reached a consensus on issue No. 03-06, *Participating Securities and the Two-Class Method under Financial Accounting Standards Board Statement No. 128. Earnings Per Share* ("EITF 03-06"), which addresses a number of questions regarding the computation of earnings per share by companies that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF 03-06 did not result in a change in our calculation of earnings per unit for any of the periods presented because we had no undistributed net earnings.

A number of accounting standards, interpretations, Emerging Issues Task Force ("EITF") issues, FASB Staff Positions ("FSP"), Statements of Position ("SOP"), etc. have been proposed by the various standard setting authorities in the United States of America, but have not been finalized. We routinely monitor the activities of standard setting authorities and evaluate the effect the proposed guidance may have on our consolidated financial statements. EITF Issue 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* represents a recent proposal regarding how purchases and sales of inventory between entities in the same line of business that are deemed nonmonetary transactions within the scope of APB 29 are to be recorded. We do not have transactions that fall within the scope of this proposed EITF Issue. However, we cannot determine what, if any, effect a final consensus on this issue may have on our consolidated financial statements due to the preliminary nature of the proposal.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate and Foreign Exchange Risk

To the extent the amounts drawn under our credit facilities carry floating rates of interest, our earnings and cash flows are exposed to changes in interest rates. This exposure is managed through periodically refinancing floating rate bank debt with long-term fixed rate debt and through the use of interest rate risk management hedge contracts. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in U.S. dollars. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using forward or other financial derivative contracts.

The table below summarizes, as of December 31, 2004, our derivative financial instruments and other financial instruments that are sensitive to changes in interest rates, including interest rate swaps and debt obligations. For debt obligations, the table presents principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the table presents notional amounts and weighted average interest paid rates by expected (contractual) maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract.

Expected Maturity Date

	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
					(dollars in millions)			
Liabilities								
Fixed Rate:								
First Mortgage Notes	$31.0	$31.0	$ 31.0	$31.0	$ 31.0	$ 62.0	$ 217.0	$ 256.8
Interest Rate	9.15%	9.15%	9.15%	9.15%	9.15%			
Senior Notes	—	—	—	—	200.0	$ 1,000.0	$1,200.0	$1,260.7
Average Interest Rate	—	—	—	—	—	5.72%	—	—
Variable Rate:								
Three-year term credit facility	—	—	$175.0	—	—	—	$ 175.0	$ 175.0
Average Interest Rate	—	—	2.05%	—	—	—	—	—
Interest Rate Derivatives								
Interest Rate Swaps:								
Variable to Fixed	—	—	—	—	—	$ 125.0	$ 125.0	$ (0.9)
Average Pay Rate	—	—	—	—	—	4.35%	—	—
Fixed to Variable	—	—	—	—	—	$ 125.0	$ 125.0	$ 4.6
Average Pay Rate	—	—	—	—	—	Libor-0.22%	—	—

Commodity Price Risk

Our earnings and cash flows associated with our liquids systems are not significantly impacted by changes in commodity prices, as we do not own the crude oil and NGLs we transport. However, we have commodity risk related to degradation losses associated with fluctuating differentials between the price of heavy crude oil relative to light crude oil. Commodity prices have a significant impact on the underlying supply of, and demand for, crude oil and NGLs that we transport.

A portion of our earnings and cash flows in our natural gas segments are exposed to movements in the prices of natural gas and NGLs. We have entered into hedge transactions to substantially mitigate exposure to movements in these prices. Pursuant to policies approved by the Board of Directors of the General Partner, we may not enter into derivative instruments for speculative purposes.

Natural Gas

We enter into natural gas derivative transactions in order to hedge the forecasted purchases or sales of natural gas. The following table details the outstanding derivatives at December 31, 2004 and 2003:

System	Maturity Dates	Notional MMBtu	Fair Value 2004	Fair Value 2003
			(dollars in millions)	
East Texas system	2005-2012	62,102,000	$(100.8)	$(64.8)
North Texas system	2005-2007	6,390,000	$ 4.0	—
Midcoast system	2005-2007	7,374,000	$ —	$ (0.7)
Marketing	2005-2008	385,960,000	$ (11.6)	$ 2.0

Some of our natural gas derivative transactions, which mitigate economic exposures arising from underlying natural gas purchases and sales, do not qualify for hedge accounting treatment under SFAS No. 133. As such, the change in fair market value of these derivative instruments is booked to the income statement. For the years ended December 31, 2004 and 2003, we recorded losses of $3.5 million and $0.3 million, respectively, in the Consolidated Statements of Income as part of the cost of natural gas expense, to account for changes in the fair value.

Natural Gas Liquids

We enter into NGL derivative transactions to hedge the forecasted sales of NGLs. The following table details the outstanding derivatives at December 31, 2004 and 2003:

System	Maturity Date	Notional Barrels	Fair Value 2004	Fair Value 2003
		(in millions)	(dollars in millions)	
East Texas system	2005-2007	2.2	$(9.9)	$(3.2)
Midcoast system	2005-2007	1.8	$(2.0)	$(0.2)
North Texas system	2005-2008	2.7	$(6.7)	$(1.1)

All financial derivative transactions must be undertaken with creditworthy counterparties. As at December 31, 2004, all financial counterparties were rated at least "A" by all major credit rating agencies.

Item 8. Financial Statements and Supplementary Data

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

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

The Partnership and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Management of the Partnership has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2004. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, management of the Partnership relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. No significant changes were made to our internal controls or other factors that could significantly affect these controls subsequent to the date of their evaluation, nor were any corrective actions with respect to significant deficiencies and material weaknesses necessary subsequent to that date.

Management's Report on Internal Control Over Financial Reporting

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

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

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

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

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

Management assessed the effectiveness of the Partnerhip's internal control over financial reporting as of December 31, 2004, based on the framework established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2004.

Management's assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report beginning on page F-2.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

(a) DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name	Age	Position
J.A. Connelly	58	Director
P.D. Daniel	58	Director
E.C. Hambrook	67	Director
M.O. Hesse	62	Director
G.K. Petty	63	Director
D.C. Tutcher	55	President and Director
J.R. Bird	55	Group Vice President—Liquids Transportation and Director
L.A. Zupan	49	Vice President—Liquids Transportation Operations
M.A. Maki	40	Vice President—Finance
T.L. McGill	50	Vice President—Commercial Activity & Business Development & Chief Operating Officer
A.D. Meyer	48	Vice President—Liquids Transportation Technology
R.L. Adams	40	Vice President—Operations and Technologies
D.V. Krenz	53	Vice President
L.S. Cruess	47	Treasurer
J.L. Balko	39	Controller
E.C. Kaitson	48	Assistant Secretary
B.A. Stevenson	49	Corporate Secretary

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

P.D. Daniel was elected a director of the General Partner in July 1996 and served as its President from July 1996 through October 1997. Mr. Daniel has served as President of Enbridge since September 2000 and as Chief Executive Officer of Enbridge since January 2001. Prior to that time Mr. Daniel also served as President & Chief Operating Officer—Energy Delivery of Enbridge from June 1998 to December 2000.

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

M.O. Hesse was elected a director of the General Partner in March 2003 and serves as a member of its Audit, Finance & Risk Committee. Ms. Hesse was President and CEO of Hesse Gas Company from 1990 through 2003. She served as Chairman of the U.S. Federal Energy Regulatory Commission from 1986 to 1989. Ms. Hesse also served as Senior Vice President, First Chicago Corporation and Assistant Secretary for Management and Administration, U.S. Department of Energy. She currently serves as a director of several domestic and international public companies.

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

D.C. Tutcher was elected a director and President of the General Partner in June 2001. He also currently serves as Group Vice President, Transportation South of Enbridge. He was previously Chairman of the Board, President and Chief Executive Officer of Midcoast Energy Resources, Inc. from its formation in 1992 until it was acquired by Enbridge on May 11, 2001.

J.R. Bird served as a director of the General Partner from September 2000 to January 2003 and was reelected as a Director in October 2003. He was elected Vice President, Liquids Transportation of the General Partner in January 2003. He served as President from September 2000 until June 2001. He has also served as Group Vice President, Transportation North of Enbridge since May 2001 and President of Enbridge Pipelines since September 2000. Prior to that time he served as Group Vice President, Transportation from September 2000 through April 2001 and as Senior Vice President, Corporate Planning and Development of Enbridge from August 1997 through August 2000.

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

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

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

A.D. Meyer was elected Vice President, Liquids Transportation Technology, of the General Partner in July 2003. He also continues to serve as Vice President, Technology, Enbridge Pipelines since his appointment in July 1999. Prior to that time he served as President, Enbridge Pipelines (Athabasca) Inc. from October 1997 to July 1999 and as Vice President, Liquids Marketing with Enbridge for the same period.

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

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

L.S. Cruess was elected Treasurer of the General Partner in April 2003. He also has served as Vice President, Financial Services of Enbridge since April 2003. Prior to that time, he served as Vice

President, Corporate Development of Enbridge from 2000 to 2003 and Vice President, Corporate Development of Utilicorp United Inc. from 1996 to 1999.

J.L. Balko was elected Controller of the General Partner in April 2003. Prior to that time, she served as Chief Accountant of the General Partner from October 1999 to April 2003.

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

B.A. Stevenson was elected Corporate Secretary of the General Partner in July 2004. Between 2000 and 2004 Mr. Stevenson held management positions with Reliant Energy, Inc. and Arthur Andersen LLP. Prior to that Mr. Stevenson was General Counsel & Corporate Secretary of Alberta Natural Gas Company Ltd, a Canadian gas processing and transmission company, until 1998 as well as an Associate General Counsel of TransCanada Pipelines from 1998 until 2000.

(b) SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors, executive officers and 10% beneficial owners to file with the SEC, reports of ownership and changes in ownership of our equity securities and to furnish us with copies of all reports filed. Based solely on the review of the reports furnished to us, we believe that, during fiscal year 2004, all Section 16(a) filing requirements applicable to Enbridge Management's directors, officers, and greater than 10% beneficial owners were met.

(c) GOVERNANCE MATTERS

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

The NYSE listing standards require our CEO to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. Accordingly, this certification was provided as required to the NYSE on December 14, 2004.

AUDIT, FINANCE & RISK COMMITTEE

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

The charter of the Audit Committee is filed as an exhibit to this annual report on Form 10-K and is available on our website at *www.enbridgepartners.com*. The Charter of the Audit Committee complies with the listing standards of the NYSE currently applicable to us.

Enbridge Management's Board of Directors has determined that M.O. Hesse, E.C. Hambrook and J.A. Connelly qualify as "Audit Committee financial experts" as defined in Item 401(h) of SEC

Regulation S-K and are independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Exchange Act.

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

CODE OF ETHICS AND STATEMENT OF BUSINESS CONDUCT

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

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

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

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

Item 11. Executive Compensation

The following table sets forth the annual, long-term and other compensation for all services provided in all capacities to Enbridge Management and the Partnership for the fiscal years ended December 31, 2004, 2003 and 2002, of the Chief Executive Officer and four of our other executive officers with the highest salary and bonus compensation in the 2004 fiscal year (the "Named Executive Officers"). The Partnership bears an allocable portion of these officers' total compensation that is based on the approximate percentage of time each of these officers devote to Enbridge Management and the Partnership. The other affiliates of Enbridge, to whom these officers also render services, bear the remainder of the compensation expenses of these officers.

Summary Compensation Table

Name & Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compen-sation[1][2] ($)	Restricted Stock Award(s) ($)	Securities Underlying Options/ SARs[4] (#)	LTIP Payouts ($)	All Other Compen-sation[3] ($)	Approximate Percentage of Time Devoted to Enbridge Management and the Partnership
D.C. Tutcher	2004	322,000	270,000	30,000	—	17,000	—	12,350	90
President	2003	309,750	235,000	35,000	—	50,000	—	10,000	
	2002	296,250	91,000	40,000	—	150,000	—	11,625	
T.L. McGill	2004	231,385	126,500	20,000	—	20,000	—	11,044	90
Vice President—	2003	221,000	89,800	20,000	—	23,200	—	6,361	
Commercial Activity &	2002	182,474	34,000	16,886	—	23,000	—	4,193	
Business Development									
E.C. Kaitson	2004	174,055	59,900	10,000	—	6,500	—	10,643	90
Assistant Secretary and	2003	168,000	35,400	10,000	—	5,900	—	8,375	
Associate General	2002	161,250	18,200	10,000	—	8,300	—	8,990	
Counsel									
M.A. Maki	2004	171,365	87,300	20,000	—	15,000	—	9,444	90
Vice President—	2003	161,750	71,400	20,000	—	16,700	—	7,100	
Finance	2002	136,762	55,700	25,978	—	8,000	—	6,950	
R.L. Adams	2004	161,960	81,600	20,000	—	10,000	—	8,339	90
Vice President—	2003	151,000	54,100	26,229	—	7,500	—	7,568	
Operations and	2002	*	*	*	*	*	*	*	
Technology									

* Elected as an officer in 2003.

