TC PIPELINES LP
Form 10-K
February 28, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007

or

o **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: 000-26091

TC PipeLines, LP

(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**52-2135448** **(I.R.S. Employer Identification Number)**
13710 FNB Parkway **Omaha, Nebraska** **(Address of principal executive offices)**	**68154-5200** **(Zip code)**

877-290-2772
(Registrant s telephone number, including area code)

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

None

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

Common units representing limited partner interests

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x **No** o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o **No** x

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 x **No** o

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 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.

x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerate filer , accelerated filer and small reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x **Accelerated filer** o **Non-accelerated filer** o **Small Reporting Company** o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes o **No** x

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as at June 29, 2007 was approximately $953.5 million.

As of February 28, 2008, there were 34,856,086 of the registrant s common units outstanding.

TC PIPELINES, LP

TABLE OF CONTENTS

All amounts are stated in United States dollars unless otherwise indicated.

PART I

FORWARD-LOOKING STATEMENTS

The statements in this report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. Forward-looking statements may include words such as anticipate, estimate, expect, project, intend, plan, believe, forecast and other words and terms of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking.

These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors that could cause actual results to differ materially from those contemplated in the forward-looking statements include:

- the ability of Great Lakes and Northern Border to continue to make distributions at their current levels;
- the impact of unsold capacity on Great Lakes and Northern Border being greater or less than expected;
- competitive conditions in our industry and the ability of our pipeline systems to market pipeline capacity on favorable terms, which is affected by:
- future demand for and prices of natural gas;
- competitive conditions in the overall natural gas and electricity markets;
- availability of supplies of Canadian and U.S. natural gas;
- availability of additional storage capacity;
- weather conditions; and
- competitive developments by Canadian and U.S. natural gas transmission companies;
- the Alberta (Canada) government s decision to implement a new royalty regime effective January 2009 may affect the amount of exploration and drilling in the Western Canada Sedimentary Basin;
- performance of contractual obligations by customers of our pipeline systems;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the impact of current and future laws, rulings and governmental regulations, particularly FERC regulations, on us and our pipeline systems;

- our ability to control operating costs; and

- prevailing economic conditions, including conditions of the capital and equity markets and our ability to access these markets.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. Please also read Item 1A. Risk Factors. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. These forward-looking statements and information is made only as of the date of the filing of this report, and except as required by applicable law, we undertake no obligation to update these forward-looking statements and information to reflect new information, subsequent events or otherwise.

Item 1. Business

OVERVIEW

We are a publicly traded Delaware limited partnership formed in 1998 by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to as TransCanada), to acquire, own and participate in the management of United States (U.S.) based pipeline systems. We have broadened our initial scope to energy infrastructure assets in North America. To date, our primary focus has been in the transportation of natural gas from the Western Canada Sedimentary Basin (WCSB) to a variety of downstream markets.

TC PipeLines, LP and its subsidiary limited partnerships and subsidiary limited liability company, including, TC PipeLines Intermediate Limited Partnership (TC PipeLines ILP), TC Tuscarora Intermediate Limited Partnership (TC Tuscarora ILP), TC GL Intermediate Limited Partnership (TC GL ILP) and TC Pipelines Tuscarora LLC (TC Tuscarora LLC), are collectively referred to herein as TC PipeLines or the Partnership. In this report, references to we , us or our collectively refer to TC PipeLines or the Partnership. The general partner of the Partnership is TC PipeLines GP, Inc. (TC PipeLines GP), a wholly-owned subsidiary of TransCanada.

Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile. Our current portfolio of pipeline investments in the U.S. consists of:

- A 100 per cent general partner interest in Tuscarora Gas Transmission Company (Tuscarora).

- A 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). The remaining 53.55 per cent interest in Great Lakes is held by TransCanada.

- A 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border). The other 50 per cent interest is held by ONEOK Partners, L.P. (ONEOK Partners), a publicly traded limited partnership that is controlled by ONEOK, Inc.

We account for our interests in both Great Lakes and Northern Border as equity investments; therefore, we do not consolidate their financial results. TransCanada operates Great Lakes, Northern Border and Tuscarora (collectively, our pipeline systems). See Item 13. Certain

Relationships and Related Transactions, and Director Independence .

Recent Developments

Tuscarora 100 per cent Ownership - On December 31, 2007, we purchased the remaining two per cent interest in Tuscarora, increasing our ownership interest to 100 per cent. One per cent was purchased from a wholly-owned subsidiary of TransCanada, while the other one per cent was purchased from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, for a combined purchase price of $3.9 million.

