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, 2003

OR

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

For the transition period from ______________ to ______________

Commission File Number: 1-10934

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

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

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

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

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

Title of each class	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, 2003, was $1,683,394,439.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

TABLE OF CONTENTS

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 the ability of the Partnership to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Items 1. & 2. Business and Properties—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 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
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
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
General Partner	Enbridge Energy Company, Inc., general partner of the Partnership
HCA	High consequence area
Hinshaw pipeline	An intrastate pipeline that receives 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
KPC	Kansas Pipeline Company
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
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.
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
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
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership
Partnership	Enbridge Energy Partners, L.P. and subsidiaries
PPIFG-1	Producer Price Index for Finished Goods minus 1%
PSA	Pipeline Safety Act
RCRA	Resource Conservation and Recovery Act

RSPA	Research and Special Programs Administration
SAGD	Steam Assisted Gravity Drainage
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. & 2.—Business & Properties

OVERVIEW

The Partnership is a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation assets and natural gas gathering, treating, processing, transmission and marketing assets in the United States. The Class A common units of the Partnership are traded on the NYSE under the symbol "EEP."

The Partnership was 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. Since the Partnership's initial public offering in 1991, it has increased its quarterly cash distribution by 57% from $0.59 per unit to the current quarterly rate of $0.925 per unit.

The Partnership's 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 7.1% limited partner interest, in the form of 3,912,750 Class B common units in the Partnership. The remaining 90.9% limited partner interest is represented by a 72.7% ownership interest of 40,166,134 publicly traded Class A common units and an 18.2% ownership interest of 10,062,170 i-units, which are wholly-owned by Enbridge Management.

Enbridge Management is a Delaware limited liability company that was formed on May 14, 2002. Enbridge Management's shares represent limited liability company interests and are traded on the NYSE under the symbol "EEQ." Its principal asset is its 18.2% limited partnership interest in the Partnership through its ownership of i-units. Enbridge Management's principal activity is managing the business and affairs of the Partnership and its subsidiaries. Under a Delegation of Control Agreement, the General Partner delegated substantially all of its power and authority to manage the business and affairs of the Partnership 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.

Since May 2001, the Partnership has diversified its operations both geographically and by industry. The North Dakota system, acquired in May 2001, connects to the Partnership's Lakehead system and accessed a different crude oil supply basin in North Dakota and Montana. The East Texas system, acquired in November 2001, was the Partnership's first entry into the natural gas gathering and processing business and diversified the geographic focus of the Partnership to include the southern United States. In October 2002, the Partnership continued its diversification through the acquisition of the Midcoast system, which included natural gas gathering, treating, processing, transmission and marketing activities located in the southern United States. On December 31, 2003, the Partnership acquired the North Texas system, a natural gas gathering and processing business in Texas.

AVAILABLE INFORMATION

The Partnership files annual, quarterly and other reports and information with the SEC under the Exchange Act. You may read and copy any materials that the Partnership files 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 the Partnership.

The Partnership also makes available free of charge on or through its Internet website *http://www.enbridgepartners.com* its 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 the Partnership electronically files such material with the SEC.

BUSINESS STRATEGY

The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of existing assets and through the development and acquisition of complementary businesses with risk profiles similar to the Partnership's current business.

A number of developments in 2003 strengthened the Partnership's position as a crude oil carrier into the U.S. Mid-Continent. The Partnership continues to expand the Lakehead system's capacity through the construction of Terrace and the complementary expansion of pipeline facilities in the Chicago area. CAPP had requested these expansions, in anticipation of future growth in crude oil production from the prolific Alberta oil sands. In September 2003, Enbridge purchased a crude oil pipeline that currently flows from Cushing, Oklahoma to Chicago, Illinois. Enbridge intends to reverse the direction of flow on this system, which should ultimately increase market access for Canadian crude oil delivered on the Lakehead system. In December 2003, the Partnership announced the acquisition of crude oil pipeline and storage facilities in the U.S. Mid-Continent, which closed in the first quarter of 2004. This acquisition is expected to be accretive to cash distributions while, at the same time, increasing the diversity of sources of crude oil, thereby reducing the Partnership's dependence on western Canadian crude oil volumes.

The Partnership continues to grow its natural gas business with the acquisition of the North Texas gathering and processing system on December 31, 2003, adding to its presence in Texas. Effective October 2003, the Partnership made a decision to proceed with the construction of a pipeline to connect its East Texas system to the Carthage, Texas hub. Carthage access is important to shippers because it offers a number of connections to interstate natural gas pipelines. These projects are allowing the Partnership to achieve a larger scale and geographic profile from its East Texas system to its Anadarko system in the Texas panhandle, where it can pursue commercial and operating synergies that will make it the operator of choice in Texas.

The Partnership 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. The Partnership expects this trend to continue and believes it is well positioned to participate in these opportunities. The Partnership will seek out opportunities throughout the United States, particularly in the U.S. Gulf Coast area, where asset divestitures are anticipated in and around its existing natural gas gathering, processing and transportation businesses.

BUSINESS SEGMENTS

The Partnership conducts its business through four business segments: Liquids Transportation, Gathering and Processing, Natural Gas Transportation and Marketing.

- Liquids Transportation includes the operations of a common carrier pipeline and a feeder pipeline, which transport crude oil and other liquid hydrocarbons.
- Gathering and Processing consists of natural gas gathering pipelines, treating plants and processing plants. This segment also includes the transportation of natural gas liquids, crude oil and carbon dioxide by rail and road.
- Natural Gas Transportation includes the operations of natural gas transmission pipeline systems.
- The Marketing segment provides natural gas supply, transmission and sales services for customers.

Liquid Transportation Segment

Lakehead system

The Lakehead system in the United States and the Enbridge system in Canada, which is owned by Enbridge Pipelines, a wholly-owned subsidiary of Enbridge, together form the System. The System, which spans 3,100 miles, is the longest liquid petroleum pipeline system in the world and transports crude oil and other liquid petroleum products as a common carrier. The System is the primary transporter of crude oil from western Canada to the United States and the only pipeline that transports crude oil from western Canada to the province of Ontario in eastern Canada.

The System serves all the major refining centers in the Great Lakes and upper Midwest regions of the United States and the province of Ontario, 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 principally to refineries, either directly or through connecting pipelines of other companies, and serve as feedstocks for refineries and petrochemical plants.

The Lakehead system is a FERC regulated interstate common carrier pipeline system. The Lakehead system spans approximately 1,900 miles, and consists of approximately 3,300 miles of pipe with diameters ranging from 12 inches to 48 inches, 59 pump station locations with a total of approximately 752,000 installed horsepower and 60 crude oil storage tanks with an aggregate working capacity of approximately 14 million barrels. The System operates in a segregation, or batch mode. This operating mode allows the Lakehead system to transport up to 45 different types of liquid hydrocarbons 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 the Partnership's ability to serve its customers.

Customers. The Lakehead system operates under month-to-month transportation arrangements with its shippers. During 2003, 36 shippers tendered crude oil and liquid petroleum for delivery through the Lakehead system. These customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. The Lakehead system is well positioned as the primary transporter of western Canadian crude oil and will benefit from the growing production of crude oil from the Alberta oil sands. As with U.S. domestic conventional crude oil production, western Canada's conventional crude oil production is in decline. More than offsetting this decline is substantial growth in production from Canada's prolific oil sands resource from the WCSB.

The western Canadian oil sands are naturally occurring mixtures of sand, water, clay, and approximately 12% bitumen. According to the Alberta Energy and Utilities Board, using existing technology, knowledge and economics, the remaining recoverable bitumen reserves in the province of Alberta were estimated at the end of 2002 at approximately 174 billion barrels. This represents a recovery of approximately 10% of the initial volume in place (over 1.6 trillion barrels). The cumulative production of bitumen to the end of 2002 stood at approximately 3.8 billion barrels. According to industry sources, the economics of producing bitumen have improved substantially from the late 1970's when average production costs were nearly $23 per barrel (including extraction and upgrading costs). Bitumen production must be blended with lighter, less viscous materials to permit transportation via pipelines to refinery markets. Alternatively, bitumen can be upgraded into a synthetic crude oil to meet the demand from a greater number of refineries. Recent industry estimates of the cost of producing upgraded crude oil from the bitumen deposits are $7 to $10 per barrel.

Firms involved in the development of heavy crude oil from the Alberta oil sands have invested approximately $20.0 billion since 1995, with additional previously announced extraction or up-grader projects valued in excess of approximately $30.0 billion over the next ten years. This could provide up to 1.5 million bpd of incremental crude oil production from western Canada. Based upon Enbridge's survey of producers, refiners and governments conducted in early 2003, the supply of western Canadian crude oil and liquid petroleum is expected to be approximately 2.3 million bpd in 2004, 2.5 million bpd in 2005 and approximately 2.8 million bpd in 2010.

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 5% 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.

Supply from the WCSB, and hence future deliveries on the Lakehead system, is expected to grow over 2003 levels. The near-term growth in supply comes from the completion of the Syncrude and Suncor oil sands expansions and full year production from the AOSP and Cold Lake expansions. Syncrude and Suncor were the original oil sands producers in northern Alberta, and AOSP and Cold Lake expansions are separate producers and producing areas.

During the fourth quarter of 2003, Syncrude announced the completion of the second mining train at its Aurora Mining site, which increases the bitumen mining capacity of the Syncrude project in preparation for its Aurora Upgrader Expansion project. With the completion of this project, Syncrude's synthetic crude oil production capacity is expected to grow to approximately 350,000 bpd by 2005-2006 from approximately 230,000 bpd in 2002.

Suncor began upgrading bitumen from the first phase of its Firebag in-situ oil sands development near the end of 2003. Firebag phase one is expected to reach full production capacity of 35,000 bpd of bitumen production in mid-2005. When complete, the first phase of Firebag and expanded upgrader facilities are expected to bring Suncor's production capacity to 260,000 bpd in 2005, compared with 205,000 bpd in 2002.

The AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Western Oil Sands L.P. (20%) began commercial operation in June 2003. AOSP consists of oil sands mining and bitumen extraction operations in the Fort McMurray, Alberta region with transportation to the Fort Saskatchewan, Alberta area for upgrading to sweet and heavy synthetic crude oil products. Production from this operation averaged 122,500 bpd during initial operations in 2003. The project has a design capacity to process 155,000 of bpd bitumen.

Imperial Oil Limited recently completed certain phases of its Cold Lake expansion project. This project is expected to increase overall WCSB bitumen production by 30,000 bpd in 2004.

Based on the above noted oil sands activity and its most recent survey of crude oil shippers, the Partnership estimates that deliveries on the Lakehead system will average approximately 1.45 million bpd in 2004, an increase of approximately 100,000 bpd over 2003. The Partnership further believes that the outlook for increased crude oil production in western Canada continues to be positive and will yield additional volumes. In that event, the Partnership should expect increased earnings contributions from the Lakehead system. As an example, an incremental 100,000 bpd of deliveries on the Lakehead system to Chicago would increase operating income by approximately $10.0 million. The Partnership expects that increased capacity utilization on the Lakehead system should support a significant component of its future earnings growth. The timing of growth in the supply of western Canadian crude oil will depend upon the level of crude oil prices, oil drilling activity, the development of the oil sands resource, and access to compatible markets for Canadian oil sands production.

The Partnership's ability to increase deliveries and to expand its 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. 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, the System.

The Partnership forecasts that demand for WCSB production will continue to increase in PADD II, which is the U.S. Government's designation for the area that includes the Great Lakes and Midwest regions of the United States. 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 2.75 million bpd in 1984 to approximately 3.2 million bpd in 2002. Over that same period, production of crude oil within PADD II decreased from over 1.0 million bpd to approximately 450,000 bpd. The Partnership expects this gap between PADD II demand and production will continue to widen, contributing to increased demand for imports of crude oil to PADD II.

The closure of Petro-Canada's Oakville, Ontario refinery in late 2004, is expected to result in a decline in the volume of crude oil delivered by the Lakehead system to the province of Ontario and a corresponding increase in deliveries into the PADD II market. Following the announced refinery closure, Lakehead system deliveries into Ontario are expected to remain relatively constant.

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 undertaken at the request of 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, as discussed below, approximately 350,000 bpd of incremental capacity has been added to the System.

- Phase I of the Terrace expansion program was completed in 1999 and included construction of a new 36-inch diameter pipeline facility from Kerrobert, Saskatchewan to Clearbrook, Minnesota that added approximately 170,000 bpd of capacity to the System. The Partnership's share of the cost of Phase I was approximately $140.0 million.

- Phase II of the Terrace expansion program was completed in early 2002. Although Phase II did not involve construction on the Lakehead system, the approximate 40,000 bpd increase in capacity of the Enbridge system is expected to benefit the Partnership directly by accommodating additional deliveries on the Lakehead system from the Alberta oil sands.

- Phase III of the Terrace expansion program was substantially complete in early 2003 and is designed primarily to increase heavy crude oil transportation capacity on the Lakehead system between Clearbrook and Superior, Wisconsin by approximately 140,000 bpd. The Partnership's cost of Phase III was approximately $195.0 million.

- Following Phase III of the Terrace expansion program, CAPP has also requested, and the Partnership has undertaken, the expansion of pipeline capacity into the Chicago market. Construction of additional facilities is underway and expected to be in service in 2004. The Partnership's cost is expected to be approximately $80.0 million.

Competition. As pipelines are the lowest cost method for intermediate and long haul movement of crude oil over land, the most significant existing competitors for the transportation of western Canadian crude oil are other pipelines. In 2003, the Enbridge system transported approximately 67% of total western Canadian crude oil production; the remainder was either refined in the provinces of Alberta, British Columbia or Saskatchewan, Canada or transported through other pipelines. Of the pipelines transporting western Canadian crude oil out of Canada, the System provides approximately 77% of the total pipeline design capacity. The remaining 23% is shared among five other pipelines transporting crude oil to British Columbia, Washington, Montana and other states in the northwestern United States.

To address growing demand in the PADD IV and Puget Sound Area of PADD V, several expansions of these competing pipeline systems have been announced. Competing pipelines are owned by Terasen Inc. and transport crude oil from Alberta to British Columbia and Washington State through the Trans Mountain pipeline and from Alberta to the PADD IV region of the U.S. through the Express pipeline.

Terasen Inc. has stated that it plans to apply to the NEB for approval to increase the capacity of its Trans Mountain pipeline from approximately 188,100 bpd to 214,500 bpd. It is anticipated that this expansion will be in service during the third quarter of 2004.

Terasen Inc. has also announced plans to proceed with the expansion of the Express pipeline system from current capacity of 172,000 bpd to 280,000 bpd. Terasen Inc. expects this expansion to be in service by April 2005.

Another competitor, Inter Pipeline Fund, has announced a commercial agreement with four shippers to increase southbound capacity on its Bow River pipeline by 17,000 bpd. This system transports western Canadian crude to markets in Montana. Inter Pipeline Fund expects the new facilities will be in place by May 1, 2004.

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

In the United States, the Lakehead system encounters competition from other liquid petroleum pipelines and other modes of transportation delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Minnesota; Superior, Wisconsin; Chicago, Illinois; Detroit, Michigan; Toledo, Ohio; and the Patoka/Wood River area in southern Illinois.

The following table sets forth Lakehead system average deliveries per day and barrel miles for each of the five-year periods ended December 31, 2003.

	Deliveries				
	2003	2002	2001	2000	1999
	(thousands of bpd)				
United States					
Light crude oil	258	266	292	321	299
Medium and heavy crude oil	741	665	663	630	575
NGL	4	6	5	25	24
Total United States	1,003	937	960	976	898
Ontario					
Light crude oil	174	171	174	174	282
Medium and heavy crude oil	68	83	77	85	87
NGL	109	111	104	103	102
Total Ontario	351	365	355	362	471
Total Deliveries	1,354	1,302	1,315	1,338	1,369
Barrel miles (billions per year)	345	341	333	341	350

North Dakota system

The North Dakota system is a crude oil gathering and transportation system servicing the Williston Basin in North Dakota and Montana. The North Dakota system's crude oil gathering pipelines collect crude oil from points near producing wells in approximately 36 oil fields in North Dakota and Montana and receive Canadian crude oil via an interconnect with an Enbridge gathering system in the province of Saskatchewan, Canada. Most deliveries are made at Clearbrook to the Lakehead system and to a third-party pipeline system. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long, with an aggregate working capacity of approximately 84,000 barrels per day. The North Dakota system also has 16 pump stations and 12 terminaling facilities with an aggregate working storage capacity of approximately 700,000 barrels.

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

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

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

Gathering and Processing Segment

The Partnership owns and operates natural gas gathering, treating and processing systems. These systems 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.

Most of the natural gas gathering, treating and processing assets are located in Texas, with additional facilities in Oklahoma, Mississippi, Louisiana, Kansas and Alabama. The major facilities are listed in the following table:

System	Miles of Pipeline	Active Treating Plants	Active Processing Plants	2003 Volume (MMBtu/d)
East Texas	2,000	2	2	446,000
Northeast Texas	1,200	4	2	133,000
North Texas	2,000	–	5	198,000
Anadarko	730	1	2	256,000
South Texas	175	1	0	38,000
Harmony	150	1	1	9,000
		9	12	

In total, the Partnership has over 6,200 miles of gathering pipelines, 9 active treating plants and 12 active processing plants. The active treating and processing capacities are currently over 700 MMcf/d and 600 MMcf/d respectively.

The Northeast Texas system is capable of handling sour gas, which has a high hydrogen sulfide and/or carbon dioxide and water content and which 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.

The Partnership acquired the North Texas system on December 31, 2003, for approximately $249.7 million, which also includes the buyout of a capital lease of $1.9 million and transaction costs of $1.8 million. Three of the processing plants receive natural gas primarily from a conglomerate formation in the Fort Worth Basin. A fourth plant receives gas from both the conglomerate and Barnett Shale formations in the Fort Worth Basin. The fifth active processing plant processes gas on a third party pipeline under a combination of a fee-for-service and a products-sharing arrangement with that third party pipeline. The system also includes two pipeline systems that gather lean gas in the Barnett Shale region for a fixed gathering fee. The larger of these two pipelines commenced operation in 2001 and has been growing rapidly with the expansion of the Barnett Shale production. Volume data for 2003, noted in the table above, is derived from the records of the prior owner.