(1) Amounts in this column include: the flexible perquisites allowance (as described in Note 2 below), flexible credits paid as additional compensation (as described in Note 2 below), reimbursements for professional financial services, one-time payments for termination benefits, and the taxable benefit from loans by Enbridge, which were granted for relocation or hiring incentive purposes (and amounts reimbursed for the payment of taxes relating to such benefit).

(2) Effective July 1, 2001, Enbridge adopted a flexible benefit program pursuant to which employees receive an amount of flex credits based on their family status and base salary. Beginning in fiscal 2003, the Named Executive Officers were given a Flexible Perquisites Allowance to cover perquisites that may have been previously paid on behalf of each executive. Flex credits can be (a) used to purchase various benefits (such as extended health or dental coverage, disability insurance and life insurance) on the same terms as are available to all employees; (b) applied as contributions to the Stock Purchase and Savings Plan (as described in Note 3 below); or (c) paid to the employee as additional compensation. In 2004, Mr. Tutcher received perquisites and other personal benefits totaling $30,000, all of which related to his Flexible Perquisites Allowance; Mr. McGill received perquisites and other personal benefits totaling $20,000, all of which related to his Flexible Perquisites Allowance; Mr. Maki received perquisites and other personal benefits totaling $20,000, all of which related to his Flexible Perquisites Allowance; Mr. Kaitson received perquisites and other personal benefits totaling $10,000, all of which related to his Flexible Perquisites Allowance, and Mr. Adams received perquisites and other personal benefits totaling $20,000 all of which related to his Flexible Perquisites Allowance.

(3) Employees in the United States participate in the Enbridge Employee Services, Inc. Savings Plan (the “401(k) Plan”) under which employees may contribute up to 25% of their base salary, with employee contributions up to 5% matched by Enbridge (all subject to the contribution limits specified in the Internal Revenue Code). Enbridge’s contributions are used to purchase Enbridge shares at market value and the employees’ contributions may be used to purchase Enbridge shares or nine designated funds. During 2004, Enbridge made contributions of $10,250, $8,977, $8,703, $9,068 and $7,982, respectively, to the 401(k) Plan for the benefit of Mr. Tutcher, Mr. McGill, Mr. Maki, Mr. Kaitson, and Mr. Adams. Additionally, during 2004 Enbridge Employee Services, Inc. paid term life insurance premiums of $540, $508, $380, $376, and $356 for the benefit of Mr. Tutcher, Mr. McGill, Mr. Maki, Mr. Kaitson, and Mr. Adams, respectively. In 2004, Enbridge Employee Services, Inc. also furnished Messrs. Tutcher, McGill and Kaitson with parking benefits, at an annual cost of $1,560 each.

(4) Each option entitles the holder to acquire the indicated number of shares of Enbridge common stock. The costs associated with recognizing the fair value of the options as compensation expense are borne by the Partnership. Additional information is provided in the following section labeled “Stock Options”.

Stock Options

We do not maintain any option or long-term incentive plans for the benefit of the Named Executive Officers. In 2004, Enbridge began allocating to us the compensation expense it recognized in connection with recording the fair value of its outstanding stock options granted to certain of our officers, including the Named Executive Officers. Prior to 2004, we were not allocated any expense associated with stock option grants. The stock options are granted to the Named Executive Officers pursuant to the Enbridge Incentive Stock Option Plan, which is a long-term incentive plan administered by the Human Resources & Compensation Committee of Enbridge. The stock option grants are denominated in Canadian dollars. The following three tables set forth information concerning options granted and exercised during 2004 by the Named Executive Officers under the Enbridge stock option plans:

Options/SAR Grants in Last Fiscal Year

Individual Grants					Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Options Term	
Name	Number of Securities Underlying Options/SARs Granted (#)	Percent of Total Options/SARs Granted to Employees in Fiscal Year	Exercise or Base Price ($Cdn/Sh)	Expiration Date	5% $Cdn	10% $Cdn
D.C. Tutcher	17,000	1.91%	51.44	February 4, 2014	549,956	1,393,696
T.L. McGill	20,000	2.24%	51.44	February 4, 2014	647,007	1,639,642
E.C. Kaitson	6,500	0.73%	51.44	February 4, 2014	210,277	532,884
M.A. Maki	15,000	1.68%	51.44	February 4, 2014	485,255	1,229,732
R.L. Adams	10,000	1.12%	51.44	February 4, 2014	323,503	819,821

Aggregated Option/SAR Exercises in Last Fiscal Year and Fiscal Year End Option/SAR Values

			Number of Securities Underlying Unexercised Options/SARs At Fiscal Year-End		Value of Unexercised In-The-Money Options/SARS At Fiscal Year-End	
Name	Shares Acquired on Exercise (#)	Value Realized ($Cdn)	Exercisable (#)	Unexercisable (#)	Exercisable ($Cdn)	Unexercisable ($Cdn)
D.C. Tutcher	—	—	190,847	187,000	4,656,108	2,729,645
T.L. McGill	—	—	17,300	48,900	285,240	659,820
E.C. Kaitson	—	—	52,035	18,575	1,635,419	280,391
M.A. Maki	11,000	260,638	11,925	32,775	219,984	440,851
R.L. Adams	—	—	5,800	19,550	100,081	250,369

Enbridge also maintains a long-term, performance-based stock unit plan (the "PSU Plan"). Under the PSU Plan, participating executives receive annual grants of PSUs. The initial value of each of these PSUs is equivalent to one Enbridge Share. Each award may be paid out at the end of a three-year performance cycle based on attaining specific goals established by Enbridge's Human Resources & Compensation Committee for performance over a three-year period. Enbridge does not issue any shares in connection with the PSU Plan and if performance fails to meet threshold performance levels, no payments are made. The compensation expense associated with recognizing the fair value of the outstanding stock units attributable to our executive officers that participate in the PSU Plan are allocated to us and expensed in our consolidated statements of income. The following table sets forth the grants made to the Named Executive Officers during 2004 pursuant to the PSU Plan:

Long-Term Incentive Plan Awards Table

Name	Securities, Units or Other Rights (#)	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Securities-Price-Based Plans		
			Threshold[1] (#)	Target[2] (#)	Maximum[3] (#)
D.C. Tutcher . . .	3,545	March 8, 2004-March 7, 2007	886	3,545	7,090
T.L. McGill	—	—	—	—	—
E.C. Kaitson . . .	—	—	—	—	—
M.A. Maki	—	—	—	—	—
R.L. Adams	—	—	—	—	—

(1) "Threshold" refers to the minimum amount payable for a certain level of performance under the PSU Plan.

(2) "Target" refers to the amount payable if the specified performance target is reached.

(3) "Maximum" refers to the maximum payout possible as specified under the PSU Plan.

Pension Plan

The following tables illustrate the benefits payable under the defined benefit component of Enbridge's trusteed non-contributory pension plans (the "Plan"), which apply to the Named Executive Officers of the Partnership. The tables illustrate the total annual pension entitlements assuming the eligibility requirements for an unreduced pension have been satisfied. Plan benefits that exceed maximum pension rules applicable to registered plan benefits are paid from the Enbridge supplemental pension plan. Other trusteed pension plans, with varying contribution formulae and benefits, cover the balance of employees.

For service prior to January 1, 2000, the Plan provides a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 1.6 percent of the sum of (i) the average of the participant's highest annual salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant's three highest annual performance bonus periods, represented in each period by the greater of 50 percent of the actual bonus paid or the lesser of the target bonus and actual bonus, in respect of the last five years of credited service, multiplied by (b) the number of credited years of service. The pension is offset, after age 65, by 50 percent of the participant's Social Security benefit, prorated by years in which the participant has both credited service and Social Security coverage. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements.

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

Pension Plan Tables

Service Prior to January 1, 2000, before Social Security Offset

Remuneration[(1)]	Years of Credited Service					
	10	15	20	25	30	35
$ 200,000	$ 32,000	$ 48,000	$ 64,000	$ 80,000	$ 96,000	$112,000
250,000	40,000	60,000	80,000	100,000	120,000	140,000
300,000	48,000	72,000	96,000	120,000	144,000	168,000
350,000	56,000	84,000	112,000	140,000	168,000	196,000
400,000	64,000	96,000	128,000	160,000	192,000	224,000
450,000	72,000	108,000	144,000	180,000	216,000	252,000
500,000	80,000	120,000	160,000	200,000	240,000	280,000
550,000	88,000	132,000	176,000	220,000	264,000	308,000
600,000	96,000	144,000	192,000	240,000	288,000	336,000
650,000	104,000	156,000	208,000	260,000	312,000	364,000

Service After December 31, 1999

Remuneration[(1)]	Years of Credited Service					
	10	15	20	25	30	35
$ 200,000	$ 40,000	$ 60,000	$ 80,000	$100,000	$120,000	$140,000
250,000	50,000	75,000	100,000	125,000	150,000	175,000
300,000	60,000	90,000	120,000	150,000	180,000	210,000
350,000	70,000	105,000	140,000	175,000	210,000	245,000
400,000	80,000	120,000	160,000	200,000	240,000	280,000
450,000	90,000	135,000	180,000	225,000	270,000	315,000
500,000	100,000	150,000	200,000	250,000	300,000	350,000
550,000	110,000	165,000	220,000	275,000	330,000	385,000
600,000	120,000	180,000	240,000	300,000	360,000	420,000
650,000	130,000	195,000	260,000	325,000	390,000	455,000

(1) "Remuneration" refers to annual salary and that portion of the annual bonus eligible for inclusion in final average earnings.

Mr. Tutcher accumulates pension credits equal to 4.0 percent for each year of service to his tenth anniversary of employment with Enbridge.

For purposes of computing the total retirement benefit of the Named Executive Officers, the following table sets forth the service accrued prior to January 1, 2000, (“Pre 2000 Service”) and service accrued after December 31, 1999 (“Post 1999 Service”) by the Named Executive Officers at December 31, 2004. These figures include the additional service mentioned in the previous paragraph.

Name	Age	Pre 2000 Service	Post 1999 Service
D.C. Tutcher	55	—	3.58
T.L. McGill	50	—	2.83
E.C. Kaitson	48	—	3.58
M.A. Maki	40	13.32	5.00
R.L. Adams	40	14.70	3.50

Item 12. Security Ownership of Certain Beneficial Owners and Management

(a) Security Ownership of Certain Beneficial Owners

The following table sets forth information as of February 15, 2005, with respect to persons known to us to be the beneficial owners of more than 5% of either class of the Partnership's Units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent Of Class
Enbridge Energy Management, L.L.C. . . . . . . 1100 Louisiana, Suite 3300 Houston, TX 77002	i-units	11,101,387	100.0
Enbridge Energy Company, Inc. . . . . 1100 Louisiana, Suite 3300 Houston, TX 77002	Class B Common Units	3,912,750	100.0

(b) Security Ownership of Management and Directors

The following table sets forth information as of February 15, 2005, with respect to each class of our units beneficially owned by the Named Executive Officers, directors and nominees for director of the General Partner and all executive officers, directors and nominees for director of the Partnership as a group:

Name	Title of Class	Amount and Nature of Beneficial Ownership(1)	Percent Of Class
J.A. Connelly	Class A Common Units	5,000	*
P.D. Daniel	Class A Common Units	—	—
E.C. Hambrook	Class A Common Units	2,000	*
M.O. Hesse	Class A Common Units	—	—
G.K. Petty	Class A Common Units	1,000	*
D.C.Tutcher	Class A Common Units	20,200	*
J.R. Bird	Class A Common Units	—	—
L.A. Zupan	Class A Common Units	—	
M.A. Maki	Class A Common Units	—	—
T.L. McGill	Class A Common Units	—	
A.D. Meyer	Class A Common Units	—	—
R.L. Adams	Class A Common Units	—	
D.V. Krenz	Class A Common Units	—	—
L.S. Cruess	Class A Common Units	—	—
J.L. Balko	Class A Common Units	—	—
E.C. Kaitson	Class A Common Units	—	—
B.A. Stevenson	Class A Common Units	—	—
All Officers, directors and nominees as a group 17 persons)	Class A Common Units	28,200	*

* Less than 1%

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

Item 13. Certain Relationships and Related Transactions

Interest of the General Partner in the Partnership

At December 31, 2004, the General Partner owned 3,912,750 Class B Common Units representing a 6.5% limited partner interest in the Partnership. In addition, the General Partner also owns 1,877,638 Listed shares or 17.2% of Enbridge Management's outstanding Listed shares, constituting an effective 3.1% limited partner interest in the Partnership. Together with the 2% general partner interest, the General Partner effectively owns a total of 11.6% of the Partnership and received $37.3 million in cash and incentive distributions.