Customers. Customers of the Partnership's 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 the Partnership's systems consist of small, medium and large independent operators and large integrated energy companies. The Partnership sells NGLs resulting from its processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

Supply and Demand. Supply for the Partnership's gathering, treating and processing services primarily depends upon the rate of depletion of natural gas reserves and the drilling rate of new wells. Treating services also are affected by the level of impurities in the natural gas gathered. Demand for these services depends upon overall economic conditions and the prices of natural gas and NGLs. Three of the Partnership's 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 have 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 2003.

A substantial portion of natural gas on the North Texas system is produced in the Barnett Shale within the Fort Worth Basin Comglomerate. The Fort Worth Basin Conglomerate is a mature zone that is experiencing slow decline. In contrast, the Barnett Shale 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 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 750 MMcf/d since 2000 with the drilling of over 2,000 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 County, Texas.

The Partnership intends to expand its 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 the treating and processing businesses.

Competition. Competitors of the Partnership's 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 the Partnership. 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 the Partnership's Northeast 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.

Trucking Operations

Also included in the Partnership's Gathering and Processing segment are its trucking operations. 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. These services are provided using 105 trucks and trailers and 48 rail cars, product treating and handling equipment and over 400,000 gallons of NGL storage facilities. In addition, a CO_2 plant with 250 tons per day of capacity, takes excess CO_2 from hydrogen producers and sells it to a variety of customers.

Customers. Most of the customers of the crude oil and NGL trucking operations are wholesale customers, such as refineries and propane distributors. The trucking operations also market products to wholesale customers such as refineries and petrochemical plants.

Supply and Demand. The areas served by the Partnership's trucking operations are geographically diverse, and the forces that affect the supply of the products transported vary by region. The supply of these products is affected by crude oil and natural gas prices and production levels. 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. The 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 the trucking operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Natural Gas Transportation Segment

Included in this segment are the following major systems that were acquired in connection with the Midcoast system acquisition in October 2002:

- the KPC Pipeline, MidLa Pipeline, AlaTenn Pipeline, and UTOS Pipeline systems, which are FERC regulated natural gas interstate transmission pipelines; and

• the Bamagas Pipeline, Mid-Louisiana Gas Transmission Pipeline and Magnolia Pipeline systems, which are natural gas intrastate transmission pipelines.

Each of these pipeline systems typically consists of a natural gas transmission pipeline as well as various interconnects to other pipelines that serve wholesale customers.

Customers. The Partnership's natural gas transportation 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. As the Partnership's natural gas transportation pipelines generally serve different geographical areas, supply and demand vary in each market.

The Partnership believes that demand for natural gas in the areas served by its natural gas transportation 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, 2003 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, 2003
UTOS System	1,200	0%
MidLa System	200	88%
AlaTenn System	200	49%
KPC System	160	94%
Bamagas System	450	61%

The UTOS system is a FERC-regulated offshore pipeline system with a capacity of 1.2 billion cubic feet of natural gas per day that transmits natural gas from offshore platforms to other pipelines onshore for further delivery. The UTOS system's average daily throughput during 2003 was 209,000 MMBtu/d. The FERC has approved the Partnership's 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. This system is contiguous with the AlaTenn system and a third party pipeline, allowing for operational flexibility as natural gas could flow between Bamagas and either of the other two systems. The Partnership markets 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. The AlaTenn system had contracts representing 21% of its capacity that terminated in 2003. Expiration of the AlaTenn contracts did not have a material impact on the business segment. As of December 31, 2003, approximately 62% 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.

The Partnership's long-term financial condition depends on the continued availability of natural gas for transportation to the markets served by its 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 served by the Partnership was to render the delivered cost of natural gas uneconomical. The Partnership may be unable to find additional customers to replace the lost demand or transportation fees.

Competition. Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of the Partnership's natural gas transportation 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 the Partnership 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.

Marketing Segment

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

Natural gas purchased and sold by the 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.

The 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

The Partnership's financial performance depends to a large extent on the volume of products transported on its pipeline systems. Decreases in the volume of products transported by the Partnership's systems, whether caused by supply and demand factors in the markets these systems serve, or otherwise, can directly and adversely affect the Partnership's revenues and results of operations. See "Business Segments—Liquids Transportation Segment—Lakehead system—Supply and Demand";—"Business Segments—Gathering and Processing Segment—Supply and Demand"; and "Business Segments—Natural Gas Transportation Segment—Supply and Demand".

Regulation

The tariff rates charged by several of the Partnership's systems are regulated by the FERC or various state regulatory agencies. If the Partnership's tariffs are reduced by one of these regulatory agencies on its own initiative or as a result of challenges by third parties, the profitability of the Partnership's pipeline businesses may suffer. If the Partnership is permitted to raise its tariffs for a particular pipeline, there may be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect. Furthermore, competition from other pipeline systems may prevent the Partnership from raising its tariff rates even if regulatory agencies permit the Partnership to do so. The regulatory agencies that regulate the Partnership's 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 services by the Partnership. Several states, including Oklahoma and Texas, are taking a more active role in the rate and service regulation of intrastate natural gas systems. Increased state regulation could adversely impact the Partnership's natural gas systems.

Competition with Enbridge

Enbridge has agreed with the Partnership that, so long as an affiliate of Enbridge is the general partner of the Partnership, Enbridge and its subsidiaries may not engage in or acquire any business that is in direct material competition with the businesses of the Partnership, 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 the Partnership's initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which the Partnership provided transportation at the time of the Partnership's 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 the Partnership and the Partnership fails to approve, after submission to a vote of unitholders, the making of the acquisition.

As the Partnership was not engaged in any aspect of the natural gas business at the time of its initial public offering, Enbridge and its subsidiaries are not restricted from competing with the Partnership in any aspects 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 the business of the Partnership.

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 the Partnership to supply crude oil to the Ontario, Canada market. This competition from Enbridge has reduced the Partnership's deliveries of crude oil to Ontario.

Market Risk

As part of its natural gas marketing activities, the Partnership purchases natural gas at prevailing market prices. Following the purchase of natural gas, the Partnership generally resells 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 the Partnership's 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 its customers to make timely payment, customer default, and concentration of receivables with third parties in the energy sector.

Environmental and Safety Regulations

The Partnership's 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 the Partnership 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. The Partnership 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, the Partnership will not be able to quantify the impact, if any, of the Kyoto Protocol on its operations. The Partnership is 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 the control of the Partnership. For example, the East Texas, Northeast 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 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 the Partnership's strategic plan. Acquisitions may present various risks and challenges, including the risks of incorrect assumptions in the acquisition models, effective integration of the acquired operations and diversion of management's attention from existing operations. In addition, the Partnership may be unable to identify acquisition targets and consummate acquisitions in the future or be unable to raise, on terms acceptable to it, 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 the Partnership's 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.

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 Lakehead system 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.

Conflicts of Interest

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

The Partnership's partnership agreement limits the fiduciary duties of the general partner of the Partnership to the Partnership's unitholders. These restrictions allow the general partner of the Partnership to resolve conflicts of interest by considering the interests of all the parties to the conflict, including Enbridge Management's interests, the interests of the Partnership and the General Partner. Additionally, these limitations reduce the rights of the Partnership's unitholders under the Partnership's partnership agreement to sue the general partner of the Partnership 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 the Partnership could reduce the cash distributions on the common units and the value of the i-units that the Partnership will distribute quarterly to Enbridge Management. Currently, state-level income taxation of the Partnership 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 would cause a reduction in the value of the partnership units.

TITLE TO PROPERTIES

The Partnership currently conducts business and owns properties located in 20 states: Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, North Carolina, North Dakota, Oklahoma, Texas, Tennessee and Wisconsin. In general, the Partnership's 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 these systems are located on land that is owned by the Partnership, except for five pumping stations that are situated on land owned by others and used by the Partnership under easements or permits.

Substantially all of the Lakehead system assets are subject to a first mortgage securing indebtedness of the Lakehead Partnership, a principal operating subsidiary of the Partnership.

In connection with the acquisition of the Midcoast system, certain filings with respect to title records were not made prior to the closing of the transaction. The Partnership or its subsidiaries have now made these filings. Although title to these properties is subject to encumbrances in some cases, the Partnership believes that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of the Partnership's business.

REGULATION

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The Lakehead and North Dakota systems are interstate common carrier liquids pipelines subject to regulation by the FERC under the ICA. As interstate common carriers, 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 the Partnership to maintain tariffs on file with the FERC that set forth the rates it charges for providing transportation services on its 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 the Partnership charges for service on its 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 that it was previously contractually barred from challenging the rates or that the economic circumstances or the nature of service underlying the rate had substantially changed or 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 system is 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 alternatives may be used in certain specified circumstances.

The Partnership believes that the rates charged for transportation services on its interstate common carrier liquids pipelines are just and reasonable under the ICA. However, because the rates that the Partnership charges are subject to review upon an appropriately supported complaint, the Partnership cannot predict what rates it will be allowed to charge in the future for service on its 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 the Partnership's tariffs will be determined based on competitive factors in addition to regulatory considerations.

Allowance for Income Taxes in Rates

In a 1995 decision involving the Partnership's 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 have appealed the FERC's orders to the U.S. Court of Appeals for the District of Columbia Circuit. Arguments in the appeals were completed in the fall of 2003 and the court's decision is pending. The effect of the FERC's policy stated in the Lakehead proceeding (and the results of the ongoing SFPP litigation regarding that policy) on the Partnership is uncertain. Parties may challenge rates on the Partnership's common carrier interstate liquids pipelines on the basis that its rates are not just and reasonable because the level of income tax allowance in its rates exceeds that permitted under the Lakehead and/or SFPP decisions. It is not possible to predict the likelihood that parties will assert such challenges or that such challenges would succeed. If the Court of Appeals were to follow the Lakehead decision, and challenges were to be raised and succeeded, application of the Lakehead/SFPP and related rulings would reduce permissible income tax allowance in any cost-of-service based rate, to the extent income tax is attributed to partnership interests held by individuals and other non-corporate entities.

Regulation by the FERC of Interstate Natural Gas Pipelines

The Partnership's 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 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 the UTOS system under the NGA and the NGPA, the FERC also has jurisdiction over the UTOS system and the Partnership's 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 the Partnership's operations, although the Partnership does not believe that these regulations will affect it any differently than any other interstate pipelines with which its competes.

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 large interstate pipeline companies.

Intrastate Pipeline Regulation

The Partnership's 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 the Partnership's 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. The Partnership owns certain natural gas pipelines that it believes 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 unregulated affiliates. 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. The Partnership's 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. The Partnership's 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. The Partnership cannot predict what effect, if any, such changes might have on its 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 the Partnership sells natural gas currently is not subject to federal or state regulation except for certain systems in Texas. The Partnership's 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. The Partnership cannot predict the ultimate impact of these regulatory changes to its 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. The Partnership does not believe that it will be affected by any such FERC action in a manner that is materially different than other natural gas marketers with whom it competes.

The Partnership's 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, the Partnership does not believe that these regulations affect it 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, 2003 (including the tariff surcharges related to 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	$0.171
To Superior, Wisconsin	$0.332
To Chicago, Illinois area	$0.676
To Marysville, Michigan area	$0.807
To Buffalo, New York area	$0.826
Chicago to the international border near Marysville	$0.301

The rates at December 31, 2003 for medium and heavy crude oils are higher, and those for NGLs are lower than the rates set forth in the table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. The Partnership periodically adjusts its 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, the Partnership 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, the Partnership's share of the surcharge was increased to $0.026 per barrel. Subject to any adjustments permitted under the tariff agreement, this surcharge will be effective until April 1, 2004, when the surcharge to the Partnership will change to $0.007 per barrel. This new tariff is expected to be in effect for the next six years, after which time it will return to $0.013 per barrel for the Partnership through 2013, the term of the agreement.

Natural Gas Transportation 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. The rates charged for transmission of natural gas on pipelines not regulated by the FERC, or a state agency, are established by competitive forces. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Environmental and Safety Regulation

General

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

Pipeline Safety and Transportation Regulation

The Partnership's transmission and non-rural gathering pipelines are subject to regulation by the U.S. Department Of Transportation, 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" (Act) was signed into legislation 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. The Partnership anticipates new rules regulating pipeline security, contractor drug testing, inspection, public awareness programs and annual information reporting. 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, the Partnership is not certain of the effect or costs that the new requirements may have on its operations.

Various states in which the Partnership operates have authority to issue additional regulations affecting intrastate or gathering pipeline design, safety and operational requirements.

The Partnership's 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 materials and other materials.

The Partnership believes that its pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, the Partnership has 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 its current pipeline control system or other safety equipment.

Pressure Restrictions on the Lakehead system

Following a leak that occurred on the Lakehead system in July 2002, the federal Office of Pipeline Safety imposed pressure restrictions on the entire line that was affected. The Partnership 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 the 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 repairs in 2005, and after evaluation of the interim performance of the line and the Partnership's progress in implementing its risk management plan. Based on the Partnership's forecast of deliveries for 2004, the remaining ten percent pressure restriction is not expected to negatively impact its earnings.

Environmental Regulation

General. The Partnership's 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 the overall cost of doing business, including its capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect its maintenance capital expenditures and net income, the Partnership believes that they do not affect its competitive position since the operations of its competitors are 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. The Partnership believes that its operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with the Partnership's operations, such as leaks or spills of crude oil, liquids or natural gas or other substances from its pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject the Partnership 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 the Partnership is entitled in certain circumstances to indemnification from third parties for environmental liabilities relating to assets it acquired from those parties, these contractual indemnification rights are limited and, accordingly, the Partnership may be required to bear substantial environmental expenses. However, the Partnership believes that through its due diligence process substantial issues are identified and managed.

Air and Water Emissions. The Partnership's operations are subject to the federal Clean Air Act and the federal Clean Water Act and comparable state and local statutes. The Partnership anticipates, therefore, that it will incur certain capital expenses in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities. The Partnership believes compliance with these CAA and CWA requirements will not have a material adverse effect on its financial condition.

An operating permit excursion occurred at the Bryans' Mill Treating Plant in 2003 where a significant amount (approximately 7000 tons) of sulphur-dioxide (SO2) was released above permit limits and was self-reported to the applicable state agency. A plant catalyst bed was found to be deficient and the problem has been corrected. Administrative reporting systems and operations procedures have been augmented for the prevention of future occurrences. An accrual has been made 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, the Partnership could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from its 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 the Partnership's 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 the Partnership's pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For the Partnership's non-transportation facilities, such as storage tanks, the OPA regulations are promulgated by the EPA. The Partnership believes it is in material compliance with these laws and promulgating 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. The Partnership may generate some wastes that fall within the definition of a "hazardous substance." The Partnership may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required cleaning up and restoring 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. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or similar state laws.

Employee Health and Safety. The workplaces associated with the Partnership's operations are subject to the requirements of the federal OSHA and comparable state statutes that regulate worker health and safety. The Partnership has an ongoing safety-training program for its employees and believes that its operations are in compliance with applicable occupational health and safety requirements, including general industry standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

Site Remediation. The Partnership owns and operates 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. The Partnership or its predecessors have operated certain facilities, including the Lakehead system since 1950. Many of the other facilities of the Partnership were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under the Partnership's 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 the Partnership's properties may be subject to CERCLA, RCRA and analogous state laws as described above. Under these laws, the Partnership 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 the Partnership, could also be liable for such costs to the extent that the Partnership is unable to fulfill its obligations. The Partnership has conducted site investigations at some of its facilities to assess historical environmental issues, and it is 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 the Partnership's 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 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 under the contribution agreement between the General Partner and the Partnership. In addition, the Partnership 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 the Partnership believes 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 the Partnership may be liable or bears some responsibility for such obligations.

EMPLOYEES

Neither the Partnership, nor Enbridge Management, has any employees. The General Partner has delegated to Enbridge Management, pursuant to the Delegation of Control Agreement, substantially all of the responsibility for the day-to-day management and operation of the Partnership. The General Partner, however, retains certain functions and approval rights over the operations of the Partnership. 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. The Partnership is ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

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

CAPITAL EXPENDITURES

In 2003, the Partnership made capital expenditures of $129.3 million, of which $65.9 million was for pipeline system enhancements, $28.8 million for core maintenance activities and $34.6 million for the Terrace expansion program. 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, the Partnership is not a taxable entity. Federal and state income taxes on Partnership taxable income are borne by the individual partners through the allocation of Partnership taxable income. Such taxable income may vary substantially from net income reported in the statement of income.

OTHER MATTERS

In October 2002, the Partnership acquired the Midcoast, Northeast Texas, and South Texas systems from the General Partner (the "Acquisition"). A committee of independent members of the Board of Directors of the General Partner negotiated the purchase price and terms of the Acquisition on behalf of the Partnership's public unitholders and recommended that the Board approve the Acquisition. The independent committee retained its own expert financial and legal advisors to assist in this process and the financial advisor rendered a fairness opinion in connection with the Acquisition.

In November 2002, the staff of the SEC advised the Partnership, Enbridge Management, the General Partner and Enbridge (the "Enbridge Group"), that it had commenced an informal inquiry into the Acquisition and the initial public offering by Enbridge Management. The SEC staff has advised the Enbridge Group that its principal focus includes the financial forecast made in connection with the Acquisition and the price paid for the assets. The SEC staff has not asserted that the Partnership or the other Enbridge entities has acted improperly or illegally, and it has not indicated an intention to seek a formal order of investigation. The Enbridge Group is cooperating fully with the SEC staff.

Based on an internal review of the forecast and terms of the Acquisition, the Enbridge Group continues to believe that the financial forecast had a reasonable basis and the price paid for the assets was fair to the Partnership. The Partnership believes that the informal investigation will not have a material adverse effect on the financial condition of the Partnership.

Item 3. Legal Proceedings

The Partnership is a party in a limited number of legal proceedings arising in the ordinary course of business. The Partnership believes that the outcome of these matters 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 2003.

PART II

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

The Partnership's Class A Common Units are listed and traded on the New York Stock Exchange, 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 2003 and 2002 are summarized as follows:

	First	Second	Third	Fourth
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
2002 Quarters				
High	$46.25	$46.75	$46.25	$44.00
Low	$41.00	$43.15	$35.68	$37.80
Cash distributions paid	$ 0.90	$ 0.90	$ 0.90	$ 0.90

On March 1, 2004, the last reported sales price of the Class A Common Units on the NYSE was $50.20. At March 1, 2004, there were approximately 70,000 Class A Common Unitholders, of which there were approximately 2,200 registered Class A Common Unitholders of record. There is no established public trading market for the Partnership's Class B Common Units, all of which are held by the General Partner, or the Partnership's 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, summary historical financial data for the Partnership. The table is derived from the consolidated financial statements of the Partnership and notes thereto, and should be read in conjunction with those audited financial statements. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year ended December 31,				
	2003	2002	2001	2000	1999
	(dollars in millions, except per unit amounts)				
Income Statement Data:					
Operating revenue	$3,172.3	$1,185.5	$ 342.3	$ 307.0	$ 314.0
Operating expenses	2,978.0	1,047.5	244.5	189.1	182.3
Operating income	194.3	138.0	97.8	117.9	131.7
Interest expense	(85.0)	(59.2)	(59.3)	(60.4)	(54.1)
Other income (expense)	2.4	(0.2)	0.9	3.4	2.0
Minority interest	—	(0.5)	(0.5)	(0.7)	(0.9)
Net income	$ 111.7	$ 78.1	$ 38.9	$ 60.2	$ 78.7
Net income per unit (1)	$ 1.93	$ 1.76	$ 0.98	$ 1.78	$ 2.48
Cash distributions paid per unit	$ 3.70	$ 3.60	$ 3.50	$ 3.50	$ 3.485
Financial Position Data (at year end):					
Property, plant and equipment, net	$2,465.6	$2,253.3	$1,486.6	$1,281.9	$1,321.3
Total assets	$3,231.8	$2,834.9	$1,649.2	$1,376.7	$1,413.7
Long-term debt	$1,155.8	$1,011.4	$ 715.4	$ 799.3	$ 784.5
Loans from General Partner and affiliates	$ 133.1	$ 444.1	$ 176.2	—	—
Partners' capital:					
Class A common units	$ 914.9	$ 604.8	$ 577.0	$ 488.6	$ 533.1
Class B common units	64.2	48.7	48.8	42.1	47.4
i-units	370.7	335.6	—	—	—
General Partner	27.5	18.8	6.5	5.2	5.6
Accumulated other comprehensive (loss) income	(64.0)	(16.3)	11.9	—	—
	$1,313.3	$ 991.6	$ 644.2	$ 535.9	$ 586.1
Cash Flow Data:					
Cash flows from operating activities	$ 132.1	$ 200.6	$ 125.3	$ 118.9	$ 101.6
Cash flows used in investing activities	(431.0)	(557.2)	(302.1)	(22.3)	(91.1)
Cash flows from (used in) financing activities	303.0	376.7	179.8	(99.4)	(17.5)
Acquisitions and capital expenditures included in investing activities, net of acquired working capital	(423.5)	(563.9)	(300.0)	(21.7)	(82.9)

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating net income per unit: 2003, $19.6 million; 2002, $13.1 million; 2001, $9.1 million; 2000, $8.8 million and 1999, $9.1 million.

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

The following discussion and analysis of the Partnership's financial condition and results of operations are based on its Consolidated Financial Statements, which were 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 accompanying notes of the Partnership listed in the Index to Consolidated Financial Statements on page F-1 of this report.

Business Overview

The Partnership provides services to its customers and creates value for its unitholders primarily through the following activities:

- Interstate transportation of crude oil and liquid petroleum;
- Gathering, treating, processing and transmission of raw natural gas;
- Interstate and intrastate transmission of natural gas; and
- Providing supply, transmission and sales service, including purchasing and selling natural gas.

The Partnership primarily provides fee-based services to customers to minimize commodity price risks. However, in the Partnership's natural gas businesses, a portion of its earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure, the Partnership enters into hedge transactions.

The Partnership conducts its business through four business segments: Liquids Transportation, Gathering and Processing, Natural Gas Transportation and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of the Partnership's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

Liquids Transportation

Liquids Transportation includes the operations of the Lakehead and North Dakota 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.

The 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 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 construction projects in progress, this stable source of supply is expected to increase significantly over the next ten years.

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

Gathering and Processing

Gathering and Processing includes the East Texas system, acquired on November 30, 2001, the Northeast Texas system, the South Texas system and certain other assets of the Midcoast system, all of which were acquired from the General Partner in October 2002, and the North Texas system, acquired on December 31, 2003. Collectively, these systems include natural gas gathering and transmission pipelines, nine active natural gas treating plants and twelve active natural gas processing plants. The

Midcoast system assets acquired also include trucks, trailers and rail cars used for transporting NGLs, crude oil and carbon dioxide. The Gathering and Processing assets are largely located in the Mid-Continent and Gulf Coast regions of the United States.

The Partnership receives revenues for its gathering and processing services under the following types of arrangements:

Fee-Based Arrangements: Under a fee-based contract, the Partnership receives 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. The Partnership prefers fee-based contracts because they produce relatively stable cash flows.

Other Arrangements: While the Partnership prefers fee-based contracts, it also utilizes other types of arrangements in its natural gas gathering and processing business, including:

- Percentage-of-Index Contracts—Under these contracts, the Partnership purchases raw natural gas at a negotiated discount to an agreed upon index. 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 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, which it sells at market prices. In instances when the Partnership purchases raw gas at the wellhead, it also sells for its own account at market prices the residue gas resulting from processing. In those instances where 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 arrangements expose the Partnership to commodity price risk, which is mitigated by offsetting physical purchases and sales and the use of financial derivative instruments. In addition, the Partnership occasionally takes title to natural gas and NGLs for other reasons, such as to sell these products to customers. The Partnership 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.

Natural Gas Transportation

Natural Gas Transportation consists of four FERC regulated natural gas transmission pipeline systems and 35 intrastate natural gas transmission and wholesale customer pipeline systems located in the Mid-Continent and Gulf Coast regions of the United States. These pipeline systems form part of the Midcoast system assets that were acquired from the General Partner in October 2002.

The Partnership's FERC-regulated interstate natural gas transmission pipeline systems generally derive their revenue from capacity reservation fees charged for transmission of natural gas, while its intrastate pipelines generally derive their revenue from the bundled sales of natural gas and from transmission services. Customers of the Partnership's 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. In some cases, the Partnership's Marketing operation uses the capacity on these pipeline systems to sell natural gas it owns to its customers, such as local distribution companies or industrial facilities.

Marketing

The Partnership's Marketing segment provides supply, transmission and sales service for producers and wholesale customers on its 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 customers.

In general, 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, the Partnership will enter into long-term fixed price purchase or sales contracts with its customers and generally will enter into offsetting hedged positions under the same or similar terms.

Critical Accounting Policies and Estimates

The Partnership's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires 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 these 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 effects on the Partnership's 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. The Partnership believes the critical accounting policies and estimates discussed in the following paragraphs affect the more significant judgments and estimates used in the preparation of its consolidated financial statements.

Revenue Recognition

In general, the Partnership recognizes revenue when delivery has occurred or services have been rendered, pricing is determinable and collectibility is reasonably assured. For its natural gas businesses, the Partnership records an estimate each month for its 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 the Partnership's operating revenues and cost of natural gas for each of the years ended December 31, 2003, 2002 and 2001. These estimates are based on the best available volume and price data. The Partnership believes 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 the Partnership's processes.

Property, Plant and Equipment

Property, plant and equipment is recorded at its original cost and is depreciated based on the lesser of the estimated useful lives of the assets or the estimated remaining life of crude oil or natural gas production in the basins served by the pipelines. Determining the useful life requires various assumptions to be made, including the supply of and demand for hydrocarbons in the markets served by 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 the financial statements. Additionally, if it is determined that an asset's undepreciated cost may not be recoverable due to economic obsolescence, the business climate, legal and other factors, the asset would be reviewed for impairment and any necessary reduction in its value would be recorded as a charge against earnings. If there are changes to any of the estimates and assumptions, actual results may differ. If an average remaining service life of 20 years had been used (compared to the average remaining service life of approximately 25 years in the 2003 results), depreciation expense would be $119.3 million or $23.1 million higher and net income per unit would have been $1.45 or $0.48 lower. If an average remaining service life of 30 years had been used, depreciation expense would be $79.5 million or $16.7 million lower and net income per unit would have been $2.28 or $0.35 higher.

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 indicate 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. To estimate the fair value of the reporting units, management makes 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 Partnership's most recent five-year plan to manage the business. Preparation of forecast information for use in the five-year plan involves significant judgments. Based on the results of the impairment analysis, the fair value of the total equity of each reporting unit is deemed to exceed the respective carrying value.

Actual results can, and often do, differ from the projections and assumptions made. These changes can have a negative impact on the estimates of impairment, which would result in charges to income. In addition, further changes in the economic and business environment can impact the Partnership's 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 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 future cash flows of the Partnership.

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. If there are changes to any of the 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 Partnership unitholders, the General Partner uses 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 and in use by the Partnership can be divided into two categories: 1) cashflow hedges, or 2) fair value hedges. Cashflow hedges are entered into to hedge the variability in cashflow(s) 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 have an impact on net income results 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 the Partnership's 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 the Partnership's control.

At inception and on an ongoing basis, the Partnership also assesses whether the derivatives that are used in its hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedged item. To the extent the 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. 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 would be reported directly in the income statement.

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. The Partnership uses 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, 2003, 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 the Partnership's non-cash earnings to fluctuate based upon changes in underlying indexes, primarily commodity prices. Fair value for 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, 2003, the Partnership recognized losses of $0.3 million in the Consolidated Statement of Income, as part of the Cost of Natural Gas balance of the Marketing segment. The fair value of the basis swaps at December 31, 2003, is a payable of $0.3 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, the Partnership had a limited number of open positions that extend beyond December 31, 2004.

Commitments, Contingencies and Environmental Liabilities

The Partnership accrues reserves for contingent liabilities, including environmental remediation and clean-up costs, when its 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 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 circumstances and the revisions are reflected in the Partnership's income in the period in which they are reasonably determinable. The Partnership evaluates recoveries from insurance coverage separately from its liability and, when recovery is reasonably assured, it records and reports an asset separately from the associated liability in its 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 current or past operations, could result in substantial cost and future liabilities.

The Partnership recognizes liabilities for other contingencies when it has 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. The Partnership's potential exposure to adverse outcomes is evaluated by both internal and external counsel. When a range of probable loss can be estimated, the Partnership accrues the most likely amount, or at least the minimum of the range of probable loss. To the extent that actual outcomes differ from estimates or additional facts and circumstances cause the Partnership to review its 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 recorded on the Partnership 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 the oil shortage balance or revision of oil measurement loss estimates. The balances are included in the Accounts Payable and other in the Consolidated Statement of Financial Position.

Operational Balancing Agreements and Natural Gas Imbalances

Payables and receivables associated with natural gas pipeline operational balancing agreements and natural gas imbalances 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 the Partnership's consolidated revenues, expenses, operating income, net income and net income per unit.

	Year ended December 31,		
	2003	2002	2001
	(dollars in millions, except per unit amounts)		
Operating Revenues	$ 3,172.3	$ 1,185.5	$ 342.3
Expenses	(2,978.0)	(1,047.5)	(244.5)
Operating income	$ 194.3	$ 138.0	$ 97.8
Net income	$ 111.7	$ 78.1	$ 38.9
Net income per unit	$ 1.93	$ 1.76	$ 0.98

The increases in overall operating revenue, expenses, operating income and net income in 2003 compared with 2002 are attributable to the full year contribution from the Midcoast system, which was acquired by the Partnership in October 2002 and improved performance on the Lakehead and East Texas systems. Increases in operating revenue, expenses, operating income and net income in 2002 compared with 2001 resulted from the full-year contribution of the East Texas system acquired in December 2001 and the partial year contribution from the Midcoast system.

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

	Year ended December 31,		
	2003	2002	2001
	(dollars in millions)		
Operating Income			
Liquids Transportation	$124.5	$112.1	$ 97.7
Gathering and Processing	48.4	20.2	0.1
Natural Gas Transportation	15.2	3.9	—
Marketing	9.4	1.8	—
Corporate, operating and administrative*	(3.2)	—	—
Total Operating Income	$194.3	$138.0	$ 97.8
Corporate*	(82.6)	(59.9)	(58.9)
Net Income	$111.7	$ 78.1	$ 38.9

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

Liquids Transportation

The results of operations for the Liquids Transportation segment include the Lakehead system and the North Dakota system, since its acquisition by the Partnership in May 2001.

	Year Ended December 31,		
	2003	2002	2001
	(dollars in millions)		
Operating Revenues	$ 344.2	$ 334.3	$ 313.3
Operating and administrative	$(104.1)	$(104.7)	$(102.7)
Power	(56.1)	(52.7)	(49.9)
Depreciation and amortization	(59.5)	(64.8)	(63.0)
Expenses	$(219.7)	$(222.2)	$(215.6)
Operating income	$ 124.5	$ 112.1	$ 97.7

The following table sets forth the Lakehead system's average deliveries per day, barrel miles, and average haul:

	Year ended December 31,		
	2003	2002	2001
		(average bpd)	
United States	1,003	937	960
Province of Ontario	351	365	355
Total deliveries (thousands)	1,354	1,302	1,315
Barrel miles (billions)	345	341	333

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

Operating income was higher in 2003 compared with 2002 due to higher revenue and lower operating expenses, including depreciation. Operating revenue was $9.9 million higher in 2003 compared with 2002 due to higher deliveries on the 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. 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. Due to startup challenges at the newest upgrader, known as the Athabasca Oil Sands Project ("AOSP"), 2003 crude oil production lagged behind expectations. This delayed the expected increase in western Canadian oil production during the year, and as a result, impacted the level of deliveries on the Lakehead system.

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 Producers Price Index for Finished Goods ("PPI") less one percent with an index of PPI 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 PPI adjustment was negative.

Power costs increased by $3.4 million in 2003 to $56.1 million from $52.7 million in 2002 primarily due to the increase in deliveries on the Lakehead and North Dakota systems.

Operating and administrative expenses decreased by $0.6 million to $104.1 million in 2003 from $104.7 million in 2002. The Partnership 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 higher 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.

Year ended December 31, 2002 compared with year ended December 31, 2001

Operating income for 2002 was $112.1 million compared with $97.7 million for 2001. Operating income was higher in 2002 compared with 2001 primarily due to higher revenues, partially offset by higher operating expenses. Operating income for 2002 includes the full year results of the North Dakota acquisition, whereas 2001 includes the results from the date of acquisition of May 18, 2001.

Operating revenue was higher in 2002 compared with 2001 due to increased tariffs and a full year contribution from the North Dakota system, partially offset by lower deliveries on the Lakehead system. Tariffs were higher due to positive adjustments calculated under FERC regulations and agreements with customers. As well, the amount of heavy oil transported on the Lakehead system, which attracts a higher tariff, was higher in 2002 compared with 2001. Volumes delivered on the Lakehead system declined over the period as western Canadian crude oil was delivered to other markets on competing pipeline systems.

Operating and administrative expenses were higher in 2002 by $2.0 million compared with 2001. This increase was due to higher workforce costs, as well as expenses related to a Lakehead system pipeline leak in July 2002, partially offset by lower oil measurement losses and the non-recurring charge in 2001 related to the relocation of the Partnership's head office to Houston.

Depreciation expense was higher in 2002 by $1.8 million compared with 2001, due to plant additions from the prior year and a full year impact of the North Dakota system.

Gathering and Processing

The results of operations for the Gathering and Processing segment include the East Texas system since its acquisition date on November 30, 2001, and the remaining systems purchased as part of the Midcoast system since their acquisition on October 17, 2002. The North Texas system was purchased effective December 31, 2003, and therefore, the Partnership did not record any results of operations from this system in 2003. Comparative results for 2001 include only one month of operations from the East Texas system, and comparative results for 2002 include less than three months of operations from the Midcoast system.

	Year ended December 31,		
	2003	2002	2001
	(dollars in millions)		
Operating revenues	$ 1,846.8	$ 702.2	$ 29.0
Cost of natural gas	$(1,693.3)	$(635.2)	$(26.3)
Operating and administrative	(81.0)	(34.5)	(1.8)
Depreciation and amortization	(24.1)	(12.3)	(0.8)
Expenses	$(1,798.4)	$(682.0)	$(28.9)
Operating income	$ 48.4	$ 20.2	$ 0.1

The table below indicates the average daily volumes for each of the major systems in the Partnership's Gathering and Processing segment during each of the years ending December 31, 2003 and 2002, in million British thermal units per day. The Anadarko, Northeast Texas and South Texas systems were acquired in October 2002. The full year volume data for 2002 is shown for informational purposes and includes data from the records of the previous owner, the General Partner.

	2003 Average MMBtu/d	2002 Average MMBtu/d
East Texas	446,000	405,000
Anadarko	256,000	203,000
Northeast Texas	133,000	146,000
South Texas	38,000	13,000
Total	873,000	767,000

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

Gathering and Processing results of operations improved due to the full year impact of the Midcoast assets and increased volume of natural gas on the East Texas system.

Compared with 2002, natural gas volumes on the gathering and processing assets increased approximately 14% from 767,000 MMBtu/d to 873,000 MMBtu/d. Increased drilling activity by natural gas producers due to higher natural gas prices is a key contributor to volume growth. In addition, the Partnership has undertaken modest expansions of its facilities to handle increased customer volumes. The Northeast Texas system shows a modest decline in volumes partially due to low levels of natural gas drilling in its service area that are not offsetting natural production declines in the area. Drilling near these assets is expected to increase to a level, which should result in a lesser decline or keep production levels flat in the near future.

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

Keep-whole processing for the Partnership is mostly attributable to the Anadarko and East Texas systems. The Partnership's keep-whole processing is a small but variable element of the gathering and processing segment's operating income. During 2003, operating income associated with keep-whole processing was approximately $1.9 million. This compares to operating income of $48.4 million for the gathering and processing 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.

The Partnership estimates that a $0.05 per MMBtu change in keep-whole processing operating revenues less cost of natural gas would increase or decrease total segment operating income by approximately $4.0 million. A 50,000 MMBtu/d change in gathering volume will increase or decrease operating income by approximately $6.0 million. These estimates may vary depending upon the pipeline system to which they relate, competition, other factors and are subject to variability.