Interest of Enbridge Management in the Partnership

At December 31, 2004, Enbridge Management owned 10,902,408 i-units, representing an 18.1% limited partner interest in us. The i-units are a separate class of our limited partner interests. All of our i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management's limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the Partnership Agreement and the provisions of Enbridge Management's limited liability company agreement, the number of outstanding Enbridge Management shares and the number of our i-units will at all times be equal.

Cash Distributions

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

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

During 2004, incentive distributions paid to the General Partner were approximately $22.9 million.

Other Related Party Transactions

The Partnership, which has no employees, uses the services of Enbridge and its affiliates (the "Group") for management, operating and administrative services of our business.

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

Item 14. Principal Accountant Fees and Services

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

	For the years ended December 31, 2004	2003
Audit fees[1]	$2,143,655	$ 602,991
Audit related fees[2]	—	14,150
Tax fees[3]	756,868	529,520
All other fees	—	—
Total	$2,900,523	$1,146,661

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

[2] Audit related fees consist of fees billed for professional services rendered for Sarbanes-Oxley Section 404 consultation.

[3] Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1's.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance & Risk Committee of Enbridge Management's Board of Directors or services up to $50,000 may be approved by the Chairman of the Audit, Finance & Risk Committee, under Board of Directors delegated authority. All services in 2004 and 2003 were approved by the Audit, Finance & Risk Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

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

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

b. Consolidated Statements of Income for the years ended December 31, 2004, 2003, and 2002.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2004, 2003, and 2002.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003, and 2002.

e. Consolidated Statements of Financial Position as of December 31, 2004 and 2003.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2004, 2003, and 2002.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

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

(3) *Exhibits.*

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

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

By: /s/ DAN C. TUTCHER
Dan C. Tutcher
(President)

Date: February 25, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 25, 2005 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ DAN. C. TUTCHER	/s/ M.A. MAKI
Dan. C. Tutcher President and Director (Principal Executive Officer)	M.A. Maki Vice President—Finance (Principal Financial Officer)
/s/ J.A. CONNELLY	/s/ E.C. HAMBROOK
J.A. Connelly Director	E.C. Hambrook Director
/s/ G.K. PETTY	/s/ P.D. DANIEL
G.K. Petty Director	P.D. Daniel Director
/s/ M.O. HESSE	/s/ J.R. BIRD
M.O. Hesse Director	J.R. Bird Director

Index to Exhibits

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425)
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001)
3.3	Third Amended and Restated Agreement of Limited Partnership of the Partnership (Exhibit 3.1 to the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002)
4.1	Form of Certificate representing Class A Common Units (Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001)
10.1	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (Exhibit 10.10 to the Partnership's 1991 Form 10-K)
10.2	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (Exhibit 10.11 to the Partnership's 1991 Form 10-K)
10.3	Contribution Agreement (Exhibit 10.1 to the Partnership's Registration Statement on Form S-3/A filed on July 8, 2002)
10.4	First Amendment to Contribution Agreement (Exhibit 10.8 to the Partnership's Registration Statement on Form S-3/A filed on September 24, 2002)
10.5	Second Amendment to Contribution Agreement (Exhibit 99.3 to the Partnership's Current Report on Form 8-K filed on October 31, 2002)
10.6	Delegation of Control Agreement (Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002)
10.7	Amended and Restated Treasury Services Agreement (Exhibit 10.3 to the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002)
10.8	Operational Services Agreement (Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002)
10.9	General and Administrative Services Agreement (Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002)
10.10	Omnibus Agreement (Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002)
10.11	Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.11 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003)
10.12	First Amendment, dated January 12, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q filed on May 4, 2004).

Exhibit Number	Description
10.13	Second Amendment, dated April 26, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q filed on May 4, 2004).
10.14	Amended and Restated 364-Day Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.12 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003)
10.15	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.13 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003)
10.16	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.14 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003)
10.17	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge (U.S.) Inc., as lender (Exhibit 10.15 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003)
10.18	Note Agreement and Mortgage, dated December 12, 1991 (Exhibit 10.1 to the Partnership's 1991 Form 10-K)
10.19	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (Exhibit 10.4 to the Partnership's 1992 Form 10-K)
10.20	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (Exhibit 10.17 to the Partnership's 1996 Form 10-K)
10.21	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project (Exhibit 10.21 to the Partnership's 1998 Form 10-K)
10.22	Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender (Exhibit 10.19 to the Partnership's 1998 Form 10-K)
10.23	Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (Exhibit 10.26 to the Partnership's 1999 Form 10-K)
10.24	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.1 to the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998)
10.25	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.2 to the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998)
10.26	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.3 to the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998)
10.27	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.2 to the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated November 16, 2000)

Exhibit Number	Description
10.28	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.4 to the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998)
10.29+	Executive Employment Agreement, dated May 11, 2001, between Dan C. Tutcher, as Executive, and Enbridge Inc., as Corporation (Exhibit 10.26 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.30+	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (Exhibit 10.27 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.31	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (Exhibit 4.5 to the Partnership's Registration Statement on Form S-4 filed on June 30, 2003)
10.32	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (Exhibit 4.5 to the Partnership's Registration Statement on Form S-4 filed on June 30, 2003)
10.33	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (Exhibit 4.5 to the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.34	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (Exhibit 99.3 to the Partnership's Current Report on Form 8-K filed on January 9, 2004).
10.35	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (Exhibit 4.2 to the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.36	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (Exhibit 4.3 to the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.37	Common Unit Purchase Agreement (Exhibit 1.1 to the Partnership's Current Report on Form 8-K filed on February 10, 2004.
14.1	Code of Ethics for Senior Financial Officers (Exhibit 14.1 to the Partnership's Annual Report on Form 10-K filed on March 12, 2004).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of PricewaterhouseCoopers LLP.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C.

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS,
SUPPLEMENTARY INFORMATION AND
CONSOLIDATED FINANCIAL STATEMENT SCHEDULES
ENBRIDGE ENERGY PARTNERS, L.P.

FINANCIAL STATEMENT SCHEDULES

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

Report of Independent Registered Public Accounting Firm

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

We have completed an integrated audit of Enbridge Energy Partners, L.P.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of comprehensive income, of cash flows and of partners' capital present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Partnership maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Houston, Texas
February 25, 2005

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

	Year ended December 31,		
	2004	2003	2002
	(dollars and units in millions, except per unit amounts)		
Operating revenue	$4,291.7	$3,172.3	$1,185.5
Operating expenses			
Cost of natural gas	3,587.1	2,612.7	770.7
Operating and administrative	274.1	211.8	144.2
Power	72.8	56.1	52.7
Depreciation and amortization	120.5	97.4	79.9
	4,054.5	2,978.0	1,047.5
Operating income	237.2	194.3	138.0
Interest expense	(88.4)	(85.0)	(59.2)
Rate refunds (Note 13)	(13.6)	—	—
Other income (expense)	3.0	2.4	(0.2)
Minority interest	—	—	(0.5)
Net income	$ 138.2	$ 111.7	$ 78.1
Net income allocable to common and i-units	$ 115.7	$ 92.1	$ 65.0
Net income per common and i-unit (basic and diluted) (Note 4)	$ 2.06	$ 1.93	$ 1.76
Weighted average units outstanding	56.1	47.7	36.7
Cash distributions paid per unit	$ 3.70	$ 3.70	$ 3.60

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

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

	Year ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Net income	$138.2	$111.7	$ 78.1
Unrealized loss on derivative financial instruments (Note 14)	(56.8)	(47.7)	(28.2)
Comprehensive income	$ 81.4	$ 64.0	$ 49.9

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Cash provided by operating activities			
Net income	$ 138.2	$ 111.7	$ 78.1
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	120.5	97.4	79.9
Hedge ineffectiveness (Note 14)	3.2	0.3	—
Environmental liabilities (Note 12)	(2.0)	—	—
Other	0.4	(0.7)	(2.9)
Changes in operating assets and liabilities, net of acquired working capital:			
Receivables, trade and other	(25.4)	(21.0)	46.0
Due from General Partner and affiliates	7.2	(7.2)	—
Accrued receivables	(128.5)	(59.2)	(162.0)
Inventory	(60.8)	(10.2)	(5.0)
Current and long-term other assets	15.3	(14.6)	23.7
Due to General Partner and affiliates	0.4	(8.7)	12.5
Accounts payable and other	36.8	(34.1)	(3.6)
Accrued purchases	120.8	76.6	136.4
Interest payable	14.5	15.9	(1.0)
Property and other taxes payable	4.8	2.0	(1.3)
Net cash provided by operating activities	245.4	148.2	200.8
Cash used in investing activities			
Additions to property, plant and equipment	(288.8)	(129.3)	(214.7)
Change in construction payables	10.0	(7.5)	6.7
Asset acquisitions, net of cash acquired (Note 3)	(141.0)	(294.2)	(349.2)
Other	0.7	—	—
Net cash used in investing activities	(419.1)	(431.0)	(557.2)
Cash provided by financing activities			
Proceeds from unit issuances, net (Note 10)	194.2	414.4	424.1
Distributions to partners (Note 10)	(191.0)	(156.7)	(138.1)
Borrowings under debt agreements	3,292.9	2,653.3	2,939.0
Repayments of debt	(3,108.5)	(2,297.0)	(2,643.0)
Borrowings from General Partner and affiliates	—	—	1,074.5
Repayments to the General Partner and affiliates	—	(327.1)	(1,279.1)
Other	—	—	(0.9)
Net cash provided by financing activities	187.6	286.9	376.5
Net increase in cash and cash equivalents	13.9	4.1	20.1
Cash and cash equivalents at beginning of year	64.4	60.3	40.2
Cash and cash equivalents at end of year	$ 78.3	$ 64.4	$ 60.3

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

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

	December 31, 2004	December 31, 2003
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 78.3	$ 64.4
Receivables, trade and other, net of allowance for doubtful accounts of $4.0 in 2004 and $2.9 in 2003	71.7	46.3
Due from General Partner and affiliates	—	7.2
Accrued receivables	378.2	249.7
Inventory (Note 5)	84.5	23.7
Other current assets	13.4	17.5
	626.1	408.8
Property, plant and equipment, net (Note 6)	2,778.0	2,465.6
Other assets, net	27.7	22.9
Goodwill (Note 7)	257.2	257.3
Intangibles, net (Note 8)	74.0	77.2
	$3,763.0	$3,231.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 2.2	$ 1.8
Accounts payable and other	136.4	85.1
Accrued purchases	351.4	230.6
Interest payable	12.3	6.8
Property and other taxes payable	23.3	18.3
Current maturities and short-term debt (Note 9)	31.0	246.0
	556.6	588.6
Long-term debt (Note 9)	1,559.4	1,155.8
Loans from General Partner and affiliates (Note 11)	142.1	133.1
Environmental liabilities (Note 12)	5.3	7.9
Deferred credits	101.7	33.1
	2,365.1	1,918.5
Commitments and contingencies (Note 13)		
Partners' capital (Note 10)		
Class A common units (Units issued—44,296,134 in 2004 and 40,166,134 in 2003)	1,021.6	914.9
Class B common units (Units issued—3,912,750 in 2004 and 2003)	66.7	64.2
i-units (Units issued—10,902,409 in 2004 and 10,062,170 in 2003)	399.4	370.7
General Partner	31.0	27.5
Accumulated other comprehensive loss	(120.8)	(64.0)
	1,397.9	1,313.3
	$3,763.0	$3,231.8

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

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

	Year ended December 31,					
	2004		2003		2002	
	Units	Amount	Units	Amount	Units	Amount
			(dollars in millions)			
Class A common units:						
Beginning balance	40,166,134	$ 914.9	31,313,634	$ 604.8	29,053,634	$ 577.0
Net income allocation	—	85.4	—	64.9	—	52.3
Allocation of proceeds and issuance costs from unit issuance	4,130,000	175.0	8,852,500	368.2	2,260,000	86.2
Distributions	—	(153.7)	—	(123.0)	—	(110.7)
Ending balance	44,296,134	1,021.6	40,166,134	914.9	31,313,634	604.8
Class B common units:						
Beginning balance	3,912,750	64.2	3,912,750	48.7	3,912,750	48.8
Net income allocation	—	8.7	—	8.3	—	7.9
Allocation of proceeds and issuance costs from unit issuance	—	8.2	—	21.7	—	6.1
Distributions	—	(14.4)	—	(14.5)	—	(14.1)
Ending balance	3,912,750	66.7	3,912,750	64.2	3,912,750	48.7
i-units:						
Beginning balance	10,062,170	370.7	9,228,655	335.6	—	—
Net income allocation	—	21.6	—	18.9	—	4.8
Allocation of proceeds and issuance costs from unit issuance	—	7.1	—	16.2	9,000,001	330.8
Distributions	840,239	—	833,515	—	228,654	—
Ending balance	10,902,409	399.4	10,062,170	370.7	9,228,655	335.6
General Partner:						
Beginning balance		27.5		18.8		6.5
Net income allocation		22.5		19.6		13.1
Allocation of proceeds and issuance costs from unit issuance		(0.2)		(0.3)		1.0
General Partner contribution		4.1		8.6		11.5
Distributions		(22.9)		(19.2)		(13.3)
Ending balance		31.0		27.5		18.8
Accumulated other comprehensive loss:						
Beginning balance		(64.0)		(16.3)		11.9
Unrealized loss on derivative financial instruments		(56.8)		(47.7)		(28.2)
Ending balance		(120.8)		(64.0)		(16.3)
Partners' capital at December 31,		$1,397.9		$1,313.3		$ 991.6

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

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

General

Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation assets, natural gas pipelines and related facilities, and marketing assets in the United States of America. The Class A common units of the Partnership are traded on the New York Stock Exchange ("NYSE") under the symbol "EEP".

The Partnership was formed in 1991 by Enbridge Energy Company, Inc. (the "General Partner"), which is an indirect, wholly-owned subsidiary of Enbridge Inc. ("Enbridge") of Calgary, Canada. The Partnership was formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership (the "Lakehead Partnership"). Since 2001, the Partnership has diversified its operations both geographically and by business segments. This has occurred through acquisitions of liquid pipelines and storage assets and natural gas gathering, processing and transportation assets in the Gulf Coast and mid-continent areas of the United States of America. The assets acquired are held in a series of limited liability companies and limited partnerships owned, directly or indirectly, by the Partnership.

Ownership

Ownership of the Partnership as of December 31, 2004 and 2003 is as follows:

	2004	2003
Class A common units owned by the public	73.4%	72.7%
Class B common units owned by the General Partner	6.5%	7.1%
i-units owned by Enbridge Management	18.1%	18.2%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C. and its subsidiary ("Enbridge Management"), a Delaware limited liability company, were formed on May 14, 2002. The General Partner owns all of the voting shares of Enbridge Management. Enbridge Management's Listed Shares are traded on the NYSE under the symbol "EEQ". At December 31, 2004 and 2003, Enbridge Management owned all the Partnership's i-units and receives its earnings from this investment.

Enbridge Management, pursuant to a delegation of control agreement, manages the business and affairs of the Partnership. The Delegation of Control Agreement provides that Enbridge Management will not amend or propose to amend the Partnership's partnership agreement, allow a merger or consolidation involving the Partnership, allow a sale or exchange of all or substantially all of the assets of the Partnership or dissolve or liquidate the Partnership without the approval of the General Partner. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being a limited partner in, and managing the business and affairs of, the Partnership.

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS (Continued)

Enbridge Inc.

Enbridge, a Canadian corporation, is the indirect parent of the General Partner and is traded on the NYSE and Toronto Stock Exchange under the symbol "ENB." Enbridge is a leader in the transportation and distribution of energy, with a focus on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution in North America. Enbridge also has international interests located in Western Europe and Latin America. At December 31, 2004 and 2003, Enbridge and its consolidated subsidiaries owned, through the General Partner, an approximate 11.6% and 12.2% interest, respectively, in the Partnership.

Business Segments

The Partnership conducts its business through three segments: Liquids, Natural Gas, and Marketing.

Effective June 30, 2004, as a result of recent acquisitions and changes in management structure, the Partnership changed its reporting segments. The Natural Gas Transportation segment was combined with the Gathering and Processing segment to form one new segment called "Natural Gas". The Liquids Transportation segment was renamed "Liquids" and there were no changes to the Marketing segment. These changes were a result of stated internal performance measures for the Partnership. The new segments are consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of the Partnership's long-term objectives. Financial information for prior periods has been reclassified to reflect the change in reporting segments.

Liquids

The Liquids segment includes Lakehead, North Dakota, and the Mid-Continent systems. The Lakehead system consists of a common carrier crude oil and liquid petroleum pipeline and storage assets in the Great Lakes and Midwest regions of the United States. The Lakehead system, which has been in operation for over 50 years, spans approximately 1,900 miles and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. In addition, the Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long. The North Dakota system connects directly into the Lakehead system in the state of Minnesota. The Mid-Continent system includes over 480 miles of crude oil pipelines and 9.5 million barrels of storage capacity, and serves refineries in the U.S. Mid-Continent region from Cushing, Oklahoma.

Natural Gas

The Natural Gas segment consists of natural gas gathering and transmission pipelines, treating plants and processing plants. The Natural Gas segment includes 14 natural gas treating plants and 22 natural gas processing plants. In addition, the Natural Gas segment includes approximately 9,200 miles of natural gas gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting natural gas liquids ("NGLs"), crude oil and carbon dioxide.

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS (Continued)

Included in the Natural Gas segment are four Federal Energy Regulatory Commission ("FERC") regulated natural gas transmission pipeline systems located in the mid-continent and Gulf Coast regions of the United States.

Marketing

The Marketing segment primarily provides natural gas supply, transportation, balancing, storage and sales services for producers and wholesale customers on the Partnership's pipelines as well as other interconnected natural gas pipeline systems. Marketing activities are primarily undertaken to increase pipeline utilization, realize incremental margins on gas purchased at the wellhead, and provide value added services to customers.

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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Partnership are prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"). The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. Management regularly evaluates these estimates, utilizing historical experience, consultation with experts and other methods considered reasonable in the circumstances. Nevertheless, actual results may differ significantly from these estimates. Any effects on the consolidated financial statements resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Basis of Presentation and Principles of Consolidation

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

Regulation

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Revenue Recognition

Liquids

Revenues of the Liquids segment are primarily derived from two sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC and merchant storage revenues related to the Partnership's tankage assets. The tariffs specify the amounts to be paid by shippers for service between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. Revenues are recognized upon delivery to customers of products. The merchant storage revenues are recognized based on contractual terms under which customers pay for the option of availability of storage capacity and/or a fee based on through-put volumes. Revenues are recognized as storage services are rendered. The Partnership does not own the crude oil and liquid petroleum that it transports or stores, and therefore, does not assume direct commodity risk.

Natural Gas

Fee-Based Arrangements:

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

Other Arrangements:

The Partnership also utilizes other types of arrangements to derive revenues of the Natural Gas segment, including:

- Percentage-of-Index-Contracts—Under these contracts, the Partnership purchases raw natural gas at a negotiated discount to an agreed upon index price. The Partnership then resells the natural gas, generally for the index price, keeping the difference as its fee.
- Percentage-of-Proceeds Contracts—Under these contracts, the Partnership receives a negotiated percentage of the natural gas it processes in the form of residue natural gas, NGLs, condensate and sulfur, which it then sells at market prices.
- Keep-Whole Contracts—Under these contracts, the Partnership gathers or purchases raw natural gas from the producer for processing. A portion of the gathered or purchased gas is consumed during processing. The Partnership extracts and retains the NGLs produced during processing for its own account, which it sells at market prices. In instances where the Partnership purchases raw gas at the wellhead, it also sells for its own account, the residue gas resulting from

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

processing at market prices. In those instances when the Partnership gathers and processes raw natural gas for the account of the producer, it must return to the producer residue gas with a British Thermal Unit content equivalent to the original raw gas it received.

Some of these other arrangements expose the Partnership to commodity price risk, which the Partnership substantially mitigates with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. Revenues under all arrangements are recognized upon delivery of natural gas and NGLs to customers and/or when services are rendered.

Marketing

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

Cash and Cash Equivalents

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

The Partnership extinguishes liabilities when a creditor has relieved the Partnership of the obligation, which occurs when the Partnership's financial institution honors a check that the creditor has presented for payment. As such, included in Accounts Payable and Other are obligations for which the Partnership has issued check payments that have not yet been presented to the financial institution of approximately $25.3 million and $11.9 million at December 31, 2004 and 2003, respectively.

Allowance for Doubtful Accounts

The Partnership establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

Inventory

Inventory includes product inventory and materials and supplies inventory. The product inventory consists of liquids and natural gas. All inventories are valued at the lower of cost or market. Upon disposition, product inventory is recorded to cost of sales at the weighted average cost of inventory.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Materials and supplies inventory is either used during operations and expensed to operating expenses, or used on capital projects and/or new construction, and capitalized to property, plant and equipment.

Oil Measurement Losses

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

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

There are inherent difficulties in quantifying oil measurement losses because physical measurements of volumes are not practical, as products continuously move through the Partnership's pipelines and virtually all of these pipelines are located underground. Quantifying oil measurement losses is especially difficult for the Partnership because of the length of the pipeline systems and the number of different grades of crude oil and types of crude oil products it carries. The Partnership utilizes engineering-based models and operational assumptions to estimate product volumes in its system and associated oil measurement losses. If there is a material change in these assumptions, it may result in a revision of oil measurement loss estimates in the period determined.

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, many natural gas transmission companies have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in kind through the receipt or delivery of natural gas in the future. Gas imbalances are recorded as current assets or current liabilities on the balance sheet using the posted index prices, which approximate market rates, or the Partnership's weighted average cost of gas.

Property, Plant and Equipment

Property, plant and equipment is stated at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred.

Depreciation rates for the pipeline systems are based on the lesser of the estimated remaining useful lives of the properties or the estimated remaining life of crude oil or natural gas production in the basins served by the pipelines.

The Partnership capitalizes direct costs, such as labor and materials, and related indirect costs, such as overhead and interest at the Partnership's weighted average cost of debt, and, in its regulated

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

businesses that apply the provisions of SFAS No. 71, an equity return component, during construction. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets. For all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal is recognized.

Expenditures related to property, plant and equipment are capitalized ("capital expenditures"), subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are extended, replaced, or improved; or (3) all land, regardless of cost. Acquisition of new assets, additions, replacements and improvements (other than land) costing less than the established minimum rules are expensed accordingly.

The Partnership evaluates its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss will be recognized when the sum of estimated undiscounted future cash flows expected to result from use of the asset and its eventual disposition is less than its carrying amount. If an impairment loss were to be recognized, the amount of the impairment would be calculated as the excess of the carrying amount of the asset over the fair value of the assets either through reference to similar asset sales, or by using a discounted cash flow approach. There have been no impairments recorded in 2004, 2003 or 2002.

Goodwill

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

Effective January 1, 2002, the Partnership adopted SFAS No. 142, *Goodwill and Other Intangible Assets ("SFAS No. 142")*. Goodwill is not amortized, but is tested for impairment annually as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time the Partnership determines that impairment has occurred, the carrying value of the goodwill is written down to its fair value. There have been no impairments recorded in 2004, 2003 or 2002.