Natural Gas Transportation

The Natural Gas Transportation segment was established upon the acquisition of the Midcoast system on October 17, 2002, and its results of operations are included in the Partnership's results since that date. The Natural Gas Transportation segment results for 2003 reflect a full year's contribution to the Partnership compared with less than three months of results in 2002.

	Year ended December 31,		
	2003	**2002**	**2001**
	(dollars in millions)		
Operating revenues	$ 117.7	$ 19.8	$ —
Cost of natural gas	$ (67.6)	$ (8.6)	$ —
Operating and administrative	(21.3)	(4.5)	—
Depreciation and amortization	(13.6)	(2.8)	—
Expenses	$(102.5)	$(15.9)	$ —
Operating income	$ 15.2	$ 3.9	$ —

The table below indicates the average daily volumes for each of the major systems in Partnership's Natural Gas Transportation segment during each of the years ending December 31, 2003 and 2002, in million British thermal units per day. The UTOS, Midla, AlaTenn, KPC, Bamagas and other major intrastate systems were acquired in October 2002. The full year volume data for 2002 is shown for informational purposes and includes data from the records of the previous owner, the General Partner.

	2003 Average	2002 Average
	(MMBtu/d)	
UTOS	213,000	275,000
MidLa	108,000	91,000
AlaTenn	61,000	54,000
KPC	53,000	40,000
Bamagas	14,000	16,000
Other Major Intrastates	182,000	184,000
Total	631,000	660,000

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

Results of operations for the Natural Gas Transportation segment improved in 2003 due to the full year contribution of the Midcoast assets. Performance of the Natural Gas Transportation segment depends largely upon revenues derived from reserved pipeline capacity. Natural gas transportation 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 have 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. The Partnership is exploring alternative customer connections to increase the utilization of this system. High natural gas prices have impacted the anticipated development of increased natural gas demands expected in the Tennessee River Valley area and are a factor in lower utilization of the Partnership's 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

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

The Marketing segment's results for 2003 reflect a full year's contribution to the Partnership compared with less than three months of results in 2002.

	Year ended December 31,		
	2003	2002	2001
	(dollars in millions)		
Operating Revenues	$ 863.6	$ 129.2	$—
Cost of natural gas	$(851.8)	$(126.9)	$—
Operating and administrative	(2.2)	(0.5)	—
Depreciation and amortization	(0.2)	—	—
Expenses	$(854.2)	$(127.4)	$—
Operating income	$ 9.4	$ 1.8	$—

Operating income for the Marketing segment was $9.4 million for the year ended December 31, 2003, compared with $1.8 million for 2002. 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 due to the settlement of disputed amounts, which is included in the Consolidated Statement of Income as a reduction of 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 the Partnership's wholesale customers and creates the opportunity to optimize transportation and storage agreements.

Corporate

Interest expense was $85.0 million in 2003 compared with $59.2 million in 2002 and $59.3 million in 2001. The $25.8 million increase 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. This was partially offset by a decrease in average borrowing rates that has occurred since the end of 2001. During 2003, the Partnership issued $400.0 million in principal amount of senior notes and repaid $311.0 million in loans from the General Partner and affiliates.

Interest expense in 2002 was approximately the same as in 2001 as higher average debt balances were more than offset by lower interest rates and higher interest capitalized on construction projects due to the Terrace expansion program in 2002.

Liquidity and Capital Resources

General

The Partnership believes that it will continue to have adequate liquidity to fund future recurring operating and investing activities. The primary cash requirements for the Partnership consist of normal operating expenses, maintenance and expansion 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 bank credit facilities, i-unit payment-in-kind distributions in lieu of cash and the issuance of additional debt and equity securities, including common and i-units. The Partnership's ability to complete future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time.

On June 30, 2003, the Partnership filed a universal shelf registration statement with the SEC. The Partnership may offer and sell debt securities or Class A Common Units from time to time up to a total of $1.5 billion, with the amount, price and terms to be determined at the time of the sale. The Partnership expects 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.

In December 2003 and January 2004, the Partnership issued an additional 5.45 million Class A Common Units under its universal shelf registration, which generated net proceeds of $262.0 million, net of underwriters' discounts, commissions and issuance expenses. 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 facility of approximately $100.0 million and to pay the December 15, 2003 sinking fund payment of $31.0 million on the Partnership's First Mortgage Notes.

In January 2004, the Partnership issued $200.0 million in principal amount of 4% Senior Notes due 2009 under its universal shelf registration, from which it received net proceeds of approximately $198.4 million after offering expenses. The proceeds were used to repay a portion of the amount outstanding under the Partnership's 364-day revolving credit facility.

After giving effect to the Class A Common Unit Issuance in December 2003 and January 2004, and the debt issuance in January 2004, approximately $1,025.9 million in debt securities or Class A Common Units are available for issuance under the existing universal shelf registration statement.

Summary of Obligations and Commitments

The following table summarizes the Partnership's obligations and commitments at December 31, 2003:

	Payment Due By Period				
	Total	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**After 5 Years**
	(dollars in millions)				
Contractual Obligations					
Long-Term Debt	$1,401.8	$246.0	$302.0	$62.0	$791.8
Right-of-way (1)	54.0	1.8	3.7	3.5	45.0
Operating Leases	20.7	3.9	7.9	5.4	3.5
Power and other purchase commitments	19.1	12.9	6.2	—	—
Total Contractual Cash Obligations	$1,495.6	$264.6	$319.8	$70.9	$840.3

(1) Right of way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipelines. For purposes of this table, the Partnership has estimated its remaining life to be 25 years.

Operating Activities

Net cash provided by operating activities was $132.1 million in 2003 compared with $200.6 million in 2002. An improvement in net income in 2003 compared with 2002 of $33.6 million reflects the full year contribution by the Midcoast system as well as stronger performance on the Lakehead and East Texas systems. This was offset by the overall net decrease for changes in balances for working capital items included in operating activities of $122.1 million. The change was primarily the result of accrued gas receivables and payables changes due to the increased sales volumes and gas prices in 2003 compared with 2002, a deposit of $13.1 million made in December 2003, related to the Mid-Continent asset acquisition that closed on March 1, 2004, as well as the result of timing differences in the collection on and payment of the Partnership's current accounts.

At December 31, 2003, cash and cash equivalents totaled $64.4 million, an increase of $4.1 million from December 31, 2002. Of this amount, $55.8 million was available for cash distributions to unitholders. Of the cash available for distribution, $9.3 million was retained from i-unit holders and $0.2 million was retained from the General Partner by the Partnership for use in its business. The fourth quarter distribution to unitholders and the General Partner of $46.8 million ($0.925 per unit), which includes the effects of $0.5 million for the exercise of the over-allotment option in January 2004, was paid on February 13, 2004.

Investing Activities

Net cash used in investing activities was $431.0 million for the year ended December 31, 2003, compared with $557.2 million for the prior year. The $126.2 million decrease in funds utilized in investing activities was attributable to two items:

- Lower cash out flows made for strategic acquisitions in 2003 compared with 2002 of $55.0 million. During 2003, the Partnership acquired the North Texas system for cash paid of $249.7 million and paid post-closing adjustments to the General Partner related to the Midcoast acquisition of $43.8 million, compared with the acquisition of the Midcoast system during 2002 for cash paid of $344.4 million; and
- A decrease in additions to property, plant and equipment in 2003 of $85.4 million primarily due to a significant amount of construction activity during 2002 related to the Terrace Phase III expansion program.

During 2003, the Partnership spent $129.3 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 undertaken to enable the Partnership's 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 the Partnership to respond to developing industry and government standards and the changing service expectations of its customers. The Partnership's core maintenance capital expenditures increased to $28.8 million for 2003 compared with $14.2 million for 2002, due to the full year impact of the Midcoast system acquisition in 2003.

Financing Activities

Net cash provided by financing activities was $303.0 million in 2003, compared with $376.7 million in 2002. The decrease of $73.7 million from 2002 is primarily due to higher net repayments to the General Partner and affiliates and an increase in the distributions to partners. In May 2003, the Partnership issued $400.0 million in aggregate principal of senior unsecured notes and used the net proceeds to repay existing loans from Enbridge affiliates and amounts outstanding under the Partnership's credit facilities. Cash distributions to partners increased to $156.7 million in 2003 compared with $137.3 million in 2002. The increase in distributions was due to:

- an increase in the per unit cash distributions paid, from $3.60 per unit in 2002 to $3.70 per unit in 2003;
- 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 2003, working capital decreased by $118.7 million to a working capital deficit of $179.8 million, primarily due to the inclusion of the $215.0 million balance of the Partnership's 364-day credit facility in current liabilities in 2003, compared with classifying it as long-term debt in 2002. This balance was recorded as a current liability, as the Partnership's lender granted a three-month extension to the existing maturity date of January 2004 to facilitate the credit review process and better coordinate the annual request for extension.

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, $100.0 million to reduce borrowings under the Partnership's three-year term facility and $31.0 million to pay the December 15, 2003 sinking fund payment on the First Mortgage Notes. The remainder of the net proceeds was used to fund a portion of the North Texas system acquisition. In addition to the proceeds generated from the unit issuances, the General Partner contributed $5.1 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 by $102.4 million and an affiliate loan by $63.1 million. In addition to the proceeds generated from the unit issuances, the General Partner contributed $3.5 million to the Partnership to maintain its 2% general partner interest in the Partnership.

In March 2002, the Partnership issued 2.26 million Class A Common Units at $42.75 per unit. The net proceeds from the offering were $93.3 million and were used to repay indebtedness.

On October 17, 2002, the Partnership issued 9,000,000 i-units to Enbridge Management for net proceeds of $330.8 million. The Partnership used the net proceeds to repay debt owed to affiliates that was assumed in connection with the acquisition of the Midcoast system.

Cash Distributions

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

Enbridge Management, as owner of the i-units, 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 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. The Partnership will retain and use that cash in its business.

During 2003, the Partnership distributed a total of 833,515 i-units through quarterly distributions to Enbridge Management, compared with 228,654 in 2002. The increase was the result of a full year's distributions in 2003, compared with one quarter in 2002, as the i-units were issued in October 2002. The Partnership retained $35.4 million in 2003 related to the i-unit distributions compared with $8.1 million in 2002.

Credit Facilities and Debt

The Partnership's credit facilities and debt consist of the following:

	December 31, 2003	December 31, 2002
	(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	246.0	31.0
Long-term debt:		
364-day credit facility	—	212.0
Three-year term facility	240.0	252.0
First Mortgage Notes	217.0	248.0
7.90% senior notes due 2012	100.0	100.0
4.75% senior notes due 2013	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	—
Unamortized discount	(1.2)	(0.6)
Total long-term debt	$1,155.8	$1,011.4
Loans from Enbridge affiliates	$ 133.1	$ 444.1
Total debt	$1,534.9	$1,486.5

Credit Facilities. In January 2003, the Partnership amended and restated the terms of its two unsecured revolving credit facilities, which were originally entered into in January 2002. The facilities consist of a $300.0 million three-year term facility (the "Three-year Facility"), which matures in 2006 (subject to extension as provided in the facility) and a $300.0 million 364-day facility (the "364-day facility"), which matures in April 2004 (subject to a one-year term-out option and extension as provided in the facility). Interest is charged on amounts drawn under each of these facilities at a variable rate equal to the Base Rate or a Eurodollar rate as defined in the facility agreements. In the case of a 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 each facility whether or not drawn. The facility fee varies depending on the Partnership's credit rating. As of December 31, 2003, the facility fees on the three-year and 364-day facilities were 0.20% and 0.15%, respectively. These credit facilities contain restrictive covenants that require that the Partnership maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 4.75 times, each as defined in the facility agreements. The facility agreements also place 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.

As of December 31, 2003, $215.0 million was drawn on the Partnership's 364-day facility at a weighted average interest rate of 1.90% and $240.0 million was drawn on the Partnership's three-year facility at a weighted average interest rate of 1.84%.

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 the Partnership, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. The Partnership believes these issuance tests will not negatively impact its ability to finance future expansion projects. Under the First Mortgage Note Agreements, the Partnership cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash for the immediately preceding calendar quarter. If the notes were to be paid prior to their stated maturities, the First Mortgage Note Agreements provide for the payment of a redemption premium by the Partnership.

Senior Notes. In addition to the $300.0 million of Senior Unsecured Notes previously outstanding, on May 27, 2003, the Partnership issued $200.0 million in aggregate principal amount of its 4.75% Notes due 2013 and $200.0 million in aggregate principal amount of its 5.95% Notes due 2033 in a private placement. The Partnership used the proceeds of approximately $396.3 million, net of expenses of approximately $3.0 million, to repay loans from affiliates of the Partnership and other bank debt. The Partnership recorded a discount of $0.7 million in connection with the issuance of the Notes. On June 30, 2003, the Partnership completed a Form S-4 with the SEC, which registered the exchange of the unregistered Notes for publicly registered Notes.

All of the 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 Enbridge affiliates. As of December 31, 2003, the Partnership had $133.1 million in debt outstanding under a note to an affiliate of the General Partner. This note relates to debt assumed by the Partnership 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 the First Mortgage Notes issued by the Partnership or defaults under the Partnership's three-year term facility and 364-day credit facility. The note is subordinate to the Partnership's credit facilities and other senior indebtedness.

Off-Balance Sheet Arrangements

The Partnership has no off-balance sheet arrangements.

Credit Ratings

In May 2003, Standard & Poor's and Moody's assigned the ratings for the Partnership's senior unsecured debt obligations of BBB and a Baa2, respectively. In May 2003, Moody's also lowered its senior unsecured debt rating of the Lakehead Partnership, a wholly-owned subsidiary of the Partnership, from A3 to Baa1. Standard & Poor's rating for the Lakehead Partnership's senior unsecured debt obligations was unchanged during 2003 at BBB+.

Cash Requirements for Future Growth

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 risk profiles similar to the Partnership's current businesses. The Partnership 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. The Partnership expects this trend to continue and believes it is well positioned to participate in these opportunities. The Partnership will seek opportunities throughout the United States, particularly in the

U.S. Gulf Coast area, where asset acquisitions are anticipated in and around its recently acquired natural gas gathering, processing, and transportation businesses.

The Partnership expects that the funds needed to achieve the objective of 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, including common units and i-units.

The Partnership's acquisition of the North Texas system on December 31, 2003 for $249.7 million was funded with borrowings under the Partnership's 364-day revolving credit facility and three-year term facility. The additional debt will result in increased debt service costs in the future. To the extent that proceeds from future equity offerings are used to reduce the principal amount of debt, the Partnership's interest expense will be reduced. To the extent that the Partnership refinances its existing debt with new debt, its interest expense will generally be affected by differences in interest rates charged on the existing debt versus the new debt and by any fees associated with the new debt.

On December 22, 2003, the Partnership entered into definitive agreements to acquire crude oil pipeline and storage systems from Shell Pipeline Company LP and Shell Oil Products US ("Shell") for $115.0 million, excluding customary closing adjustments for working capital and other items. The asset purchase closed on March 1, 2004. The Partnership funded the acquisition through its existing credit facilities.

Distributions. For the year ended December 31, 2003, the declared annual distribution rate was $3.70 per unit, compared with $3.60 per unit for the year ended December 31, 2002. An increase in the Partnership's distribution rate will result in additional cash payments to existing unitholders and the General Partner. As well, an increase in the number of common units eligible for cash distributions will result in higher total distribution payments. The Partnership expects that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, the Partnership may temporarily borrow under its credit facilities for the purpose of paying cash distributions until the full impact of operations is realized.

Capital Spending. At December 31, 2003, the Partnership had $3.7 million in estimated outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as Property, Plant and Equipment.

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.

Capital expenditures are categorized by the Partnership 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 the Partnership to respond to governmental regulations and developing industry standards.

In 2004, the Partnership anticipates capital expenditure spending to approximate:

	(dollars in millions)
System enhancements	$122.0
Core maintenance activities	33.0
Lakehead System expansion projects	40.0
East Texas expansion	105.0
	$300.0

Excluding major expansion projects and acquisitions, ongoing capital expenditures are expected to average approximately $98.0 million annually (approximately 35% for core maintenance and 65% for system enhancements).

The Partnership anticipates funding the expenditures temporarily through its bank credit facilities, with permanent debt and equity funding being provided when appropriate.

The Partnership expects to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of the 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.

Included in the anticipated capital expenditures spending for system enhancements in 2004 is approximately $25.0 million of capital expenditures to ensure regulatory compliance on the Lakehead system. This spending is for pressure testing of the Lakehead system to establish operating pressures in excess of operating limits that would otherwise be allowed under current circumstances.

Subsequent Events

Class A Common Unit issuance

In January 2004, the Partnership issued an additional 450,000 Class A Common Units to its underwriters pursuant to the exercise of the over-allotment option as part of the December 2003 Class A Common Unit issuance. This resulted in additional proceeds to the Partnership, net of underwriters' fees and discounts, commissions and issuance expenses, of approximately $21.7 million. The proceeds were used to reduce amounts outstanding under the Partnership's revolving credit facilities.

Distribution Declaration

On January 22, 2004, the Partnership's Board of Directors declared a distribution payable on February 13, 2004, to unitholders of record as of February 2, 2004, of its available cash of $55.8 million at December 31, 2003, or $0.925 per common unit. Of this distribution, $9.3 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.

Senior Notes offering

In January 2004, the Partnership issued $200 million in principal amount of 4% Senior Notes due 2009, from which it received net proceeds of $198.4 million after offering expenses. The proceeds were used to repay a portion of the amount outstanding under the 364-day revolving credit facility.

Mid-Continent Liquids System

On December 22, 2003, the Partnership entered into definitive agreements to acquire crude oil pipeline and storage systems from Shell Pipeline Company LP and Shell Oil Products US ("Shell") for

$115.0 million, excluding customary closing adjustments for working capital and other items. The asset purchase closed on March 1, 2004. The assets acquired serve refineries in the Mid-Continent from the Cushing, Oklahoma hub, and consist of the following:

- The 433-mile Ozark pipeline that currently transports approximately 170,000 barrels of crude oil per day from Cushing to Wood River, Illinois;
- A 1.2 million barrel storage terminal located in El Dorado, Kansas;
- The 47-mile West Tulsa pipeline that currently transports approximately 55,000 barrels per day to two refineries in Oklahoma; and
- The storage terminal at Cushing, which is one of the largest terminal facilities in North America with 8.3 million barrels of storage capacity.