Intangibles, Net

Intangibles, net, consist of natural gas purchase and sale customer contracts and natural gas supply opportunities, which are amortized on a straight-line basis over the weighted average useful life of the underlying Assets, which is the period over which the asset is expected to contribute directly or indirectly to the Partnership's future cash flows.

The Partnership evaluates the carrying value of the intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, the Partnership compares the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. There have been no impairments recorded in 2004, 2003, or 2002.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Assets

Other assets primarily include deferred financing charges, which are amortized on a straight-line basis, over the life of the related debt and classified as interest expense on the Consolidated Statements of Income.

Income Taxes

The Partnership is not a taxable entity for federal and state income tax purposes. Accordingly, no recognition is given to income taxes for financial reporting purposes. The tax on Partnership net income is borne by the individual partners through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the Partnership Agreement. The aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in the Partnership is not available.

Derivative Financial Instruments

Net income and cash flows are subject to volatility stemming from changes in market prices such as interest rates, natural gas prices, natural gas liquids prices and processing spreads. In order to manage the risks to unitholders, the Partnership uses a variety of derivative financial instruments to create offsetting positions to specific commodity or interest rate exposures. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133") all derivative financial instruments are recorded in the balance sheet at their fair value. For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument's intended use and how it is designated. For those instruments that do not qualify for hedge accounting, the change in market value is recorded as cost of natural gas in the Consolidated Statements of Income.

In implementing its hedging programs, the Partnership has established a formal analysis, execution and reporting framework that requires the approval of the Board of Directors of the General Partner or a committee of senior management. Derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not used for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment and in use by the Partnership can generally be divided into two categories: 1) cashflow hedges, or 2) fair value hedges. Cashflow hedges are entered into to hedge the variability in cashflows related to a forecasted transaction. Fair value hedges are entered into to hedge the value of a recognized asset or liability.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

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

The Partnership's earnings are also affected by use of the mark-to-market method of accounting required under GAAP for certain basis swap financial instruments. Short-term, highly liquid financial instruments such as basis swaps and other contracts are used to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within the Marketing segment. As of December 31, 2004, certain basis swap financial instruments, however, did not qualify for hedge accounting treatment under SFAS No. 133, and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments may cause non-cash earnings to fluctuate based upon changes in the underlying indexes, primarily commodity prices. The fair value of these financial instruments is determined using price data from highly liquid markets such as the NYMEX commodity exchange or from OTC market makers.

Commitments, Contingencies and Environmental Liabilities

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

recovery is probable, it records and reports an asset separately from the associated liability in its financial statements.

The Partnership recognizes liabilities for other contingencies when it has an exposure that, when fully analyzed, indicates it is either probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Partnership accrues the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss.

Asset Retirement Obligations

Effective January 1, 2003, the Partnership adopted SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"), which addresses accounting and reporting for legal obligations associated with the retirement of long-lived tangible assets. SFAS No. 143 requires entities to record the fair value of a liability for the retirement obligation in the period in which the liability is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying value of the asset, which is subsequently depreciated over its useful life. For offshore pipeline systems, a legal obligation exists for decommissioning requirements. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as settlement dates and the scope of decommissioning work are indeterminate. For a minority of onshore rights-of-way agreements, a legal obligation may be construed to exist due to the requirement to remove the pipe at final abandonment. However, the fair value of the asset retirement obligation cannot be reasonably estimated, as the settlement dates are indeterminate. In certain rate jurisdictions, the Partnership is permitted to include annual charges for removal costs in its regulated cost of service rates charged to customers. For the year ended December 31, 2004 and 2003, the Partnership recorded long-term liabilities of $0.1 million and $0.8 million, respectively, with a resulting increase in the related Property, Plant and Equipment in the Consolidated Statements of Financial Position and a corresponding accretion expense of $0.1 million and $0.1 million in the Consolidated Statements of Net Income.

Comparative Amounts

Certain reclassifications have been made to the prior years' reported amounts to conform to the classifications used in the 2004 consolidated financial statements. These reclassifications were made within the Consolidated Statements of Financial Position, Consolidated Statements of Cash Flows, and Segment Information (note 15), and have no impact on net income.

New Accounting Pronouncements

In March 2004, the Emerging Issues Task Force reached a consensus on issue No. 03-06, *Participating Securities and the Two-Class Method under Financial Accounting Standards Board Statement No. 128. Earnings Per Share* ("EITF 03-06"), which addresses a number of questions regarding the computation of earnings per share by companies that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF 03-06 did not result in a change in the Partnership's calculation of earnings per unit for any of the periods presented because the Partnership had no undistributed net earnings.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

A number of accounting standards, interpretations, Emerging Issues Task Force ("EITF") issues, FASB Staff Positions ("FSP"), Statements of Position ("SOP"), etc. have been proposed by the various standard setting authorities in the United States of America, but have not been finalized. We routinely monitor the activities of standard setting authorities and evaluate the effect the proposed guidance may have on our consolidated financial statements. EITF Issue 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* represents a recent proposal regarding how purchases and sales of inventory between entities in the same line of business that are deemed nonmonetary transactions within the scope of APB 29 are to be recorded. We do not have transactions that fall within the scope of this proposed EITF Issue. However, we cannot determine what, if any, effect a final consensus on this issue may have on our consolidated financial statements due to the preliminary nature of the proposal.

3. ACQUISITIONS

The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of existing assets and through development and acquisition of complementary businesses with similar risk profiles to the Partnership's current business. During 2004, 2003 and 2002 the Partnership completed acquisitions, each of which were accounted for using the purchase method, and the assets acquired and liabilities assumed were recorded at their estimated fair market values as of the date of purchase. The results of operations from these acquisitions are included in earnings from the effective date of the acquisition.

Mid-Continent System

On March 1, 2004, the Partnership acquired crude oil pipeline and storage assets, known as the Mid-Continent system, for $117.0 million, including transaction costs of $2.0 million. The assets acquired serve refineries in the U.S. Mid-Continent from Cushing, Oklahoma and include:

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

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

3. ACQUISITIONS (Continued)

The purchase price and the allocation to assets acquired and liabilities assumed was as follows:

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

Other 2004 Acquisitions

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

On March 1, 2004, the Partnership purchased natural gas transmission and gathering pipeline assets for $13.1 million. The assets, referred to as the "Palo Duro" system, are located in Texas between the Partnership's existing Anadarko and North Texas systems, and are expected to increase natural gas delivery flexibility to the Partnership's customers. The assets purchased include approximately 400 miles of natural gas transmission and gathering pipelines, together with 5,200 horsepower of compression. The purchase price for this acquisition was applied to property, plant and equipment and no goodwill was recorded. The Palo Duro system's results of operations are included in the Partnership's Natural Gas segment from the date of acquisition.

North Texas System

On December 31, 2003, the Partnership acquired natural gas gathering and processing assets in north Texas. The gathering system, referred to as the North Texas system, primarily serves the Fort Worth Basin, including the Barnett Shale producing zone, and is complementary to the Partnership's existing natural gas systems in the area. The assets were purchased for cash of $249.6 million, which includes the buyout of a capital lease of $1.9 million and transaction costs of $1.7 million. The purchase was funded with borrowings under the Partnership's 364-day revolving credit facility and Three-year term credit facility. The value allocated to the assets was determined by an independent appraisal. Goodwill associated with the acquisition was $23.8 million, and is allocated entirely to the Natural Gas segment. Intangible assets acquired of $48.1 million represent the fair value associated with the natural gas supply opportunities present in the Barnett Shale producing zone that will be shipped through the North Texas system and is recorded in the Natural Gas segment. Of the $2.7 million of environmental liabilities assumed, $0.5 million are included in Accounts payable and other and $2.2 million are included in environmental liabilities on the Consolidated Statement of Financial Position as of December 31, 2003.

3. ACQUISITIONS (Continued)

The purchase price and the allocation to assets acquired and liabilities assumed was as follows:

	(dollars in millions)
Purchase Price:	
Cash paid, including transaction costs	$249.6
Allocation of purchase price:	
Current assets	$ 0.4
Property, plant and equipment, including construction in progress	181.0
Intangibles	48.1
Goodwill	23.8
Current liabilities	(1.0)
Environmental liabilities	(2.7)
Total	$249.6

Other 2003 and 2002 Acquisition Transactions

Effective October 17, 2002, the Partnership acquired assets from the General Partner for approximately $875.5 million, including transaction costs of $4.9 million and post-closing adjustments of approximately $50.6 million. In December 2003, the Partnership paid $43.8 million, which includes $2.0 million of interest, in full settlement of post-closing adjustments from the acquisition of acquired assets. The purchase price was therefore reduced by $8.8 million, which is reflected as a decrease to Goodwill in 2003.

Pro Forma Information (unaudited)

The following summarized unaudited Pro Forma Financial information for each of the years ended December 31, 2004 and 2003 assumes the North Texas and Mid-Continent acquisitions described above occurred as of January 1, 2003. These unaudited Pro Forma financial results have been prepared for comparative purposes only. These unaudited Pro Forma financial results may not be indicative of the results that would have occurred if the Partnership had completed the acquisitions as of January 1, 2003 or the results that will be attained in the future.

	Pro Forma Year Ended December 31,	
	2004	2003
	(unaudited dollars in millions; except per unit amounts)	
Operating Revenue	$4,300.0	$3,527.4
Net income	$ 140.6	$ 133.2
Net income per common and i-unit (basic and diluted)	$ 2.07	$ 2.10

4. NET INCOME PER COMMON AND i-UNIT

Net income per common and i-unit is computed by dividing net income, after deducting the General Partner's allocation, by the weighted average number of Class A and B common units and

4. NET INCOME PER COMMON AND i-UNIT (Continued)

i-units outstanding. The General Partner's allocation is equal to an amount based upon its 2% general partner interest, adjusted to reflect an amount equal to incentive distributions earned and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. As there are no dilutive securities outstanding, basic and diluted earnings, per unit amounts are equal. Net income per common and i-unit was determined as follows:

	Year ended December 31,		
	2004	2003	2002
	(dollars and units in millions, except per unit amounts)		
Net income	$138.2	$111.7	$78.1
Allocations to the General Partner:			
Net income allocated to General Partner	(2.8)	(2.2)	(1.1)
Incentive distributions earned	(19.6)	(17.2)	(11.9)
Historical cost depreciation adjustments	(0.1)	(0.2)	(0.1)
	(22.5)	(19.6)	(13.1)
Net income allocable to common units and i-units	$115.7	$ 92.1	$65.0
Weighted average units outstanding	56.1	47.7	36.7
Net income per common and i-unit (basic and diluted)	$ 2.06	$ 1.93	$1.76

5. INVENTORY

Inventory is comprised of the following:

	Year ended December 31,	
	2004	2003
	(dollars in millions)	
Material and supplies	$ 7.1	$ 8.3
Natural gas and liquids inventory	77.4	15.4
	$84.5	$23.7

6. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	Depreciation Rates	December 31, 2004	December 31, 2003
		(dollars in millions)	
Land	—	$ 14.4	$ 12.6
Rights-of-way	0.6%- 5.7%	238.2	222.9
Pipeline	0.6%-14.2%	1,919.8	1,770.1
Pumping equipment, buildings and tanks	0.2%-20.0%	613.0	587.9
Compressors, meters, and other operating equipment	1.5%-20.0%	227.8	167.3
Vehicles, office furniture and equipment	0.1%-33.3%	80.0	69.4
Processing and treating plants	4.0%	95.6	115.2
Construction in progress	—	253.0	66.8
		$3,441.8	$3,012.2
Accumulated depreciation		(663.8)	(546.6)
		$2,778.0	$2,465.6

7. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2004 and 2003 are as follows:

	Liquids	Natural Gas	Marketing	Corporate	Total
		(dollars in millions)			
Balance as of December 31, 2002	$—	$220.7	$20.4	$—	$241.1
Purchase price adjustments	—	(7.7)	—	—	(7.7)
Acquired during the year in conjunction with the North Texas acquisition	—	23.9	—	—	23.9
Balance as of December 31, 2003	—	236.9	20.4	—	257.3
Purchase Price adjustments	—	(0.1)	—	—	(0.1)
Balance as of December 31, 2004	$—	$236.8	$20.4	$—	$257.2

In accordance with SFAS No. 142, the Partnership completed its annual goodwill impairment test using data at June 30, 2004. To estimate the fair value of the reporting units, management made estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures, and net working capital based on assumptions that are consistent with the long-range plans used to manage the business. Based on the results of the impairment analysis, the fair value of each reporting unit was determined to exceed the respective carrying amount, including goodwill. As a result, no goodwill impairment existed in any of its reporting units at June 30, 2004 and no events have occurred or circumstances changed that would, more likely than not, reduce the fair value of its reporting units below the carrying amounts as of December 31, 2004.

8. INTANGIBLES

	December 31,					
	2004			2003		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
	(dollars in millions)					
Customer contracts	$31.1	$(3.3)	$27.8	$31.1	$(2.0)	$29.1
Natural gas supply opportunities	48.1	(1.9)	46.2	48.1	—	48.1
	$79.2	$(5.2)	$74.0	$79.2	$(2.0)	$77.2

Customer contracts are comprised entirely of natural gas purchase and sale contracts and are recorded in the Natural Gas and Marketing segments. Customer contracts are amortized on a straight-line basis over the weighted average useful life of the underlying reserves, which is approximately 25 years.

The natural gas supply opportunities were acquired in conjunction with the North Texas acquisition (see Note 3) and are recorded entirely in the Natural Gas segment. The value of the intangible asset was determined by a third party appraisal and it represents the fair value associated with growth opportunities present in the Barnett Shale producing zone. The natural gas supply opportunities are being amortized over the weighted average estimated useful life of the underlying reserves, which is approximately 25 years.

The aggregate amortization expense for the years ended December 31, 2004, 2003 and 2002, were $3.2 million, $1.3 million, and $0.7 million, respectively. The estimated amortization expense for each year through December 31, 2009 is $3.2 million.

9. DEBT

The Partnership's debt consisted of the following as of the dates indicated:

		December 31,			
		2004		2003	
	Maturity	Rate	Dollars	Rate	Dollars
		(dollars in millions)			
First Mortgage Notes	2011	9.15%	$ 217.0	9.15%	$ 248.0
Senior Notes	2009-2034	5.66%	1,198.4	6.20%	698.8
Three-year Term Credit Facility	2007	2.05%	175.0	1.84%	240.0
Senior Credit Facility	2004	—	—	1.90%	215.0
			$1,590.4		$1,401.8
Current maturities and short-term debt			(31.0)		(246.0)
Long-term debt			$1,559.4		$1,155.8

9. DEBT (Continued)

First Mortgage Notes

The First Mortgage Notes ("Notes") are collateralized by a first mortgage on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. Property, plant and equipment attributable to the Lakehead Partnership is $1,408.9 million and $1,400.5 million as of December 31, 2004 and 2003, respectively. The Notes contain various restrictive covenants applicable to the Partnership, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. The Partnership believes these restrictions will not negatively impact its ability to finance future expansion projects. Under the Note Agreements, the Partnership cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (see Note 10) for the immediately preceding calendar quarter. If the notes were to be paid prior to their stated maturities, the Note agreements provide for the payment of a redemption premium by the Partnership.

Under the terms of the First Mortgage Notes, the Partnership is required to establish, at the end of each quarter, a debt service reserve amount. This reserve includes an amount equal to 50% of the prospective First Mortgage Note interest payments for the immediately following quarter and an amount for First Mortgage Note sinking fund repayments. At December 31, 2004 and 2003, there was no required debt service reserve, as all required interest and sinking fund payments had been made.

Senior Notes

On January 9, 2004, the Partnership issued $200.0 million in aggregate principal amount of its 4.00% Senior Notes due 2009. The Partnership used the proceeds of approximately $198.3 million, net of expenses of approximately $1.6 million, to repay a portion of its outstanding debt under bank credit facilities.

On December 3, 2004, the Partnership issued $200.0 million in aggregate principal amount of its 5.35% Senior Notes due 2014 and $100.0 million in aggregate principal amount of its 6.30% Senior Notes due 2034. The Partnership used the proceeds of approximately $297.1 million, net of expenses of approximately $2.6 million, to repay a portion of the amounts outstanding under bank credit facilities.

9. DEBT (Continued)

All of the Senior Notes pay interest semi-annually and have varying maturities and terms as outlined below. The Senior Notes do not contain any covenants restricting the issuance of additional indebtedness and rank equally with all of our other existing and future unsubordinated indebtedness.

Senior Notes	Interest Rate	December 31, 2004	December 31, 2003
		(dollars in millions)	
Notes maturing in 2009	4.00%	$ 200.0	$ —
Notes maturing in 2012	7.90%	100.0	100.0
Notes maturing in 2013	4.75%	200.0	200.0
Notes maturing in 2014	5.35%	200.0	—
Notes maturing in 2018	7.00%	100.0	100.0
Notes maturing in 2028	7.125%	100.0	100.0
Notes maturing in 2033	5.95%	200.0	200.0
Notes maturing in 2034	6.30%	100.0	—
		$1,200.0	$700.0
Unamortized Discount		(1.6)	(1.2)
		$1,198.4	$698.8

Bank Credit Facilities

On April 26, 2004, the Partnership amended its unsecured multi-year revolving credit facility and terminated its existing 364-day revolving credit facility, each of which was originally entered into in January 2003. The amended facility consists of a $600.0 million Three-year term credit facility, which matures in 2007. Interest is charged on amounts drawn under this facility at a variable rate equal to the Base Rate or a Eurodollar rate as defined in the facility agreement. In the case of Eurodollar rate loans, an additional margin is charged which varies depending on the Partnership's credit rating and the amounts drawn under the facility. A facility fee is payable on the entire amount of the facility whether or not drawn. The facility fee varies depending on the Partnership's credit rating. As of December 31, 2004, the facility fee was 0.175%. The Credit Facility contains restrictive covenants that require the Partnership to maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 5.25 times for eighteen months until September 2005, decreasing to 5.00 times thereafter, as described in the Credit Facility. At December 31, 2004, the interest coverage ratio was approximately 4.3 and the leverage ratio was approximately 4.2. The Credit Facility also places limitations on the amount of debt that may be incurred directly by the Partnership's subsidiaries. Accordingly, it is expected that the Partnership will provide debt financing to its subsidiaries as required and as of December 31, 2004 the Partnership's subsidiaries had no amounts outstanding under this facility. As of December 31, 2004, the Partnership has drawn $175.0 million on the Credit Facility at a weighted average interest rate of 2.1%. Additionally, the Partnership has outstanding letters of credit totaling $39.6 million that primarily serve to support the Partnership's derivative transactions.

9. DEBT (Continued)

Interest

In 2004, 2003, and 2002, interest expense is net of amounts capitalized of $2.1 million, $2.2 million, and $7.9 million, respectively. In 2004, 2003, and 2002, total interest paid was $73.9 million, $69.1 million, and $58.8 million, respectively.

Maturities of External Third Party Debt

The scheduled maturities of outstanding external third party debt, excluding the market value of interest rate swaps, at December 31, 2004, are summarized as follows:

	(dollars in millions)
2005	$ 31.0
2006	31.0
2007	206.0
2008	31.0
2009	231.0
Thereafter	1,060.4
Total	**$1,590.4**

10. PARTNERS' CAPITAL

The Partnership's ownership is comprised of a 2% general partner interest and 98% limited partner interests. The limited partner ownership in the Partnership is comprised of Class A common units, Class B common units and i-units. The limited partners have limited rights of ownership as provided for under the Partnership Agreement and, as discussed below, participate in the Partnership's distributions. The General Partner manages the operations of the Partnership, subject to a Delegation of Control Agreement with Enbridge Management, and participates in the Partnership's distributions, including certain incentive income distributions.

Class A common units

In September 2004, the Partnership issued 3.68 million Class A common units at $47.90 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $168.6 million. Proceeds from this offering were used to reduce borrowings under the Partnership's Senior Credit Facility by approximately $165.0 million. In addition, the General Partner contributed $3.6 million to the Partnership to maintain its 2% general partner interest in the Partnership.

In December 2003, the Partnership issued 5.0 million Class A common units at $50.30 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $240.3 million. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility by approximately $105.0 million, to reduce borrowings under the Three-year term credit facility of approximately $100.0 million and to pay the December 15, 2003 sinking fund payment of $31.0 million on the First Mortgage Notes. In addition to the proceeds generated from the unit issuance, the General Partner contributed $5.1 million to the Partnership to maintain its 2% general partner interest in the Partnership.

10. PARTNERS' CAPITAL (Continued)

In January 2004, the Partnership issued an additional 450,000 Class A common units pursuant to the underwriters' exercise of the over-allotment option as part of the December 2003 Class A common unit issuance, resulting in additional proceeds to the Partnership, net of underwriters' fees and discounts, commissions and issuance expense, of approximately $21.6 million. The proceeds from the over-allotment were used to reduce the 364-day credit facility. In addition to the proceeds generated from the unit issuance, the General Partner contributed $0.4 million to the Partnership to maintain its 2% general partner interest in the Partnership.

In May 2003, the Partnership issued 3.85 million Class A common units at $44.79 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $165.5 million. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility of approximately $102.4 million and an affiliate loan from Enbridge (U.S.) Inc. by $63.1 million. In addition to the proceeds generated from the unit issuance, the General Partner contributed $3.5 million to the Partnership to maintain its 2% general partner interest in the Partnership.

Class B common units

At December 31, 2004 and 2003, the Partnership had 3,912,750 Class B common units outstanding, which are held entirely by the General Partner. The Class B common units have rights similar to the Class A common units except that they are not eligible for trading on the NYSE.

i-units

The i-units are a separate class of limited partner interests in the Partnership. All of the i-units are owned by Enbridge Management and are not publicly traded.

Enbridge Management, as the owner of the i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

- Any proposed action that would cause the Partnership to be treated as a corporation for U.S. federal income tax purposes;
- Amendments to the Partnership Agreement that would have a material adverse effect on the holders of the i-units, unless, under the Partnership Agreement, the amendment could be made by the general partner of the Partnership without a vote of holders of any class of units;
- The removal of the general partner of the Partnership and the election of a successor general partner; and
- The transfer by the general partner of the Partnership of its general partner interest to a non-affiliated person that requires a vote of holders of units under the Partnership Agreement and the admission of that person as a general partner of the Partnership.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management's shares vote or refrain from voting their shares. Furthermore, under the terms of the Partnership Agreement, the Partnership agrees that it will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

10. PARTNERS' CAPITAL (Continued)

Distributions Paid

The Partnership Agreement requires that the Partnership distribute 100% of its "Available Cash", which is generally defined in the Partnership Agreement as the sum of all cash receipts and net additions to reserves for future requirements less cash disbursements and amounts retained by the Partnership. The reserves are retained to provide for the proper conduct of the Partnership business and as necessary to comply with the terms of any agreement or obligation of the Partnership (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). The amounts retained by the Partnership are the cash amount in respect to the i-unit distribution plus an amount equal to 2% of the i-unit distribution. The distributions are made to its partners approximately 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

The General Partner is granted discretion by the Partnership Agreement, which discretion has been delegated to Enbridge Management, subject to the approval of the General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines the quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions by the Partnership of its Available Cash generally are made 98.0% to the Class A and B common unitholders and the i-unitholder and 2.0% to the General Partner. The Partnership will not distribute the cash related to the i-units, but instead, will distribute additional i-units such that the cash is retained and used in the Partnership's business. Further, the Partnership retains an additional amount equal to 2.0% of the i-unit distribution from the General Partner to maintain the 2% general partner interest in the Partnership. Distributions are subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions to the unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15.0%, 25.0% and 50.0% of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per Class A and B common units and i-units, respectively.

Typically, the General Partner and owners of common units will receive distributions in cash. Enbridge Management, as the delegate of the General Partner under the Delegation of Control Agreement, computes the amount of the Partnership's available cash. Enbridge Management, as owner of the i-units, however, does not receive distributions in cash. Instead, each time that the Partnership makes a cash distribution to the General Partner and the holders of its common units, the number of i-units owned by Enbridge Management and the percentage of total units in the Partnership owned by Enbridge Management will increase automatically under the provisions of the Partnership's partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's shares and voting shares that are then outstanding. The amount of this increase per i-unit is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-day period immediately preceding the ex-dividend date for Enbridge Management's shares. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

10. PARTNERS' CAPITAL (Continued)

The following table sets forth the distributions, as approved by the Board of Directors for each period in the years ended December 31, 2004, 2003 and 2002.