These systems provide cash flows primarily from toll or fee-based revenues from a combination of regulated assets and contracted unregulated assets and are expected to be accretive to the Partnership's distributable cash flow. The assets are consistent with the Partnership's core operating expertise in crude oil pipelines and the throughput originates from sources of supply different from those on its other crude oil systems, providing increased diversity in the Partnership's sources of cash flow.

Enbridge concurrently acquired Shell's Patoka West Tank Farm. These assets complement Enbridge's initiative to access new markets for Canadian crude oil. The Partnership expects to benefit from the market access initiative by facilitating throughput on the Lakehead system.

Other Matters

Future Prospects

The Partnership believes that its financial performance will continue to improve in 2004 as a result of increased capacity utilization on the Lakehead system, combined with the contributions from the recently acquired North Texas and Mid-Continent Liquids systems.

Liquids Transportation

Average daily crude oil deliveries on the Lakehead system are expected to increase by 100,000 bpd during 2004, from 1.354 million barrels per day in 2003 to approximately 1.45 million bpd in 2004. The majority of the growth in deliveries is expected to come from a full year's production from the AOSP project that commenced during 2003. The AOSP is sponsored by two multinational integrated oil companies and an independent oil and gas company. While start-up problems delayed the expected incremental supply from the AOSP during 2003, the Partnership anticipates production to increase significantly in 2004 to meet the AOSP sponsor's expectations. This increase in supply is expected to result in higher deliveries on the Lakehead system.

Future prospects for the 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 estimated reserves of Saudi Arabia. Therefore this resource is expected to be an important crude oil supply for North America in the coming decades. Recognizing this, a number of major oil companies have announced projects requiring investments of approximately $30 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 the Lakehead system.

There are several major oil sands projects 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 2005-2006. In combination, these projects are expected to provide more than 100,000 bpd of supply. In addition to the Alberta oil sands, Canada has substantial conventional crude oil resources. Conventional crude 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."

Recognizing the need to expand beyond the Lakehead system's traditional markets, Enbridge and the Partnership 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. Enbridge and the Partnership 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 200,000 bpd into the major oil hub at Cushing by 2005. The Partnership expects 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 Spearhead. The second step was the Partnership's announcement in October 2003 of plans to extend the Lakehead system with a new 250,000 to 400,000 bpd pipeline to serve the large Wood River, Illinois refining center by 2007. This "Southern Access" project would intersect with Spearhead to offer customers delivery options to Cushing and Chicago, in addition to Wood River.

The Partnership closed its previously announced acquisition of Shell's Mid-Continent liquids systems, centered around the major Cushing crude oil hub, on March 1, 2004. The pipeline assets provide U.S. domestic and imported feedstock to Mid-Continent area refineries. The Partnership also acquired considerable tank storage capacity, mainly at the Cushing hub. The Cushing storage capacity in excess of operating requirements is contracted under term agreements. These assets provide basin diversification for the Partnership, because the crude oil shipped is not sourced from the western Canadian basin, as are the bulk of the Lakehead system deliveries.

Natural Gas—Gathering and Processing, Transportation and Marketing

The Partnership's 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 the Partnership's natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas served by the Partnership. During 2003, increased drilling in the areas where the Partnership's 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 750 MMcf/d in late 2003. The Barnett Shale is a prominent new natural gas development within the Fort Worth Basin, not previously accessed by the Partnership's system. To address this opportunity, the Partnership acquired the North Texas system in a transaction that closed on December 31, 2003. The acquired facilities will provide approximately 220 MMcf/d of processing capacity. The Barnett Shale is being actively developed, and the Partnership anticipates that throughput on the North Texas system will increase modestly in each of the next several years.

The Partnership has announced proposed construction of 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. Following a successful open season for the proposed East Texas line, preliminary volume commitments were obtained from natural gas producers, and the Partnership expects to proceed with construction to bring the system on stream in mid 2005. The Partnership is pursuing options to connect production from North Texas to the new transmission line and provide Carthage access for gas producers in that area.

Growth by Acquisitions

Acquisitions are expected to play a role in the achievement of financial targets of the Partnership for 2004. In general, these acquisitions are expected to be in or near areas where the Partnership already operates and will present the best opportunities for consolidation savings and enhancement of the Partnership's market position. In addition to the previously announced Mid-Continent crude oil acquisition, approximately $175.0 million of capital has been budgeted for additional acquisitions in 2004.

The Partnership also will evaluate more significant acquisitions. Subject to financing capability, Enbridge plans to use the Partnership as its primary vehicle for acquiring mature energy delivery assets, particularly in the Gulf Coast region of the United States. The Partnership 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

The Partnership has modestly grown its cash distributions over the last several years. Cash distributions would likely have increased more were it not for lower utilization of the Lakehead system expansions than anticipated when the Partnership committed to the expansions in the late 1990's. Increased utilization of the Lakehead system and the approximately $415.0 million Terrace expansion program are 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, such as the Southern Access project, that will grow the earnings and cash flow of the Partnership. Selected acquisitions and growth of the natural gas segments are also expected to contribute to improved near-term performance of the Partnership.

Regulatory Matters

KPC System

From 1998, when KPC became subject to the FERC jurisdiction, until November 9, 2002, when KPC's rate case rates became effective, the FERC established initial rates based upon an annual cost of service of approximately $31.0 million. Since that time, these initial rates have been the subject of various ongoing challenges that remain unresolved.

The United States Court of Appeals for the D.C. Circuit issued an order on August 12, 2003, vacating the FERC's 2001 remand order and 2002 rehearing order and remanded the issue of KPC's initial rates back to the FERC with directions that the FERC address the question of an appropriate rate refund. In prior KPC orders in this proceeding, the FERC determined that it had no authority to impose a refund condition on initial rates. On October 3, 2003, KPC filed a pleading at the FERC requesting the issuance of an order finding that it had no refund obligation and requesting termination of the proceedings on remand. There are other actions and administrative proceedings that may be undertaken in connection with the Court's determination. The outcome of KPC's motion or any proceedings, including the amount of any refunds that may be ordered, is uncertain. If the FERC determines refunds are required, after all administrative options and court appeals are exhausted, the amount of the refunds may range from zero to $9.0 million.

Liquids Petroleum Pipelines

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 Producers Price Index for Finished Goods minus 1% (PPI-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 PPI-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 issue has not yet been resolved.

Recent Accounting Developments

In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities*." This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. In particular, this statement: (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative discussed in paragraph 6(b) of SFAS No. 133, (2) clarifies when a derivative contains a financing component, (3) amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, and (4) amends certain other existing pronouncements. The new standard was adopted July 1, 2003, and did not have a significant impact on the Partnership's financial position, results of operations, or cash flows.

In January 2003, the FASB issued Interpretation No. 46, "*Consolidation of Variable Interest Entities*" ("FIN 46"). FIN 46 requires an investor with a majority of the variable interests in a variable interest entity to consolidate the entity and also requires majority and significant variable interest investors to provide certain disclosures. A variable interest entity is an entity in which the equity investors do not have a controlling interest or the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support form the other parties. In December 2003, the FASB completed deliberations of proposed modifications to FIN 46 resulting in multiple effective dates based on the nature as well as the creation date of the variable interest entity. However, the revised Interpretation must be applied no later than the first quarter of fiscal year 2004. There was no impact on the Partnership's consolidated financial position or results of operations as a result of the adoption of FIN 46.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate and Foreign Exchange Risk

To the extent the amounts drawn under its revolving credit facilities carry a floating rate of interest, the Partnership's earnings and cash flow 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. The Partnership does not have any material exposure to movements in foreign exchange rates as virtually all of its revenues and expenses are denominated in U.S. dollars. To the extent that a material foreign exchange exposure arises, the Partnership intends to hedge such exposure using forward or other financial derivative contracts.

The table below summarizes, as of December 31, 2003, the Partnership's 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

	2004	2005	2006	2007	2008	There-after	Total	Fair Value
				(dollars in millions)				
Liabilities								
Fixed Rate:								
First Mortgage Notes	$ 31.0	$31.0	$ 31.0	$ 31.0	$31.0	$ 93.0	$248.0	$303.0
Interest Rate	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	—	—
Senior Unsecured Notes	—	—	—	—	—	$ 700.0	$700.0	$739.0
Average Interest Rate	—	—	—	—	—	6.20%	—	—
Variable Rate:								
Revolving Credit Facility	$215.0	—	$240.0	—	—	—	$455.0	$455.0
Average Interest Rate	1.90%	—	1.84%	—	—	—	—	—
Interest Rate Derivatives								
Interest Rate Swaps:								
Variable to Fixed	$150.0	—	—	—	—	—	$150.0	—
Average Pay Rate	1.36%	—	—	—	—	—	—	—
Fixed to Variable	—	—	—	—	—	$ 125.0	$125.0	$ 4.2
Average Pay Rate	—	—	—	—	—	Libor—0.22%	—	—
Treasury Lock	$104.0	—	—	—	—	—	$104.0	$ 1.0
Pay Rate	3.19%	—	—	—	—	—	—	—

Commodity Price Risk

The Partnership's earnings and cash flows associated with its liquids transportation systems are not significantly impacted by changes in commodity prices, as the Partnership does not own the crude oil and NGLs it transports. However, the Partnership has 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 the Partnership transports.

A portion of the Partnership's earnings and cash flows in its natural gas segments are exposed to movements in the prices of natural gas and NGLs. The Partnership has 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, the Partnership may not enter into derivative instruments for speculative purposes. All financial derivative transactions must be undertaken with creditworthy counterparties. As at December 31, 2003, all financial counterparties were rated at least "A" by all major credit rating agencies.

Natural Gas Transportation and Marketing

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 at December 31, 2003 and 2002:

System	Maturity Dates	Notional MMBtu	Fair Value 2003	Fair Value 2002
			(dollars in millions)	
East Texas system	2004-2011	26,000	$(19.9)	$ (6.1)
Northeast Texas system	2004-2012	42,000	$(44.9)	$(19.1)
Midcoast system	2004	600	$ (0.7)	$ (0.3)
Marketing	2004-2007	38,000	$ 2.0	$ 2.1

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 (from the last quarter-end) of these derivative instruments is booked to the income statement. For the years ended December 31, 2003 and 2002, the Partnership recorded losses of $0.3 million and zero, respectively, in the Consolidated Statements of Income as part of the cost of natural gas expense, to account for changes in the fair value related to these basis swaps in mark to market changes related to the Marketing segment.

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, 2003 and 2002:

System	Maturity Date	Notional Barrels	Fair Value 2003	Fair Value 2002
		(in millions)	(dollars in millions)	
Northeast Texas system	2004	0.5	$(2.4)	$(2.5)
Midcoast system	2004	0.1	$(0.2)	$(0.1)
East Texas system	2004	0.5	$(0.8)	$ —
North Texas system	2004	0.8	$(1.1)	$ —

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements of the Partnership, together with the notes thereto and the independent auditors' report thereon, and unaudited supplementary information, appear on pages F-2 through F-20 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

The Partnership and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that the Partnership is able to record, process, summarize and report the information required in the Partnership's 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, 2003. 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 behalf of the Partnership. 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.

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, 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 by, and may be removed by, Enbridge Pipelines, as the sole stockholder of the General Partner. All directors of Enbridge Management are elected annually by, and may be removed by, the General Partner, as the sole holder of the 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	57	Director
P.D. Daniel	57	Director
E.C. Hambrook	66	Director
M.O. Hesse	61	Director
G.K. Petty	62	Director
D.C. Tutcher	55	President and Director
J.R. Bird	54	Group Vice President — Liquids Transportation and Director
G.L.Sevick	48	Vice President — Liquids Transportation, Operations
M.A. Maki	39	Vice President — Finance
T.L. McGill	49	Vice President — Commercial Activity & Business Development
A.D. Meyer	47	Vice President — Liquids Transportation, Technology
R.L. Adams	39	Vice President — Operations and Technology
L.S. Cruess	46	Treasurer
J.L. Balko	38	Controller
E.C. Kaitson	47	Corporate Secretary

J.A. Connelly was elected a director of the General Partner in January 2003 and serves on its Audit, Finance & Risk Committee. Mr. Connelly served as 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 served as Chairman of the General Partner from July 1996 until July 1999. 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 General Partner in April 2003 and serves as a member of its Audit, Finance & Risk Committee. Ms. Hesse is President and CEO of Hesse Gas Company. 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 Group 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.

G.L. Sevick was elected Vice President—Liquids Transportation, Operations of the General Partner in June 2001. He has served as Vice President, Operations for Enbridge Pipelines since 1999.

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. 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 October 2003. He also continues to serve as Vice President, Technology, Enbridge Transportation—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 Technology 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.

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 July 2002. Prior to that time, she served as Chief Accountant of the General Partner from October 1999 to June 2002 and served in managerial positions in accounting with Enbridge Pipelines since January 1998 to September 1999.

E.C. Kaitson has served as Corporate Secretary of the General Partner since November 2001. 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) Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, executive officers and 10% beneficial owners to file with the SEC reports of ownership and changes in ownership of the Partnership's equity securities and to furnish the Partnership with copies of all reports filed. The Partnership is a limited partnership and has no officers or directors of its own. Based solely on the review of the reports furnished, the Partnership believes that, during fiscal year 2003, all Section 16(a) filing requirements applicable to the directors and officers of the General Partner, and greater than 10% beneficial owners of the Partnership were met, except that SEC Form 3, Initial Statement of Beneficial Ownership of Securities, for A.D. Meyer was filed late.

(c) Governance Matters

As the Partnership is a limited partnership, the listing standards of the NYSE do not require that the Partnership or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

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 Securities Exchange Act of 1934, as amended. The members of the Audit Committee are M.O. Hesse, E.C. Hambrook, G.K. Petty and J.A. Connelly. No member of the Audit Committee serves on the audit committee of more than three public companies. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the independent auditors. 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 current version of the charter of the Audit Committee is filed as an exhibit to this annual report on Form 10-K and is available on the Partnership's website at *www.enbridgepartners.com*. The Charter of the Audit Committee complies with the listing standards of the New York Stock Exchange currently applicable to the Partnership. The Charter is under review for compliance with newly adopted rules of the NYSE with which the Partnership must comply by October 31, 2004.

The Partnership'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.

The Partnership'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 the Partnership's Audit Committee may do by writing in care of Chairman, Audit Committee, c/o Enbridge Energy Partners, L.P., 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 its 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 the Partnership's website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. The Partnership intends to post on its website any amendments to or waivers of its 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.

The Partnership also has a Statement of Business Conduct applicable to all employees, officers and directors of Enbridge Management. A copy of the Statement of Business Conduct is available on the Partnership's website at *www.enbridgepartners.com*. The Partnership intends to post on its website any amendments to or waivers of its 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 served as the presiding director at those executive sessions. Persons wishing to communicate with the Partnership'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 total annual and long-term compensation for all services rendered in all capacities to the Partnership and Enbridge Management for the fiscal year ended December 31, 2003 and 2002, of the Chief Executive Officer and the other most highly compensated executive officers (the "Named Executive Officers"). No allocation of compensation is made between the Partnership and Enbridge Management because the Partnership bears an allocable portion of these officers' total compensation that is based approximately on the percentage of time each of these officers devotes 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. Compensation of the Named Executive Officers for years prior to 2002 is not provided because it was previously not reported.

Summary Compensation Table

Name & Principal Position	Year	Salary	Bonus	Other Annual Compensation (1)(2)	All Other Compensation (3)	Approximate Percentage of Time Devoted to Enbridge Management and the Partnership
D.C. Tutcher	2003	$309,750	$235,000	$35,000	$10,000	80
President	2002	$296,250	$ 91,000	$40,000	$11,625	80
T.L. McGill	2003	$221,000	$ 89,800	$20,000	$ 6,361	90
Vice President—Commercial Activity & Business Development	2002	$182,474	$ 34,000	$16,886	$ 4,193	90
E.C. Kaitson	2003	$168,000	$ 35,400	$10,000	$ 8,375	90
Secretary	2002	$161,250	$ 18,200	$10,000	$ 8,990	90
M.A. Maki	2003	$161,750	$ 71,400	$20,000	$ 7,100	90
Vice President—Finance	2002	$136,762	$ 55,700	$25,978	$ 6,950	90
R.L. Adams	2003	$151,000	$ 54,100	$26,229	$ 7,568	90
Vice President—Operations and Technology	2002	*	*	*	*	*

* Not elected as an officer until 2003

Notes:

(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) 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. 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. 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 2003, Mr. Tutcher received perquisites and other personal benefits totaling $35,000, of which $30,000 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 $26,229, of which $17,500 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 2003, Enbridge made contributions of $10,000, $6,361, $7,100, $8,375 and $7,568, respectively, to the 401(k) Plan for the benefit of Mr. Tutcher, Mr. McGill, Mr. Maki, Mr. Kaitson, and Mr. Adams.

Compensation Committee Interlocks and Insider Participation

Neither Enbridge Management nor the General Partner have a compensation committee, therefore, all decisions related to executive compensation matters are made by a committee of the Board of Directors of Enbridge.

Enbridge has a Human Resources & Compensation Committee (the "Committee") which is presently comprised of the following directors (the date of their appointment to the Committee is listed after their name): D.A. Arledge (January 1, 2002), E.S. Evans (May 3, 2002), W.R. Fatt (Chair) (May 3, 2002), R.L. George (April 29, 1999), R.W. Martin (February 1, 2001) and D.J. Taylor (May 2, 1996). During 2003, no member of the Committee was an officer or employee of Enbridge or any of its subsidiaries, or had any relationship with Enbridge except as director, other than D.J. Taylor, who was a non-executive officer holding the office of Chair of the Board. Effective February 24, 2004, the Board of Directors of Enbridge revised bylaw No. 1 of the corporation so that Chair of the Board is no longer an office of the corporation. Mr. Taylor continues as Chair of the Board of Enbridge, however, effective February 24, 2004, is no longer an officer of the Board.

Stock Options

Options to purchase shares of Enbridge may from time to time be granted by Enbridge to the Partnership's Named Executive Officers, but no portion of any such grant is attributable to services performed for the Partnership or Enbridge Management nor are any expense reimbursements made by the Partnership on account of such options.