Distribution Declaration Date	Distribution Payment Date	Ex-Distribution Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit holders[1]	Retained from General Partner[2]	Distribution of Cash
				(dollars in millions, except per unit amounts)			
2004							
October 22, 2004	November 12, 2004	November 1, 2004	$0.925	$ 60.7	$ 9.9	$0.2	$ 50.6
July 22, 2004	August 13, 2004	August 2, 2004	0.925	56.6	9.6	0.2	46.8
April 26, 2004	May 14, 2004	May 5, 2004	0.925	56.5	9.5	0.2	46.8
January 22, 2004	February 13, 2004	February 2, 2004	0.925	56.3	9.3	0.2	46.8
				$230.1	$38.3	$0.8	$191.0
2003							
October 22, 2003	November 14, 2003	November 4, 2003	$0.925	$ 50.5	$ 9.2	$0.2	$ 41.1
July 23, 2003	August 14, 2003	July 31, 2003	0.925	50.3	8.9	0.2	41.2
April 24, 2003	May 15, 2003	April 30, 2003	0.925	46.1	8.7	0.2	37.2
January 23, 2003	February 14, 2003	January 31, 2003	0.925	46.0	8.6	0.2	37.2
				$192.9	$35.4	$0.8	$156.7
2002							
October 24, 2002	November 14, 2002	November 5, 2002	$ 0.90	$ 44.2	$ 8.1	$0.2	$ 35.9
July 22, 2002	August 14, 2002	August 5, 2002	0.90	34.8	—	—	34.8
April 25, 2002	May 15, 2002	May 3, 2002	0.90	34.8	—	—	34.8
January 24, 2002	February 14, 2002	February 5, 2002	0.90	32.6	—	—	32.6
				$146.4	$ 8.1	$0.2	$138.1

(1) The Partnership issued 840,239, 833,515 and 228,654 i-units to Enbridge Energy Management, L.L.C., the sole owner of the Partnership's i-units, during 2004, 2003 and 2002, respectively, in lieu of cash distributions.

(2) The Partnership retains an amount equal to 2% of the i-unit distribution from the General Partner in respect of its 2% general partner interest in the i-units.

11. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management and administrative, operations and workforce related services to the Partnership. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including the Partnership. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. There is no profit or margin for these services charged by Enbridge to its affiliates.

The portion of direct workforce costs associated with the management and administrative services provided at the Partnership's Houston office and the operating and administrative services provided to support the Partnership's facilities across the United States, are charged from Enbridge and its affiliates to the Partnership.

Certain of the Partnership's operating activities associated with its Liquids segment are provided by Enbridge Pipelines Inc., a subsidiary of Enbridge, as the majority of these pipeline systems form one contiguous system with the Enbridge system in Canada. These services include control center operations, facilities management, shipper services, pipeline integrity management and other related activities. The costs to provide these services are allocated to the Partnership from Enbridge Pipelines Inc., a subsidiary of Enbridge, based on an appropriate allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent and miles of pipe. The Partnership also receives costs associated with control center services for some of its Natural Gas assets from another affiliate of Enbridge.

Enbridge also allocates management and administrative costs to the Partnership pursuant to the Partnership's partnership agreement and related services agreements. These costs are allocated to the Partnership based on an appropriate allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent and headcount.

During 2004, 2003 and 2002, the Partnership incurred the following costs related to these services, which are included in operating and administrative expenses.

	Year ended December 31,		
	2004	2003	2002
	(dollars in millions)		
Direct workforce costs	$101.7	$75.4	$51.2
Liquids /Natural Gas operating costs	14.0	9.6	6.5
Allocated management and administrative costs, including insurance	17.2	14.2	13.5
	$132.9	$99.2	$71.2

Natural Gas Sales and Purchases

The Partnership purchases natural gas from third parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale. Included in the results for the twelve months ending December 31, 2004, 2003 and 2002, are operating revenues of $23.6 million, $30.6 million, and $4.6 million, respectively, related to these sales.

The Partnership also purchases natural gas from Enbridge and its affiliates for sale to third parties at market prices on the date of purchase. Included in the results for the twelve months ending December 31, 2004, 2003 and 2002, are cost of natural gas expenses of $6.9 million, $1.2 million and $0.1 million, respectively, relating to these purchases.

Affiliate Notes

The Partnership has a note payable with an affiliate of Enbridge that totaled $142.1 million and $133.1 million at December 31, 2004 and 2003, which matures in 2007. The interest rate is 6.60% as of December 31, 2004 and 2003.

Interest expense related to affiliate notes totaled $9.0 million, $16.1 million, and $4.6 million in 2004, 2003, and 2002, respectively.

For the year ended December 31, 2004 and 2003 we converted interest payable related to loans from the General Partner and affiliates in the amount of $9.0 million and $16.1 million, respectively, into long-term debt to the General Partner and affiliates.

Incentive and Partnership Distributions

Pursuant to our partnership agreement, the General Partner owns an effective 2% general partner ownership interest in the Partnership. The General Partner received incentive distributions for the years ended December 31, 2004, 2003 and 2002 of $22.9 million, $19.2 million, and $13.3 million, respectively.

As of December 31, 2004 and 2003, the General Partner also owned 3,912,750 Class B common units, representing 6.5% and 7.1% ownership, respectively in the Partnership. The General Partner received cash distributions related to its ownership of Class B common units for the years ended December 31, 2004, 2003 and 2002 of $14.4 million, $14.5 million and $14.1 million, respectively.

Conflicts of Interest

Through a Delegation of Control Agreement with the General Partner and the Partnership, Enbridge Management makes all decisions relating to the management and control of the Partnership's business. The General Partner owns the voting shares of Enbridge Management and elects all of Enbridge Management's directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines Inc., owns all the common stock of the General Partner. Some of the General Partner's officers and directors are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of the Partnership's unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, the General Partner, Enbridge and the Partnership. The partnership agreement and Delegation of Control Agreement for the Partnership and its subsidiaries contain provisions that allow Enbridge Management to take into account the interest of parties in addition to the Partnership in resolving conflicts of interest, thereby limiting its fiduciary duties to the Partnership's unitholders, as well as provisions that may restrict the remedies available to unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

Enbridge Management

Pursuant to the Delegation of Control Agreement between Enbridge Management, the General Partner and the Partnership, and the Partnership's partnership agreement, all expenses relating to

Enbridge Management are paid by the Partnership. This includes Texas franchise taxes and any other foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

12. ENVIRONMENTAL LIABILITIES

The Partnership is subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid and gas pipeline operations and the Partnership could, at times, be subject to environmental cleanup and enforcement actions. The Partnership manages this environmental risk through appropriate environmental policies and practices to minimize any impact. To the extent that the Partnership is unable to recover environmental liabilities associated with the Lakehead system assets, to the extent not recovered through insurance, the General Partner has agreed to indemnify the Partnership from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to the Partnership in 1991. This excludes any liabilities resulting from a change in laws after such transfer. The Partnership continues to voluntarily investigate past leak sites on its systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date, no material environmental risks have been identified.

In connection with the Partnership's acquisition of the Midcoast systems in October 2002, the General Partner has agreed to indemnify the Partnership and other related persons for certain environmental liabilities of which the General Partner has knowledge and which it did not disclose. The General Partner will not be required to indemnify the Partnership until the aggregate liabilities, including environmental liabilities, exceed $20.0 million, and the General Partner's aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, $150.0 million. The Partnership will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed.

As of December 31, 2004 and 2003, the Partnership has recorded $3.6 million and $2.6 million in current liabilities and $5.3 million and $7.9 million, respectively, in long-term liabilities primarily to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of its liquids and natural gas assets.

In March 2004, the Partnership reduced its long-term environmental liabilities by $2.0 million related to certain of its Natural Gas segment assets. During the time that these assets have been owned by the Partnership, since October 2002, Management has completed a review of the affected sites and determined that suspected contamination is less significant than originally estimated. This assessment was based upon information gathered during the ownership period, existing technology, presently enacted laws and regulations and prior experience in remediating contaminated sites for similar assets.

13. COMMITMENTS AND CONTINGENCIES

Oil and Gas in Custody

The Partnership's Liquids assets transport crude oil and natural gas liquids owned by its customers for a fee. The volume of liquid hydrocarbons in the Partnership's pipeline system at any one time approximates 25 million barrels, virtually all of which is owned by the Partnership's customers. Under terms of the Partnership's tariffs, losses of crude oil not resulting from direct negligence of the Partnership may be apportioned among its customers. In addition, the Partnership maintains adequate property insurance coverage with respect to crude oil and natural gas liquids in the Partnership's custody.

Approximately 50% of the natural gas volumes on the natural gas assets are transported for customers on their contract, with the remaining 50% purchased by the Partnership and sold to third parties downstream of the purchase point. At any point in time, the value of customers' natural gas in custody of the natural gas systems is not material to the Partnership.

Rate Refunds

On October 8, 2004, the FERC issued an Order on Remand ("Remand Order") relating to initial rates on the Partnership's Kansas Pipeline System ("KPC") for the period of time between December 1997 and November 2002. The Partnership acquired KPC on October 17, 2002. The Remand Order was issued in response to a United States Court of Appeals ruling in August 2003 requiring the FERC to address the issue of appropriate rate refunds, if any, with respect to KPC's initial rates. In the Remand Order, the FERC found that the proper initial rates are lower than the rates previously charged to customers pending resolution of this contested rate case. In accordance with the FERC's findings, any difference between what was collected and these revised initial Section 7 rates for the period of time between December 1997 and November 2002, plus interest compounded quarterly, is subject to refund.

Refunds to our customers were made in January 2005 pursuant to a refund plan agreed upon with customers and approved by the FERC. Our Consolidated Statements of Income for the year ended December 31, 2004, includes a charge of approximately $13.6 million for the rate refunds and interest. The rate refunds relate almost entirely to a time period prior to the Partnership's ownership of KPC.

Right-of-Way

The Partnership, as part of its pipeline construction process, must obtain certain right-of-way agreements from landowners whose property the pipeline will cross. Right-of-way agreements that the Partnership buys are capitalized as part of Property, Plant and Equipment. Right-of-way agreements that are leased from a third party are expensed. The Partnership recorded expenses for the leased right-of-way agreements of $1.8 million, $1.4 million, and $1.2 million during 2004, 2003, and 2002, respectively.

Legal Proceedings

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

Future Minimum Commitments

As of December 31, 2004, the future minimum commitments having remaining non-cancelable terms in excess of one year are as follows:

Future Minimum Commitments	2005	2006	2007	2008	2009	Thereafter	Total
			(dollars in millions)				
Power and other purchase commitments	$ 55.7	$ 3.1	$ —	$ —	$—	$ —	$ 58.8
Other operating leases	5.7	5.6	3.4	3.4	3.3	1.1	22.5
Right-of-way[(1)]	1.9	1.8	1.8	1.8	1.7	45.0	54.0
Product purchase obligations[(2)]	50.9	50.0	37.7	30.3	.3	2.5	171.7
Service contract obligations[(3)]	6.3	6.4	5.6	3.3	1.6	—	23.2
Total	$120.5	$66.9	$48.5	$38.8	$6.9	$48.6	$330.2

(1) Right-of-way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipeline systems, which has been estimated to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2009.

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

(3) The transportation service obligations represent the minimum payment amounts for firm transportation capacity reserved by the Partnership on third-party pipelines.

14. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying amounts of cash equivalents approximate fair value because of the short term to maturity of these investments.

Based on the borrowing rates currently available for instruments with similar terms and remaining maturities, the carrying value of borrowings under the credit facilities approximates fair value.

At December 31, 2004 and 2003, the fair value of the First Mortgage Notes approximates $256.8 million and $303.0 million and the fair value of the Senior Notes approximates $1,260.7 million and $739.0 million, respectively. Due to defined contractual make-whole arrangements, refinancing of the First Mortgage Notes and Senior Notes would not result in a material financial benefit to the Partnership.