Employment Agreements

Messrs. Tutcher and Kaitson have Executive Employment Agreements with Enbridge. The Agreements commenced on May 11, 2001, and continue until the earlier of (i) the date of voluntary retirement in accordance with the retirement policies established for senior employees of Enbridge (ii) the voluntary resignation which is not a constructive dismissal, or (iii) termination based on disability, death, cause or by either party. The Agreements provide that in the event of termination of employment, the executive agrees to keep confidential all information of a confidential or proprietary nature and further agrees not to use such information for personal advantage. The Agreements also provide for a base salary, annual reviews, discretionary raises, participation in short and long-term incentive plans of Enbridge, and severance payments in the amount of two years compensation in the event of termination by Enbridge.

Director Compensation

Enbridge employees who are members of the Board of Directors of the General Partner or Enbridge Management do not receive any additional compensation for serving in those capacities. Members of the Board of Directors of the General Partner and Enbridge Management who are not employees receive an aggregate annual fee of $20,000, paid quarterly, plus $1,000 per day for each meeting attended of the board of directors or committees of the board. In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees and an additional $500 for meetings requiring out of town travel. The director who serves as chairman of the audit committees is paid an additional $5,000 per year and the director who serves as chairman of the boards is paid an additional $10,000 per year, paid quarterly. The

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

Mr. Hambrook served as chairman of a special committee of the Board of Directors of the General Partner in 2002 and 2003, in its capacity as General Partner of the Partnership. The special committee of the Partnership was empowered to act on behalf of the Partnership in its purchase of the Midcoast assets. As compensation, Mr. Hambrook received a fee of $20,000, plus a fee of $1,000 per committee meeting. In addition, he was reimbursed for out-of-pocket expenses in connection with attending special committee meetings and an additional $500 for each meeting requiring out of town travel.

Messrs. Hambrook and Connelly served on pricing committees in 2003 in connection with public offerings to sell limited partnership interests in the Partnership. As compensation for serving on the pricing committees, they each received a fee of $1,000 per meeting.

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 17, 2004, with respect to persons known to the Partnership 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	10,062,170	100.0
Enbridge Energy Company, Inc. . . . . 1100 Louisiana, Suite 3300 Houston, TX 77002	Class B Common Units	3,912,750	100.0
Goldman, Sachs & Co.(1) . . . . The Goldman Sachs Group, Inc. 85 Broad St. New York, N.Y. 10004	Class A Common Units	1,740,639	4.3

(1) Goldman, Sachs & Co. and The Goldman Sachs Group, Inc. reported shared voting power and shared dispositive power with respects to all of such shares in its report on Form SC 13G/A filed February 12, 2004. Goldman, Sachs & Co. and The Goldman Sachs Group, Inc. each disclaim beneficial ownership of the securities beneficially owned by (a) any client accounts with respect to which Goldman, Sachs & Co. or its employees have voting or investment discretion or both, and (b) certain investment entities, of which a subsidiary of The Goldman Sachs Group, Inc. or Goldman, Sachs & Co. is the general partner, managing general partner or other manager, to the extent interests in such entities are held by persons other than The Goldman Sachs Group, Inc., Goldman, Sachs & Co. or their affiliates. The address of Goldman, Sachs & Co. and the Goldman Sachs Group, Inc. is 85 Broad Street, New York, NY 10004.

(b) Security Ownership of Management and Directors

The following table sets forth information as of February 17, 2004, with respect to each class of the Partnership's 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	—	—
G.L. Sevick	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	—	—
L.S. Cruess	Class A Common Units	—	—
J.L. Balko	Class A Common Units	—	—
E.C. Kaitson	Class A Common Units	—	—
All Officers, directors and nominees as a group (15 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, 2003, the General Partner owned 3,912,750 Class B Common Units representing a 7.1% limited partner interest in the Partnership. In addition, the General Partner also owns 1,732,930 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 12.2% of the Partnership and received $33.7 million in cash and incentive distributions.

Interest of Enbridge Management in the Partnership

At December 31, 2003, Enbridge Management owned 10,062,170 i-units, representing an 18.2% limited partner interest in the Partnership. 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'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 the i-units will at all times be equal.

Cash Distributions

As discussed in "Part II, Item 7", the Partnership makes quarterly cash distributions of all of its available cash to the General Partner and the holders of its common units. Under the Partnership Agreement, the 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 2003, incentive distributions paid to the General Partner were approximately $17.4 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 its 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 included elsewhere in this report.

Item 14. Principal Accountant Fees and Services

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

	For the years ended December 31,	
	2003	2002
Audit fees(1)	$ 602,991	$ 881,002
Audit related fees(2)	14,150	—
Tax fees(3)	529,520	537,043
All other fees	—	—
Total	$1,146,661	$1,418,045

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

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

The following documents are filed as part of this Report:

(a) As to financial statements, supplementary information and financial statement schedules, reference is made to "Index Consolidated to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this Report.

(b) The Partnership filed the following reports on Form 8-K during the fourth quarter of 2003:

- A current report on Form 8-K was filed on December 30, 2003, attaching a press release dated December 22, 2003, disclosing the intent to acquire of certain crude oil pipeline and storage systems from Shell;
- A current report on Form 8-K was filed on December 5, 2003, regarding entering into an Underwriting Agreement relating to the offering of up to 5,725,000 units (including an option to purchase up to 725,000 units) representing limited partner interests in the Partnership;
- A current report on Form 8-K was filed on November 24, 2003, attaching a press release dated November 19, 2003, disclosing the execution of a definitive purchase agreement to acquire natural gas gathering and processing assets in North Texas from Cantera Resources Inc., an affiliate of Morgan Stanley Capital Partners;
- A current report on Form 8-K was filed on October 24, 2003, attaching a press release dated October 22, 2003 regarding the financial results for the three and nine months ended September 30, 2003.

(c) 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

Date: March 12, 2004

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on March 12, 2004 by the following persons on behalf of the Registrant and in the capacities indicated.

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

Index to Exhibits

The following Exhibits (numbered in accordance with Item 601 of Regulation S-K) are filed or incorporated herein by reference as part of this Report.

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 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 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 September 24, 2002)
10.5	Second Amendment to Contribution Agreement (Exhibit 99.3 to the Partnership's Current Report on Form 8-K filed October 31, 2002)
10.6	Delegation of Control Agreement (Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q filed 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 November 14, 2002)
10.8	Operational Services Agreement (Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002)
10.9	General and Administrative Services Agreement (Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002)
10.10	Omnibus Agreement (Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q filed 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	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)
10.13	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)

Exhibit Number	Description
10.14	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)
10.15	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)
10.16	Note Agreement and Mortgage, dated December 12, 1991 (Exhibit 10.1 to the Partnership's 1991 Form 10-K)
10.17	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)
10.18	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)
10.19	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)
10.20	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)
10.21	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)
10.22	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 Form 8-K dated October 20, 1998)
10.23	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 Form 8-K dated October 20, 1998)
10.24	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 Form 8-K dated October 20, 1998)
10.25	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 Form 8-K dated November 16, 2000)
10.26	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 Form 8-K dated October 20, 1998)
*10.27	Executive Employment Agreement, dated May 11, 2001, between Dan C. Tutcher, as Executive, and Enbridge Inc., as corporation.
*10.28	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as corporation.
10.29	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 June 30, 2003)
10.30	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 June 30, 2003)

Exhibit Number	Description
10.31	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 June 30, 2003)
10.32	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (Exhibit 99.3 to the Partnership's Form 8-K filed January 9, 2004)
14.1	Code of Ethics for Senior Financial Officers
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.

All Exhibits listed above (with the exception of Exhibits 14.1, 21.1, 23.1, 31.1, 31.2, 32.1, 32.2, and 99.1 which are filed herewith) are incorporated herein by reference to the documents identified in parentheses.

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.

* Management Compensation or Incentive Plan

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 shown in the consolidated financial statements or notes thereto.

Report of Independent Auditors

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

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 consolidated financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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.

As discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of accounting for goodwill and intangible assets effective January 1, 2002.

PricewaterhouseCoopers LLP

Houston, Texas
January 27, 2004, except for
the first two paragraphs of Note 15, as to which the date is
March 1, 2004

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	2003	2002	2001
	(dollars and units in millions, except per unit amounts)		
Operating revenue	$3,172.3	$1,185.5	$342.3
Expenses			
Cost of natural gas	2,612.7	770.7	26.3
Operating and administrative	211.8	144.2	104.5
Power	56.1	52.7	49.9
Depreciation and amortization	97.4	79.9	63.8
	2,978.0	1,047.5	244.5
Operating income	194.3	138.0	97.8
Interest expense	(85.0)	(59.2)	(59.3)
Other income (expense)	2.4	(0.2)	0.9
Minority interest	—	(0.5)	(0.5)
Net income	$ 111.7	$ 78.1	$ 38.9
Net income allocable to common and i-units	$ 92.1	$ 65.0	$ 29.8
Net income per common and i-unit (Note 4)	$ 1.93	$ 1.76	$ 0.98
Weighted average units outstanding	47.7	36.7	30.2
Cash distributions paid per unit	$ 3.70	$ 3.60	$ 3.50

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,		
	2003	2002	2001
	(dollars in millions)		
Net income	$111.7	$ 78.1	$38.9
Unrealized (loss) gain on derivative financial instruments	(47.7)	(28.2)	11.9
Comprehensive income	$ 64.0	$ 49.9	$50.8

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,		
	2003	2002	2001
	(dollars in millions)		
Cash provided from operating activities			
Net income	$ 111.7	$ 78.1	$ 38.9
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	97.4	79.9	63.8
Other	(0.4)	(2.9)	0.3
Changes in operating assets and liabilities, net of acquired working capital:			
Receivables, trade and other	(21.0)	46.0	(22.7)
Due from General Partner and affiliates	(7.2)	—	—
Accrued gas receivables	(59.2)	(162.0)	—
Other current assets	(24.8)	18.7	(9.4)
Due to General Partner and affiliates	(8.7)	12.5	—
Accounts payable and other	(34.1)	(3.6)	54.3
Accrued gas purchases	76.6	136.4	—
Interest payable	(0.2)	(1.2)	0.3
Property and other taxes payable	2.0	(1.3)	(0.2)
Net cash provided by operating activities	$ 132.1	$ 200.6	$ 125.3
Cash used in investing activities			
Additions to property, plant and equipment	(129.3)	(214.7)	(35.0)
Change in construction payable	(7.5)	6.7	(2.1)
Asset acquisitions, net of cash acquired (Note 3)	(294.2)	(349.2)	(265.0)
Net cash used in investing activities	$ (431.0)	$ (557.2)	$(302.1)
Cash provided by financing activities			
Proceeds from unit issuances, net (Note 10)	414.4	424.1	171.3
Distributions to partners	(156.7)	(138.1)	(113.8)
Borrowings under debt agreements	2,653.3	2,939.0	452.0
Repayments of debt	(2,297.0)	(2,643.0)	(505.0)
Borrowings from General Partner and affiliates	16.0	1,074.7	176.2
Repayments to the General Partner and affiliates	(327.0)	(1,279.1)	—
Other	—	(0.9)	(0.9)
Net cash provided by financing activities	$ 303.0	$ 376.7	$ 179.8
Net increase in cash and cash equivalents	4.1	20.1	3.0
Cash and cash equivalents at beginning of year	60.3	40.2	37.2
Cash and cash equivalents at end of year	$ 64.4	$ 60.3	$ 40.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2003	December 31, 2002
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 64.4	$ 60.3
Receivables, trade and other, net of allowance for doubtful accounts of $2.9 in 2003 and $3.7 in 2002	46.3	27.4
Due from General Partner and affiliates	7.2	—
Accrued gas receivables	249.7	190.5
Other current assets	41.2	19.3
	408.8	297.5
Property, plant and equipment, net (Note 5)	2,465.6	2,253.3
Other assets	22.9	12.6
Goodwill (Note 6)	257.3	241.1
Intangibles, net (Note 7)	77.2	30.4
	$3,231.8	$2,834.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 1.8	$ 63.1
Accounts payable and other	85.1	87.2
Accrued gas purchases	230.6	154.0
Interest payable	6.8	7.0
Property and other taxes payable	18.3	16.3
Current maturities and short-term debt (Note 8)	246.0	31.0
	588.6	358.6
Long-term debt (Note 8)	1,155.8	1,011.4
Loans from General Partner and affiliates (Note 10)	133.1	444.1
Commitments, contingencies and environmental liabilities (Note 11)	7.9	5.6
Deferred credits	33.1	23.2
Minority interest	—	0.4
	1,918.5	1,843.3
Partners' capital (Note 9)		
Class A common units (Units issued — 40,166,134 in 2003 and 31,313,634 in 2002)	914.9	604.8
Class B common units (Units issued — 3,912,750 in 2003 and 2002)	64.2	48.7
i-units (Units issued — 10,062,170 in 2003 and 9,228,655 in 2002)	370.7	335.6
General Partner	27.5	18.8
Accumulated other comprehensive loss	(64.0)	(16.3)
	1,313.3	991.6
	$3,231.8	$2,834.9

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

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

	Years ended December 31,					
	2003		2002		2001	
	Units	Amount	Units	Amount	Units	Amount
			(dollars in millions)			
Class A common units:						
Beginning balance	31,313,634	$ 604.8	29,053,634	$ 577.0	24,990,000	$488.6
Net income allocation	—	64.9	—	52.3	—	24.4
Allocation of proceeds and issuance costs from unit issuance	8,852,500	368.2	2,260,000	86.2	4,063,634	154.6
Distributions to partners	—	(123.0)	—	(110.7)	—	(90.6)
Ending balance	40,166,134	914.9	31,313,634	604.8	29,053,634	577.0
Class B common units:						
Beginning balance	3,912,750	48.7	3,912,750	48.8	3,912,750	42.1
Net income allocation	—	8.3	—	7.9	—	5.4
Allocation of proceeds and issuance costs from unit issuance	—	21.7	—	6.1	—	15.0
Distributions to partner	—	(14.5)	—	(14.1)	—	(13.7)
Ending balance	3,912,750	64.2	3,912,750	48.7	3,912,750	48.8
i-units:						
Beginning balance	9,228,655	335.6	—	—	—	—
Net income allocation	—	18.9	—	4.8	—	—
Allocation of proceeds and issuance costs from unit issuance	—	16.2	9,000,001	330.8	—	—
Distributions to partner	833,515	—	228,654	—	—	—
Ending balance	10,062,170	370.7	9,228,655	335.6	—	—
General Partner:						
Beginning balance		18.8		6.5		5.2
Net income allocation		19.6		13.1		9.1
Allocation of proceeds and issuance costs from unit issuance		(0.3)		1.0		1.7
General Partner contribution		8.6		11.5		—
Distributions to partner		(19.2)		(13.3)		(9.5)
Ending balance		27.5		18.8		6.5
Accumulated other comprehensive (loss) income:						
Beginning balance		(16.3)		11.9		—
Unrealized (loss) gain on derivative financial instruments		(47.7)		(28.2)		11.9
Ending balance		(64.0)		(16.3)		11.9
Partners' capital at December 31,		$1,313.3		$ 991.6		$644.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

General

Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation assets, as well as natural gas gathering, treating, processing, transmission 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").

On December 31, 2003, the Partnership acquired the natural gas gathering and processing assets in north Texas (the "North Texas system"). On October 17, 2002, the Partnership acquired the natural gas gathering, treating, processing, transmission and marketing assets of Enbridge Midcoast Energy, Inc. (comprised of the "Midcoast system", "Northeast Texas system" and the "South Texas system") from the General Partner. During 2001, the Partnership acquired the crude oil and liquid petroleum transportation assets of Enbridge Pipelines (North Dakota) L.L.C. (the "North Dakota system") and natural gas gathering, transportation, processing and marketing assets in east Texas (the "East Texas system"). The assets acquired are held in a series of limited liability companies and limited partnerships owned, directly or indirectly, wholly-owned by the Partnership.

On October 17, 2002, in connection with the acquisition described above, the Partnership's ownership of the Lakehead Partnership was restructured such that the Lakehead Partnership is now a wholly-owned subsidiary of the Partnership. As a result of this restructuring, the General Partner holds a 2% general partner interest in the Partnership, but no longer holds a direct interest in the Lakehead Partnership.

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C. and its subsidiary ("Enbridge Management"), a Delaware limited liability company, was formed on May 14, 2002. The General Partner owns all of the voting shares of Enbridge Management. At December 31, 2003 and 2002, Enbridge Management owned approximately 18.2% and 20.3%, respectively, of the outstanding limited partner units of the Partnership. Enbridge Management receives its earnings from this investment.

All of the Partnership's i-units are held by Enbridge Management. As of December 31, 2003 and 2002, Enbridge Management held 10,062,170 and 9,228,655 i-units, respectively. 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, 2003 and 2002, Enbridge and its consolidated subsidiaries owned, through the General Partner, an approximate 12.2% and 14.1% interest, respectively, in the Partnership.

Business Segments

The Partnership conducts its business through four business segments: Liquids Transportation, Gathering and Processing, Natural Gas Transportation, and Marketing. These operating segments are strategic business units established by senior management to facilitate the achievement of the Partnership's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

As a result of the purchase of natural gas assets in October 2002, the Partnership changed the organization of its business segments effective in the fourth quarter of 2002. Prior period segment results have been restated to conform to the Partnership's current organization. For more information on the Partnership's reportable business segments, see Note 14.

Liquids Transportation

Liquids Transportation includes the operations of the Lakehead system, which consists of crude oil and liquid petroleum transportation and storage assets in the Great Lakes and Midwest regions of the United States. The Lakehead system, which spans approximately 1,900 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. Liquids Transportation also includes the operations of the North Dakota system, which consists of crude oil gathering lines connected to a transportation line that interconnects directly with the Lakehead system in the state of Minnesota.

Gathering and Processing

The Gathering and Processing segment includes the East Texas, Midcoast, Northeast Texas, South Texas and the newly acquired North Texas systems. The East Texas system includes natural gas gathering and transmission pipelines, four natural gas treating plants and three natural gas processing plants. The Midcoast system consists of 35 gathering and processing/treating systems, as well as trucks, trailers, and rail cars used for transporting natural gas liquids ("NGLs"), crude oil and carbon dioxide. The Northeast Texas system includes natural gas gathering pipelines, nine natural gas treating plants and three natural gas processing plants. The South Texas system includes natural gas gathering pipelines, a hydrogen sulfide treating plant and a natural gas processing plant. The North Texas system includes natural gas gathering pipelines and nine natural gas processing plants.

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS—(Continued)

Natural Gas Transportation

The Natural Gas Transportation segment consists of four Federal Energy Regulatory Commission ("FERC") regulated natural gas transmission pipeline systems and 35 intrastate natural gas transmission and wholesale customer pipeline systems located in the Mid-Continent and Gulf Coast regions of the United States. These pipeline systems form part of the Midcoast System assets that were acquired from the General Partner in 2002, see Note 3.

Marketing

The Marketing segment primarily provides natural gas supply, transmission storage and sales services for producers and wholesale customers on the Partnership's pipelines as well as other interconnected natural gas 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.

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. 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 evaluates these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the 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 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

The Partnership's Liquids Transportation, Gathering and Processing and certain of its Natural Gas Transportation 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 Transportation 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 accounting principles generally accepted in the United States of America. The Partnership acquired four interstate FERC-regulated natural gas transmission pipeline systems as part of the Midcoast Acquisition, see also Note 3.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

Revenue Recognition

Revenues of the Liquids Transportation segment are derived from interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC. 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 service on the respective pipeline systems. Revenues are recorded upon delivery. The Partnership does not own the crude oil and liquid petroleum that it transports, and therefore does not assume the related commodity risk.

Revenues of the Gathering and Processing segment are derived from gathering and processing services under the following types of arrangements:

Fee-Based Arrangements: Under a fee-based contract, the Partnership receives 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.

Other Arrangements: The Partnership also utilizes other types of arrangements in its natural gas gathering and processing business:

- Percentage-of-Index-Contracts—Under these contracts, the Partnership purchases raw natural gas at a negotiated discount to an agreed upon index. 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 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 is substantially mitigated by offsetting physical purchases and sales and derivative financial instruments. Revenues under all arrangements are recognized upon delivery of natural gas and natural gas liquids to customers and/or upon services rendered.

Revenues of the Natural Gas Transportation segment are generally derived from 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

Revenues of the Marketing segment are derived from providing supply, transmission storage and sales service for producers and wholesale customers on the Partnership's natural gas gathering, transmission and customer 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 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 the request of some customers, the Partnership will enter into long-term fixed price purchase or sale 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 natural gas liquids to customers and/or upon services 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 $11.9 million and $2.9 million at December 31, 2003 and 2002, 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.

Other Current Assets

Other current assets include product inventory, materials and supplies inventory, and prepaid expenses. The product inventory consists of natural gas liquids and natural gas. All inventories are valued at the lower of cost or market.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

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 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 estimated useful lives. For all segments, on 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.

Capital expenditures are categorized by the Partnership 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 the Partnership to respond to governmental regulations and developing industry standards.

The Partnership evaluates impairment of long-lived assets 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 will 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 estimating the fair value using a discounted cash flow approach. There have been no impairments recorded in 2003, 2002 or 2001.

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 three of the Partnership's segments, Gathering and Processing, Natural Gas Transportation, and Marketing.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

Effective January 1, 2002, the Partnership adopted SFAS No. 142, "*Goodwill and Other Intangible Assets*". Goodwill is not amortized but is tested for impairment annually, or more frequently if impairment indicators arise that indicate the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds the fair value of the reporting unit. At the time the Partnership determines that impairment has occurred, the carrying value of the goodwill is written down to its fair value.

Intangibles, Net

Other intangible assets consist of natural gas purchase and sale customer contracts, and natural gas opportunities, which are amortized on a straight-line basis, which approximates the effective interest method, over the weighted average useful life of the underlying reserves.

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 2003, 2002, or 2001.

Other Assets

Other assets primarily include deferred financing charges, which are amortized on a straight-line basis, which approximates the effective interest method, 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 fractionation margins. In order to manage the risks to Partnership unitholders, the General Partner uses 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. 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 Statement of Income.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

In implementing its hedging programs, the General Partner 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 cashflow(s) related to a forecasted transaction. Fair value hedges are entered into to hedge the value of a recognized asset or liability.

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 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 mark to market 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 there should not be a net earnings effect.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

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 at least 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 asset 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 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 cost of removal in its regulated cost of service rates charged to customers. For the year ended December 31, 2003, the Partnership recorded a $0.8 million long-term liability with a resulting increase in the related property, plant and equipment in the consolidated statement of financial position and a corresponding accretion expense of $0.1 million in the consolidated statement of net income.

Comparative Amounts

Certain reclassifications have been made to the prior years' reported amounts to conform to the classifications used in the 2003 consolidated financial statements. These reclassifications have no impact on net income.

New Accounting Pronouncements

In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities*." This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. In particular, this statement: (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative discussed in paragraph 6(b) of SFAS No. 133, (2) clarifies when a derivative contains a financing component, (3) amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, and (4) amends certain other existing pronouncements. The new standard was adopted July 1, 2003 and did not have a significant impact on the Partnership's financial position, results of operations, or cash flows.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

In January 2003, the FASB issued Interpretation No. 46, "*Consolidation of Variable Interest Entities*" ("FIN 46"). FIN 46 requires an investor with a majority of the variable interests in a variable interest entity to consolidate the entity and also requires majority and significant variable interest investors to provide certain disclosures. A variable interest entity is an entity in which the equity investors do not have a controlling interest or the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support form the other parties. In December 2003, the FASB completed deliberations of proposed modifications to FIN 46 resulting in multiple effective dates based on the nature as well as the creation date of the variable interest entity. However, the revised Interpretation must be applied no later than the first quarter of fiscal year 2004. There was no impact on the Partnership's consolidated financial position or results if operations as a result of the adoption of FIN 46, as revised.

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 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 determined by independent appraisals. The results of operations from these acquisitions are included in earnings from the effective date of acquisition.

North Texas Acquisition

Effective 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 $249.7 million, which includes the buyout of a capital lease of $1.9 million and transaction costs of $1.8 million. The purchase was funded with borrowings under the Partnership's 364-day revolving credit facility and three-year term facility. The value allocated to the assets was determined by an independent appraisal. Goodwill associated with the acquisition was $23.9 million, and is allocated entirely to the Gathering and Processing segment. Intangible assets acquired of $48.1 million represents 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 systems and is recorded in the Gathering and Processing segment. Of the $2.7 million environmental liabilities assumed, $0.5 million are included in accounts payable and other and $2.2 million are included in commitments, contingencies and environmental liabilities on the consolidated Statement of Financial Position.

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	$249.7
Allocation of purchase price:	
Current assets	$ 0.4
Property, plant and equipment, including construction in progress	181.0
Intangibles	48.1
Goodwill	23.9
Current liabilities	(1.0)
Environmental liabilities	(2.7)
Total	$249.7

Midcoast Acquisition

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. The following assets were purchased:

Midcoast System

This system includes 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, including:

- four interstate FERC-regulated natural gas transmission pipeline systems;
- intrastate natural gas transmission and wholesale customer pipeline systems;
- gathering and processing/treating systems, including four processing plants; and
- trucks, trailers and rail cars used for transporting natural gas liquids, crude oil and carbon dioxide.

Northeast Texas System

This system includes natural gas gathering pipelines, four active natural gas treating plants, and two active natural gas processing plants. This system is located adjacent to the Partnership's East Texas system.

South Texas System

This system includes natural gas gathering pipelines, a hydrogen sulfide treating plant and an inactive natural gas processing plant.

3. ACQUISITIONS—(Continued)

The Partnership funded this acquisition through the assumption of $472.3 million in debt related to the acquired systems, the issuance to the General Partner of an additional $8.2 million equity interest in the Partnership, $332.7 million of proceeds from the issuance of i-units to Enbridge Management and the payment to the General Partner of $11.7 million in cash, which was funded by the Partnership with borrowings under its 364-day revolving credit facility. A committee of independent members of the Board of Directors of the General Partner negotiated the purchase price and the terms of the acquisition on behalf of the Partnership and recommended that the Board of Directors of the General Partner approve the acquisition on behalf of the Partnership. The value allocated to the assets was determined by agreement between the parties and supported by an independent appraisal. Included in the acquired current assets of $51.3 million is a $3.7 million reserve for doubtful accounts. Goodwill associated with the acquisition was $226.0 million, and is allocated to the Gathering and Processing, Natural Gas Transportation, and Marketing segments. Intangible assets acquired of $16.1 million relate to customer contracts for gas purchases and sales and are recorded in the Gathering and Processing and Natural Gas Transportation segments. Other liabilities consist primarily of amounts payable for gas, NGL and interest rate swaps of $14.6 million and an environmental contingency of $5.9 million.

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

	(dollars in millions)
Purchase Price:	
Debt assumed	$472.3
Issuance of equity interest to the General Partner	8.2
Cash paid, including transaction costs	344.4
Working capital and other adjustments(1)	50.6
Total purchase price	$875.5
Allocation of purchase price:	
Current assets	$ 51.3
Property, plant and equipment	626.7
Goodwill(1)	226.0
Other assets and intangibles	19.1
Current liabilities	(26.4)
Other liabilities	(21.2)
Total	$875.5

(1) Working capital and other adjustments were settled and paid in December 2003 for $43.8 million, which includes $2.0 million of interest. As a result, Goodwill was reduced by $8.8 million.

Pro Forma Information (Unaudited)

The following summarized unaudited Pro Forma Consolidated Income Statement information for the twelve months ended December 31, 2003 and 2002 assumes the acquisitions described above occurred as of January 1, 2002. 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,

3. ACQUISITIONS—(Continued)

2002 or the results that will be attained in the future. Amounts presented below are in millions, except for the per unit amounts.

	Pro Forma Year Ended December 31,	
	2003	2002
	(Unaudited)	
Revenues	$3,484.4	$2,209.1
Net Income	$ 127.4	$ 70.7
Net Income per Unit	$ 2.11	$ 1.16

4. NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deduction of the General Partner's allocation, by the weighted average number of Class A and B common units and i-units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. Net income per unit was determined as follows:

	Year ended December 31,		
	2003	2002	2001
	(dollars and units in millions, except per unit amounts)		
Net income	$111.7	$ 78.1	$38.9
Net income allocated to General Partner	(2.2)	(1.1)	(0.4)
Incentive distributions and historical cost depreciation adjustments	(17.4)	(12.0)	(8.7)
	(19.6)	(13.1)	(9.1)
Net income allocable to common units and i-units	$ 92.1	$ 65.0	$29.8
Weighted average outstanding	47.7	36.7	30.2
Net income per common and i-unit	$ 1.93	$ 1.76	$0.98

5. PROPERTY, PLANT AND EQUIPMENT

	Depreciation Rates	December 31, 2003	December 31, 2002
		(dollars in millions)	
Land	—	$ 12.6	$ 10.4
Rights-of-way	0.60% — 5.71%	222.9	192.5
Pipeline	0.60% — 14.29%	1,770.1	1,576.1
Pumping equipment, buildings and tanks	0.20% — 20.00%	587.9	520.1
Compressors, meters, and other operating equipment	1.52% — 20.00%	167.3	114.5
Vehicles, office furniture and equipment	0.09% — 33.33%	69.4	62.1
Processing and treater plants	4.00%	115.2	96.4
Construction in progress	—	66.8	130.1
		$3,012.2	$2,702.2
Accumulated depreciation		(546.6)	(448.9)
		$2,465.6	$2,253.3

Based on a third-party study commissioned by management, revised depreciation rates for the Lakehead system were implemented effective January 1, 2003, which represent the expected remaining service life of the pipeline system. The annual composite rate was reduced from 3.9% to 3.17% on the Lakehead System. Depreciation expense would have been approximately $109.6 million or $13.4 million higher and net income per unit would have been approximately $1.65 or $0.28 cents lower had the 2002 depreciation rates been in effect during 2003.

6. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2003 and 2002 are as follows:

	Liquids Transportation	Gathering and Processing	Natural Gas Transportation	Marketing	Corporate	Total
			(dollars in millions)			
Balance as of January 1, 2002	$—	$ 15.1	$ —	$ —	$—	$ 15.1
Acquired during the year in conjunction with the Midcoast acquisition	—	132.1	73.5	20.4	—	226.0
Balance as of December 31, 2002	$—	$147.2	$73.5	$20.4	$—	$241.1
Purchase price adjustments	—	0.8	(8.5)	—	—	(7.7)
Acquired during the year in conjunction with the North Texas acquisition	—	23.9	—	—	—	23.9
Balance as of December 31, 2003	$—	$171.9	$65.0	$20.4	$—	$257.3

Net income and earnings per unit, as reported for the year ending December 31, 2001, would have been unaffected by our adoption of SFAS No. 142 as the balance of goodwill at January 1, 2002 was acquired on November 30, 2001 and did not result in the recognition of material amortization expense for the year ending December 31, 2001.

6. GOODWILL—(Continued)

In accordance with SFAS No. 142, the Partnership completed its annual goodwill impairment test as of June 30, 2003. 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 the total equity of each reporting unit was determined to exceed the respective carrying value. As a result, no goodwill impairment existed in any of its reporting units at June 30, 2003 and no events 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, 2003.

7. INTANGIBLES

	December 31,			
	2003		2002	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(dollars in millions)			
Customer Contracts	$31.1	$(2.0)	$31.1	$(0.7)
Natural gas supply opportunities	48.1	—	—	—
	$79.2	$(2.0)	$31.1	$(0.7)

Customer contracts are comprised entirely of natural gas purchase and sale contracts and are recorded in the Gathering and Processing, Natural Gas Transportation, and Marketing segments. Customer contracts are amortized 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 Gathering and Processing segment. The value of the intangible 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, 2003, 2002 and 2001, were $1.3 million, $0.7 million, and zero, respectively.

The estimated amortization expense for each of the years ended December 31, 2004, 2005, 2006, 2007, and 2008 is $3.1 million, respectively.

8. DEBT

	Weighted Average Interest Rate	Maturity	December 31, 2003	December 31, 2002
			(dollars in millions)	
First Mortgage Notes	9.15%	2011	$ 248.0	$ 279.0
Senior Unsecured Notes	6.20%	2012-2033	698.8	299.4
Three-year Term Facility	1.84%	2006	240.0	252.0
364-Day Credit Facility	1.90%	2004	215.0	212.0
			$1,401.8	$1,042.4
Current maturities and short-term debt			(246.0)	(31.0)
Long-term debt			$1,155.8	$1,011.4

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. 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 issuance tests 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 9) 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.

Senior Unsecured Notes

On May 27, 2003, the Partnership issued $200.0 million in aggregate principal amount of its 4.75% Notes due 2013 and $200.0 million in aggregate principal amount of its 5.95% Notes due 2033 (the "Notes") in a private placement. The Partnership used the proceeds of approximately $396.3 million, net of expenses of approximately $3.0 million, to repay loans from affiliates of the Partnership and other bank debt. The Partnership recorded a discount of $0.7 million in connection with the issuance of the Notes. On June 30, 2003, the Partnership completed a Form S-4 with the Securities and Exchange Commission (the "SEC"), which registered the exchange of the unregistered Notes for publicly registered Notes.

8. DEBT—(Continued)

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

Senior Unsecured Notes	Interest Rate	December 31, 2003	December 31, 2002
Notes maturing in 2012	7.90%	$100.0	$100.0
Notes maturing in 2013	4.75%	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	—
		$700.0	$300.0
Unamortized Discount		(1.2)	(0.6)
		$698.8	$299.4

Bank Credit Facilities

On January 24, 2003, the Partnership amended and restated the terms of its two unsecured revolving credit facilities, which were originally entered into in January 2002. The facilities consist of a $300.0 million three-year term facility (the "Three-year Facility"), which matures in 2006 (subject to extension as provided in the facility) and a $300.0 million 364-day facility (the "364-day Facility"), which matures in April 2004 (subject to a one-year term out option and extension as provided in the facility). Interest is charged on amounts drawn under each of these facilities at a variable rate equal to the Base Rate or a Eurodollar rate as defined in the facility agreements. In the case of a 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 each facility whether or not drawn. The facility fee varies depending on the Partnership's credit rating. As of December 31, 2003, the facility fees on the three-year and 364-day facilities were 0.20% and 0.15%, respectively. These credit facilities contain restrictive covenants that require that the Partnership maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 4.75 times each as defined in the facility agreements. The facilities agreements also place 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.

Interest

In 2003, 2002, and 2001, interest expense is net of amounts capitalized of $2.2 million, $7.9 million, and $0.3 million, respectively. In 2003, 2002, and 2001, total interest paid was $85.2 million, $59.2 million, and $57.0 million, respectively.

Debt Service Reserve

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 immediate following quarter and an amount

8. DEBT—(Continued)

for First Mortgage Note sinking fund repayments. At December 31, 2003 and 2002, there was no required debt service reserve as all required interest and sinking fund payments had been made.

Maturities of Debt

The scheduled maturities of outstanding debt, excluding market value of interest rate swaps, at December 31, 2003, are summarized as follows:

	(dollars in millions)
2004	$ 246.0
2005	31.0
2006	271.0
2007	31.0
2008	31.0
Thereafter	791.8
Total	$1,401.8

9. PARTNERS' CAPITAL

The Partnership's ownership is comprised of a 2% general partner interest and 98% of 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 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 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.

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.

9. PARTNERS' CAPITAL—(Continued)

In March 2002, the Partnership issued 2.26 million Class A common units at $42.75 per unit, which generated proceeds, net of underwriters' discounts and commissions and issuance expenses, of approximately $93.3 million. Proceeds from this offering were used to repay indebtedness.

Class B common units

At December 31, 2003 and 2002, 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

In October 2002, the Partnership received net proceeds of approximately $330.8 million from Enbridge Management for the issuance of 9,000,000 i-units. The Partnership used the net proceeds to repay debt owed to affiliates that was assumed in connection with the acquisition of the Midcoast system assets.

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'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 the i-units will at all times be equal.

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.

In October 2002, the General Partner received an allocation of the proceeds from i-unit issuance of approximately $8.2 million. In conjunction with the restructuring of the Partnership's subsidiaries immediately following the acquisition of the Midcoast system, the Partnership contributed its 1.0101%

9. PARTNERS' CAPITAL—(Continued)

interest in the Lakehead Partnership to the Partnership at its carrying value of approximately $3.3 million.

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 within 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 business. Further, the Partnership retains an additional amount equal to 2% of the i-unit distribution from the General Partner in respect of the 2% general partner interest in the i-units. 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

9. PARTNERS' CAPITAL—(Continued)

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.