The fair value of derivative financial instruments reflects the Partnership's best estimate and is based on the Partnership's techniques or models to estimate market values. These modeling techniques require the Partnership to make estimations of future prices, price correlation and market volatility and liquidity. The estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating positions in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of counter parties and operational risk.

The Partnership enters into floating rate to fixed rate interest rate swaps to manage the effect of future interest rate movements on its interest costs. The Partnership also enters fixed rate to floating rate interest rate swaps to manage the fair value of debt issuances. The following table summarizes the interest rate financial derivatives outstanding at December 31:

	Notional Principal	Partnership Pays	Partnership Receives	Maturity Date	Fair Value 2004	Fair Value 2003
					(dollars in millions)	
Fixed rate interest rate swaps:	$ 50.0	1.31%	LIBOR	October 6, 2004	$ —	$ —
	$ 50.0	1.31%	LIBOR	October 7, 2004	$ —	$ —
	$ 25.0	1.44%	LIBOR	December 29, 2004	$ —	$ —
	$ 25.0	1.45%	LIBOR	December 24, 2004	$ —	$ —
	$ 50.0	4.37%	LIBOR	June 1, 2013	$(0.4)	$ —
	$ 50.0	4.3425%	LIBOR	June 1, 2013	$(0.3)	$ —
	$ 25.0	4.31%	LIBOR	June 1, 2013	$(0.2)	$ —
Floating rate interest rate swaps:						
	$ 50.0	LIBOR-21bps	4.75%	June 1, 2013	$ 1.8	$1.7
	$ 50.0	LIBOR-21bps	4.75%	June 1, 2013	$ 1.8	$1.7
	$ 25.0	LIBOR-25bps	4.75%	June 1, 2013	$ 1.0	$0.8
Treasury Lock:	$104.0	3.19%	N/A	January 30, 2004	$ —	$1.0

The fixed rate interest rate swaps and the treasury lock meet the criteria for hedge accounting and are accounted for as cash flow hedges.

The floating rate interest rate swaps meet the criteria for hedge accounting and are accounted for as fair value hedges.

Commodity Price Risk

The earnings and cash flows of the Partnership are sensitive to changes in the prices of natural gas, NGLs, condensate, and to fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within the Natural Gas and Marketing segments. To mitigate the volatility of cash flows, the Partnership enters into derivative financial instruments to manage the purchase and sales prices of the commodities. The majority of the Partnership's commodity derivative transactions qualify for hedge accounting under SFAS No. 133 and are accounted for as cash flow hedges.

Natural Gas

Natural gas derivative transactions are entered into by the Partnership in order to hedge the forecasted purchases or sales of natural gas. The following table details the outstanding derivatives including unrealized gains (losses) at December 31:

System	Maturity Dates	Notional MMBtu	Fair Value 2004	Fair Value 2003
			(dollars in millions)	
East Texas system	2005-2012	62,102,000	$(100.8)	$(64.8)
North Texas system	2005-2008	6,390,000	$ 4.0	$ —
Midcoast system	2005-2007	7,374,000	$ —	$ (0.7)
Marketing	2005-2008	385,960,000	$ (11.6)	$ 2.0

A limited number of natural gas derivative transactions, which mitigate economic exposures arising from underlying natural gas purchases and sales, do not qualify for hedge accounting treatment under SFAS No. 133. As such, the change in fair market value of these derivative instruments is recorded in the income statement in the cost of natural gas expense.

Natural Gas Liquids

NGL derivative transactions are entered into by the Partnership to hedge the forecasted sales of NGLs. The following table details the outstanding derivatives at December 31:

System	Maturity Date	Notional Barrels	Fair Value 2004	Fair Value 2003
		(in millions)	(dollars in millions)	
East Texas System	2005-2007	2.2	$(9.9)	$(3.2)
Midcoast System	2005-2007	1.8	$(2.0)	$(0.2)
North Texas System	2005-2008	2.7	$(6.7)	$(1.1)

Hedge Instrument Ineffectiveness

The changes in the market value of natural gas derivative instruments that are attributable to hedge ineffectiveness are included in the cost of natural gas expense in the Consolidated Statements of Income in the period in which they occur. The following table sets forth the liabilities recorded in the Consolidated Statements of Financial Position for the ineffective portion of our hedges by segment at December 31:

	2004	2003
	(dollars in millions)	
Natural Gas	$(1.1)	$ —
Marketing	(2.4)	(0.3)
	$(3.5)	$(0.3)

Other

The Partnership estimates that approximately $36.5 million of the Accumulated Other Comprehensive Loss, which represents unrecognized net losses on derivative activities at December 31, 2004, will be reclassified into earnings during the next twelve months.

At December 31, 2004, no material credit risk exposure existed as the Partnership enters into financial instruments only with credit worthy institutions that possess investment grade ratings.

The Partnership's hedging activities are included at the fair values in the Consolidated Statements of Financial Position as follows:

	December 31, 2004	December 31, 2003
	(dollars in millions)	
Accounts receivable, trade and other	$ 8.2	$ 3.1
Other assets, net	10.1	4.0
Accounts payable and other	(44.7)	(41.4)
Deferred credits	(93.4)	(23.9)
	$(119.8)	$(58.2)

15. SEGMENT INFORMATION

The Partnership's business is divided into operating segments, defined as components of the enterprise about which financial information is available and evaluated regularly by the Partnership's Chief Operating Decision Maker in deciding how to allocate resources to an individual segment and in assessing performance of the segment.

The Partnership's reportable segments are based on the type of business activity and management control. Each segment is managed separately because each business requires different operating strategies. The Partnership has three reportable business segments, Liquids, Natural Gas and Marketing. Each segment uses accounting policies as described in the Summary of Significant Accounting Policies (see Note 2).

15. SEGMENT INFORMATION (Continued)

The following table presents certain financial information relating to the Partnership's business segments as of and for the years ended December 31, 2004, 2003 and 2002.

	As of and for the Year Ended December 31, 2004				
	Liquids	Natural Gas	Marketing	Corporate(1)	Total
	(dollars in millions)				
Total revenues	$ 409.3	$2,890.1	$2,686.9	$ —	$5,986.3
Less: Intersegment revenue	—	1,570.2	124.4	—	1,694.6
Operating revenues	409.3	1,319.9	2,562.5	—	4,291.7
Cost of natural gas	—	1,031.8	2,555.3	—	3,587.1
Operating and administrative	128.9	138.3	3.4	3.5	274.1
Power	72.8	—	—	—	72.8
Depreciation and amortization	68.5	51.7	0.2	0.1	120.5
Operating income	$ 139.1	$ 98.1	$ 3.6	$ (3.6)	$ 237.2
Interest expense	—	—	—	(88.4)	(88.4)
Rate refunds	—	—	—	(13.6)	(13.6)
Other income (expense)	—	—	—	3.0	3.0
Minority interest	—	—	—	—	—
Net income	$ 139.1	$ 98.1	$ 3.6	$(102.6)	$ 138.2
Total assets	$1,639.8	$1,717.2	$ 313.7	$ 92.3	$3,763.0
Capital expenditures (excluding acquisitions)	$ 81.9	$ 197.4	$ 0.3	$ 9.2	$ 288.8

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2003				
	Liquids	Natural Gas	Marketing	Corporate(1)	Total
	(dollars in millions)				
Total revenues	$ 344.2	$2,079.8	$1,984.9	$ —	$4,408.9
Less: Intersegment revenue	—	1,121.3	115.3	—	1,236.6
Operating revenues	344.2	958.5	1,869.6	—	3,172.3
Cost of natural gas	—	754.9	1,857.8	—	2,612.7
Operating and administrative	104.1	102.3	2.2	3.2	211.8
Power	56.1	—	—	—	56.1
Depreciation and amortization	59.5	37.7	0.2	—	97.4
Operating income	$ 124.5	$ 63.6	$ 9.4	$ (3.2)	$ 194.3
Interest expense	—	—	—	(85.0)	(85.0)
Rate refunds	—	—	—	—	—
Other income (expense)	—	—	—	2.4	2.4
Minority interest	—	—	—	—	—
Net income	$ 124.5	$ 63.6	$ 9.4	$(85.8)	$ 111.7
Total assets	$1,511.2	$1,490.5	$ 189.6	$ 40.5	$3,231.8
Capital expenditures (excluding acquisitions)	$ 69.3	$ 55.4	$ 0.1	$ 4.5	$ 129.3

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

15. SEGMENT INFORMATION (Continued)

	As of and for the Year Ended December 31, 2002				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
	(dollars in millions)				
Total revenues	$ 334.3	$ 732.4	$267.9	$ —	$1,334.6
Less: Intersegment revenue	—	138.7	10.4	—	149.1
Operating revenues	334.3	593.7	257.5	—	1,185.5
Cost of natural gas	—	515.5	255.2	—	770.7
Operating and administrative	104.7	39.0	0.5	—	144.2
Power	52.7	—	—	—	52.7
Depreciation and amortization	64.8	15.1	—	—	79.9
Operating income	$ 112.1	$ 24.1	$ 1.8	$ —	$ 138.0
Interest expense	—	—	—	(59.2)	(59.2)
Rate refunds	—	—	—	—	—
Other income (expense)	—	—	—	(0.2)	(0.2)
Minority interest	—	—	—	(0.5)	(0.5)
Net income	$ 112.1	$ 24.1	$ 1.8	$(59.9)	$ 78.1
Total assets	$1,528.0	$1,169.6	$137.3	$ —	$2,834.9
Capital expenditures (excluding acquisitions)	$ 201.8	$ 12.9	$ —	$ —	$ 214.7

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

16. SUBSEQUENT EVENTS

Cash Distribution

On January 24, 2005, the Partnership's Board of Directors declared a distribution payable on February 14, 2005, to unitholders of record as of February 3, 2005, of our available cash of $61.0 million at December 31, 2004, or $0.925 per common unit. Of this distribution, $50.7 million was paid in cash, $10.1 million was distributed in i-units to i-unit holders and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

Acquisition

On November 18, 2004, the Partnership entered into a definitive agreement to acquire natural gas gathering and processing assets in north Texas for approximately $165.0 million in cash, excluding normal closing adjustments. The asset purchase closed with an effective date of January 1, 2005. We funded the acquisition with borrowings under our existing credit facilities.

The assets purchased primarily serve areas of the Fort Worth Basin, which are mature, but experiencing minimal production decline rates. The assets include approximately 2,200 miles of gas gathering pipelines and four processing plants with aggregate processing capacity of 121 million cubic feet of natural gas per day.

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the gas and then selling the natural gas liquids and residue gas streams. The assets

16. SUBSEQUENT EVENTS (Continued)

will be included in the Partnership's Natural Gas segment and will become part of our North Texas system. The purchase price was allocated entirely to the fixed asset purchased, and there was no goodwill recorded.

Class A common unit issuance

In February 2005, we issued 2,506,500 million Class A common units at $49.875 per unit, which generated proceeds, net of offering expenses, of approximately $124.9 million. Proceeds from this offering were used to repay borrowings under our Three-year term credit facility. In addition, the General Partner contributed $2.7 million to the Partnership to maintain its 2% general partner interest in the Partnership.

17. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
	(dollars in millions, except per unit amounts)				
2004 Quarters					
Operating revenue	$982.5	$969.7	$1,004.8	$1,334.7	$4,291.7
Operating income	$ 52.6	$ 58.0	$ 61.6	$ 65.0	$ 237.2
Net income	$ 33.1	$ 35.9	$ 27.6	$ 41.6	$ 138.2
Net income per common and i-unit[(1)]	$ 0.50	$ 0.56	$ 0.39	$ 0.61	$ 2.06
2003 Quarters					
Operating revenue	$896.1	$755.3	$ 760.5	$ 760.4	$3,172.3
Operating income	$ 53.9	$ 43.1	$ 45.0	$ 52.3	$ 194.3
Net income	$ 32.6	$ 23.3	$ 23.5	$ 32.3	$ 111.7
Net income per common and i-unit[(1)]	$ 0.62	$ 0.39	$ 0.38	$ 0.54	$ 1.93

(1) The General Partner's allocation of net income has been deducted before calculating net income per common and i-unit.