The following table sets forth the distributions, as approved by the Board of Directors for each period in the years ended December 31, 2003, 2002 and 2001.

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	Retained from General Partner(1)	Distribution of Cash
				(dollars in millions, except per unit amounts)			
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	$ 44.1	$ 8.1	$0.2	$ 35.8
July 22, 2002	August 14, 2002	August 5, 2002	0.90	34.6	—	—	34.6
April 25, 2002	May 15, 2002	May 3, 2002	0.90	34.5	—	—	34.5
January 24, 2002	February 14, 2002	February 5, 2002	0.90	32.4	—	—	32.4
				$145.6	$ 8.1	$0.2	$137.3
2001							
October 25, 2001	November 14, 2001	October 31, 2001	$0.875	$ 29.3	$ —	$ —	$ 29.3
July 19, 2001	August 15, 2001	July 31, 2001	0.875	29.3	—	—	29.3
April 19, 2001	May 15, 2001	April 30, 2001	0.875	27.6	—	—	27.6
January 25, 2001	February 14, 2001	December 29, 2000	0.875	27.6	—	—	27.6
				$113.8	$ —	$ —	$113.8

(1) 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.

10. 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 Transportation segment are provided by Enbridge Pipelines Inc., a subsidiary of Enbridge, as 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

10. RELATED PARTY TRANSACTIONS—(Continued)

activities. The costs to provide these services are allocated to the Partnership from Enbridge Pipelines Inc., 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 Transportation assets from another affiliate of Enbridge.

Enbridge also allocates management and administrative costs to the Partnership pursuant to the Partnership's amended and restated limited partnership agreement ("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 2003, 2002 and 2001, the Partnership incurred the following costs related to these services, which are included in operating and administrative expenses.

	Year ended December 31,		
	2003	2002	2001
	(dollars in millions)		
Direct operating and administrative costs	$75.4	$51.2	$22.2
Liquids Transportation/Natural Gas Transportation operating costs	9.6	6.5	8.6
Allocated management and administrative costs, including insurance	14.2	13.5	8.1
	$99.2	$71.2	$38.9

Natural Gas Sales and Purchases

The Partnership purchases natural gas from third parties, which subsequently generates operating revenues from the sales to Enbridge and its affiliates. These transactions are entered into at the market price at the date of sale. Included in the results for the twelve months ending December 31, 2003 and 2002, are operating revenues of $30.6 million and $4.6 million, respectively, related to these sales. There were no such comparative amounts in 2001.

The Partnership also purchases natural gas from Enbridge and its affiliates for sale to third parties at market prices at the date of purchase. Included in the results for the twelve months ending December 31, 2003 and 2002, are cost of natural gas expenses of $1.2 million and $0.1 million, respectively, relating to these purchases. There were no such comparative amounts in 2001.

Affiliate Notes

The Partnership has various notes payable with affiliates of Enbridge that totaled $133.1 million and $444.1 million at December 31, 2003 and 2002. All loans mature in 2007. The weighted average interest rate is 6.60% and 6.03% as of December 31, 2003 and 2002.

Interest expense related to affiliate notes totaled $16.1 million, $4.6 million, and $1.3 million in 2003, 2002, and 2001, respectively. Interest payable to affiliates totaled $2.2 million and $1.3 million at December 31, 2003 and 2002, respectively. Interest paid to affiliates totaled $15.2 million, $3.3 million, and $1.3 million in 2003, 2002 and 2001, respectively.

Incentive Income and Partnership Distributions

Enbridge Energy Company, Inc., an affiliate of Enbridge, serves as the Partnership's general partner. Pursuant to the Partnership's partnership agreement, the General Partner owns an effective 2% ownership interest in the Partnership. The General Partner received incentive distributions for the years ended December 31, 2003, 2002 and 2001 of $17.2 million, $11.9 million, and $8.6 million, respectively.

10. RELATED PARTY TRANSACTIONS—(Continued)

As of December 31, 2003, the General Partner also owned 3,912,750 Class B common units, representing 7.1% ownership in the Partnership. The General Partner received cash distributions related to its ownership of Class B units for the years ended December 31, 2003, 2002 and 2001 of $14.5 million, $14.1 million and $13.7 million, respectively. See also Note 9 (Partners' Capital).

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.

11. COMMITMENTS AND CONTINGENCIES

Environmental

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 prior to the transfer to the Partnership in 1991, 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.

11. COMMITMENTS AND CONTINGENCIES—(Continued)

In connection with the Partnership's acquisition of Midcoast, Northeast Texas and South Texas systems, 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, 2003 and 2002, the Partnership has recorded $2.6 million and $1.1 million in current liabilities and $7.9 million and $5.6 million, respectively, in long-term liabilities to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of its Liquids Transportation and Gathering and Processing assets.

Oil and Gas in Custody

The Partnership's Liquids Transportation assets transport crude oil and NGLs owned by its customers for a fee. The volume of liquid hydrocarbons in the Partnership's pipeline system at any one time approximates 14 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 NGLs in the Partnership's custody.

Approximately 60% of the natural gas volumes on the Gathering and Processing and Natural Gas Transportation assets are transported for customers on their contract, with the remaining 40% 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 Transportation systems is not material to the Partnership.

Regulatory

From 1998, when the Kansas Pipeline system ("KPC") became subject to the FERC jurisdiction, until November 9, 2002, at which time KPC's rate case became effective, the FERC established initial rates based upon an annual cost of service of approximately $31.0 million. Since that time, these initial rates have been the subject of various ongoing challenges that remain unresolved.

The United States Court of Appeals for the D.C. Circuit issued an order on August 12, 2003 vacating the FERC's 2001 remand order and 2002 rehearing order and remanded the issue of KPC's initial rates back to the FERC with directions that the FERC address the question of an appropriate rate refund. In prior KPC orders in this proceeding, the FERC determined that it had no authority to impose a refund condition on initial rates. On October 3, 2003, KPC filed a pleading at FERC requesting the issuance of an order finding that it had no refund obligation and requesting termination of the proceedings on remand. The Missouri Public Service Commission filed an answer to KPC's pleading on October 20, 2003. The outcome of KPC's motion or any other proceedings, including the amount of any refunds that may be ordered, is uncertain. If the FERC determines refunds are required, after all administrative options and court appeals are exhausted, the amount of the refunds affecting the Partnership's earnings may range from zero to $9.0 million.

11. COMMITMENTS AND CONTINGENCIES—(Continued)

Commitments

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 (Note 5). 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 $1.4 million, $1.2 million, and $1.0 million during 2003, 2002, and 2001, respectively.

Future Minimum Commitments

As of December 31, 2003, the future minimum commitments having remaining non-cancelable terms in excess of one year are as follows:

Year ended December 31,	Power and other Purchase Commitments	Other Operating Leases	Right of Way(1)	Total
		(dollars in millions)		
2004	$12.9	$ 3.9	$ 1.8	$18.6
2005	3.1	4.2	1.9	9.2
2006	3.1	3.7	1.8	8.6
2007	—	2.7	1.8	4.5
2008	—	2.7	1.7	4.4
Thereafter	—	3.5	45.0	48.5
Total	$19.1	$20.7	$54.0	$93.8

(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 2008.

12. MAJOR CUSTOMERS

At December 31, 2003 and 2002, the Partnership did not have an external customer that accounted for 10% or more of its operating revenues. The customers listed below were all attributable to the Partnership's Liquids Transportation segment. For 2001, operating revenue received from major customers was as follows:

	Year ended December 31, 2001
	(dollars in millions)
BP Canada Energy Company	$73.4
ExxonMobil Canada Energy	$59.7
PDV Midwest	$21.4
Imperial Oil Limited	$24.0

12. MAJOR CUSTOMERS—(Continued)

The Partnership has a concentration of trade receivables from companies operating in the oil and gas industry. These receivables are collateralized by the crude oil and other products contained in the Partnership's pipeline and storage facilities.

13. 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 364-day credit and three-year term facilities approximates fair value.

At December 31, 2003 and 2002, the fair value of the First Mortgage Notes approximates $303.0 million and $334.0 million and the fair value of the Senior Unsecured Notes approximates $739.0 million and $326.0 million, respectively. Due to defined contractual make-whole arrangements, refinancing of the First Mortgage Notes and Senior Unsecured Notes would not result in any financial benefit to the Partnership.

The fair value of derivative financial instruments reflects the Partnership's best estimate and is based upon either exchange- traded prices, published market prices or over-the-counter market price quotations, whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, the Partnership utilizes other valuation 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 (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 (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 2003	Fair Value 2002
		(dollars in millions)				
Fixed rate interest rate swaps:	$100.0	5.95%	LIBOR	October 13, 2003	$ —	$(4.6)
	$ 40.0	4.48%	LIBOR	November 3, 2003	$ —	$(1.2)
	$ 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	$ —	$ —
Floating rate interest rate swaps:	$ 50.0	LIBOR — 21bps	4.75%	June 1, 2013	$1.7	$ —
	$ 50.0	LIBOR — 21bps	4.75%	June 1, 2013	$1.7	$ —
	$ 25.0	LIBOR — 25bps	4.75%	June 1, 2013	$0.8	$ —
Treasury Lock:	$104.0	3.19%	N/A	January 30, 2004	$1.0	$ —

13. FINANCIAL INSTRUMENTS—(Continued)

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 price 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 Gathering and Processing, Natural Gas Transportation and Marketing segments. To mitigate the volatility of cash flows, the exposed entity enters into derivative financial instruments to manage the purchase and sales prices of the commodities. The majority of the Partnership's commodity derivative transactions qualifies 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 at December 31:

System	Maturity Dates	Notional MMBtu	Fair Value 2003	Fair Value 2002
			(dollars in millions)	
East Texas System	2004-2011	26,000	$(19.9)	$ (6.1)
Northeast Texas System	2004-2012	42,000	$(44.9)	$(19.1)
Midcoast System	2004	600	$ (0.7)	$ (0.3)
Marketing	2004-2007	38,000	$ 2.0	$ 2.1

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 (from the last quarter-end) of these derivative instruments is booked to the income statement. For the years ended December 31, 2003 and 2002, $0.3 million and zero, respectively, were recorded in the Consolidated Statements of Income on the cost of natural gas expense to account mark to market changes related to the Marketing segment.

13. FINANCIAL INSTRUMENTS—(Continued)

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 2003	Fair Value 2002
		(in millions)	(dollars in millions)	
Northeast Texas System	2004	0.5	$(2.4)	$(2.5)
Midcoast System	2004	0.1	$(0.2)	$(0.1)
East Texas System	2004	0.5	$(0.8)	$ —
North Texas System	2004	0.8	$(1.1)	$ —

Other

The Partnership estimates that approximately $17.0 million of the Accumulated Other Comprehensive Loss balance on the Consolidated Statement of Financial Position of $64.0 million representing unrecognized net losses on derivative activities at December 31, 2003 is expected to be reclassified into earnings during the next twelve months.

At December 31, 2003, 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, 2003	December 31, 2002
	(dollars in millions)	
Accounts receivable, trade and other	$ 2.8	$ 3.5
Other assets, net	4.0	—
Accounts payable and other	(43.7)	(13.1)
Deferred credits	(27.5)	(22.2)
	$(64.4)	$(31.8)

14. 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 four reportable business segments, Liquids Transportation, Gathering and Processing, Natural Gas Transportation and Marketing (see Note 1). Each segment uses accounting policies as described in the Summary of Significant Accounting Policies (see Note 2).

14. SEGMENT INFORMATION—(Continued)

The following table presents certain financial information relating to the Partnership's business segments as of or for the year ended December 31, 2003 and 2002. As discussed in Note 3 to the Consolidated Financial Statements, the results from the Midcoast Acquisition were included since October 17, 2002.

	As of and for the Year Ended December 31, 2003					
	Liquids Transportation	Gathering and Processing	Natural Gas Transportation	Marketing	(1) Corporate	Total
	(dollars in millions)					
Total Revenues	$ 344.2	$2,153.8	$121.0	$1,984.8	$ —	$4,603.8
Less: Intersegment revenue	—	307.0	3.3	1,121.2	—	1,431.5
Operating revenues	344.2	1,846.8	117.7	863.6	—	3,172.3
Cost of natural gas	—	1,693.3	67.6	851.8	—	2,612.7
Operating and administrative	104.1	81.0	21.3	2.2	3.2	211.8
Power	56.1	—	—	—	—	56.1
Depreciation and amortization	59.5	24.1	13.6	0.2	—	97.4
Operating income	$ 124.5	$ 48.4	$ 15.2	$ 9.4	$ (3.2)	$ 194.3
Interest expense	—	—	—	—	(85.0)	(85.0)
Other income (expense)	—	—	—	—	2.4	2.4
Minority interest	—	—	—	—	—	—
Net income	$ 124.5	$ 48.4	$ 15.2	$ 9.4	$(85.8)	$ 111.7
Total assets	$1,511.2	$1,085.9	$404.6	$ 189.6	$ 40.5	$3,231.8
Capital expenditures (excluding acquisitions)	$ 69.3	$ 51.0	$ 4.4	$ 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.

14. SEGMENT INFORMATION—(Continued)

	As of and for the Year Ended December 31, 2002					
	Liquids Transportation	Gathering and Processing	Natural Gas Transportation	Marketing	(1) Corporate	Total
	(dollars in millions)					
Total Revenues	$ 334.3	$ 780.0	$ 24.8	$ 267.9	$ —	$1,407.0
Less: Intersegment revenue	—	77.8	5.0	138.7	—	221.5
Operating revenues	334.3	702.2	19.8	129.2	—	1,185.5
Cost of natural gas	—	635.2	8.6	126.9	—	770.7
Operating and administrative	104.7	34.5	4.5	0.5	—	144.2
Power	52.7	—	—	—	—	52.7
Depreciation and amortization	64.8	12.3	2.8	—	—	79.9
Operating Income	$ 112.1	$ 20.2	$ 3.9	$ 1.8	$ —	$ 138.0
Interest expense	—	—	—	—	(59.2)	(59.2)
Other income (expense)	—	—	—	—	(0.2)	(0.2)
Minority interest	—	—	—	—	(0.5)	(0.5)
Net income	$ 112.1	$ 20.2	$ 3.9	$ 1.8	$(59.9)	$ 78.1
Total Assets	$1,528.0	$ 734.5	$435.1	$ 137.3	$ —	$2,834.9
Capital Expenditures (excluding acquisitions)	$ 201.8	$ 12.2	$ 0.7	$ —	$ —	$ 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.

	As of and for the Year Ended December 31, 2001					
	Liquids Transportation	Gathering and Processing	Natural Gas Transportation	Marketing	(1) Corporate	Total
	(dollars in millions)					
Total Revenues	$ 313.3	$ 29.0	$ —	$ —	$ —	$ 342.3
Less: Intersegment revenue	—	—	—	—	—	—
Operating revenues	313.3	29.0	—	—	—	342.3
Cost of natural gas	—	26.3	—	—	—	26.3
Operating and administrative	102.7	1.8	—	—	—	104.5
Power	49.9	—	—	—	—	49.9
Depreciation and amortization	63.0	0.8	—	—	—	63.8
Operating Income	$ 97.7	$ 0.1	$ —	$ —	$ —	$ 97.8
Interest expense	—	—	—	—	(59.3)	(59.3)
Other income (expense)	—	—	—	—	0.9	0.9
Minority interest	—	—	—	—	(0.5)	(0.5)
Net income	$ 97.7	$ 0.1	$ —	$ —	$(58.9)	$ 38.9
Total Assets	$1,372.6	$ 276.6	$ —	$ —	$ —	$1,649.2
Capital Expenditures (excluding acquisitions)	$ 34.9	$ 0.1	$ —	$ —	$ —	$ 35.0

(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. SUBSEQUENT EVENTS

Mid-Continent Liquids System Acquisition

On December 22, 2003, the Partnership entered into a definitive agreement to acquire crude oil pipeline and storage for $115.0 million, excluding customary closing adjustments for working capital and other items. The asset purchase closed on March 1, 2004. The assets acquired serve refineries in the Mid-Continent from the Cushing, Oklahoma Hub and consist of some 615 miles of active crude oil pipelines and 9.5 million barrels of storage capacity. Included are:

- The 433 mile Ozark pipeline that currently transports approximately 170,000 barrels of crude oil per day from Cushing to Wood River, Illinois;
- A 1.2 million barrel storage terminal;
- The 47-mile West Tulsa pipeline that currently transports approximately 55,000 barrels per day to two refineries in Oklahoma; and
- The Shell storage terminal at Cushing, which is one of the largest terminal facilities in North America with 8.3 million barrels of storage capacity.

These systems provide cash flows primarily from toll or fee-based revenues from a combination of regulated assets and contracted unregulated. The assets will be included in the Partnership's Liquids Transportation segment.

Class A common unit issuance

On January 2, 2004, the Partnership issued an additional 450,000 Class A common units pursuant to the 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 expenses, of approximately $21.7 million. In addition to the proceeds generated from the unit issuance, the General Partner contributed $0.5 million to the Partnership to maintain its 2% general partner interest in the Partnership.

Distribution Declaration

On January 22, 2004, the Partnership's Board of Directors declared a distribution payable on February 13, 2004, to unitholders of record as of February 2, 2004, of its available cash of $55.8 million at December 31, 2003, or $0.925 per common unit. Of this distribution, $9.3 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.

Senior Unsecured Note Issuance

On January 9, 2004, the Partnership issued an additional $200.0 million in aggregate principal amount of its 4.0% Senior Unsecured Notes due in 2009 in a public offering, from which it resulted in net proceeds of $198.4 million. The Partnership used the proceeds to repay a portion of its outstanding Bank Credit Facilities debt.

16. QUARTERLY FINANCIAL DATA (unaudited)

(Dollars in millions, except per unit amounts)

	First	Second	Third	Fourth	Total
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 unit(1)	$ 0.62	$ 0.39	$ 0.38	$ 0.54	$ 1.93

	First	Second	Third	Fourth	Total
2002 Quarters					
Operating revenue	$181.8	$223.1	$237.7	$542.9	$1,185.5
Operating income	$ 32.5	$ 30.4	$ 31.8	$ 43.3	$ 138.0
Net income	$ 17.7	$ 16.8	$ 17.6	$ 26.0	$ 78.1
Net income per unit(1)	$ 0.43	$ 0.39	$ 0.42	$ 0.52	$ 1.76

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