Northern Border Operatorship - On April 1, 2007, TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became the operator of Northern Border, pursuant to an operating agreement entered into with Northern Border in April 2006.

Great Lakes Acquisition - On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation. The total purchase price was $942.4 million, subject to certain closing adjustments, and included the indirect assumption of approximately $209.0 million of debt. The acquisition was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million which closed concurrently with the acquisition. TransCan Northern Ltd. (TransCan Northern), a wholly-owned subsidiary of TransCanada, purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with this transaction. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the remaining 3.55 per cent interest simultaneously with the Partnership s acquisition of its interest. A wholly-owned subsidiary of TransCanada also became the operator of Great Lakes.

Other Developments

Tuscarora Increased Ownership On December 19, 2006, the Partnership acquired an additional 49 per cent general partnership interest in Tuscarora for approximately $99.8 million. In connection with this transaction, TCNB became the operator of Tuscarora.

Implementation of New Rates, Northern Border In November 2006, the Federal Energy Regulatory Commission (FERC) approved the uncontested settlement of Northern Border s rate case. Beginning January 1, 2007, Northern Border s overall rates were reduced compared with rates prior to the filing, by approximately 5 per cent. The settlement also provided for seasonal rates for short-term transportation service.

Tuscarora Cost and Revenue Study The Public Utilities Commission of Nevada (PUCN) approved Tuscarora s rate adjustment, which was subsequently approved by the FERC on July 3, 2006. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006, or a 17 per cent reduction to the previous rates of $0.481/dth-day.

Northern Border Increased Ownership In April 2006, TC PipeLines purchased a 20 per cent partnership interest in Northern Border from ONEOK Partners. After the transaction, TC PipeLines and ONEOK Partners each own a 50 per cent interest in Northern Border.

Business Strategies

Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

Our business strategies to achieve these objectives are to seek opportunities to undertake accretive acquisitions and organic growth projects, and maximize the value of our existing portfolio of pipeline systems. Working with our partners, if any, in our pipeline systems, we seek to pursue policies that:

- Maximize the utilization of our pipeline systems;
- Expand our pipeline systems to meet market demand; and
- Continue to promote safe and efficient operations.

In addition, we intend to support the execution of our business strategies by:

- Maintaining a strong and balanced financial position to:
- maintain a prudent level of available cash for distribution to unitholders;
- fund future growth; and
- broaden our asset base in a disciplined and focused manner;
- Investing in North American energy infrastructure assets that are underpinned by strong business fundamentals and provide stable cash flows; and
- Maximizing the benefits of our relationship with TransCanada.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- Our pipeline systems hold strategic market positions and comprise critical transportation links for the transportation of natural gas from the Alberta Hub to U.S. markets. The Alberta Hub is one of the largest natural gas hubs in North America. Additional Canadian natural gas supply sources may be available in the future if new pipeline projects associated with the Mackenzie Delta in Northern Canada and Alaska are constructed;

- With TransCanada as operator of our pipeline systems, we believe they are well positioned to continue to operate as trusted and experienced transportation providers to our customers; and

- The senior management team and the board of directors of our general partner have extensive industry experience and include some of the most senior officers of TransCanada. The management team plays a significant role in developing the strategic direction of our pipeline systems and their associated operations, and we believe our ability to execute our business strategies is enhanced by our affiliation with TransCanada.

Our Relationship with TransCanada Corporation

One of our principal strengths is our relationship with TransCanada. TransCanada is a major North American energy infrastructure company with approximately 36,500 miles of wholly-owned natural gas pipelines, interests in an additional 4,800 miles of natural gas pipelines, approximately 360 billion cubic feet (Bcf) of storage capacity and, including facilities that are under construction or in development, also owns, operates, and/or controls approximately 7,700 megawatts of power generation. TransCanada, a Canadian corporation, was founded in 1951 with the objective of transporting natural gas from Alberta to distant markets. Today, TransCanada is engaged in numerous aspects of the energy industry but is primarily focused on natural gas transmission and power generation services.

TransCanada provides access to a significant pool of management talent and strong relationships throughout the energy industry. We expect to pursue strategic acquisitions in a disciplined manner and to have the opportunity to participate jointly with TransCanada in reviewing potential acquisitions, including transactions that we would be unable to pursue on our own. Additionally, we may have the opportunity to make acquisitions directly from TransCanada in the future. TransCanada, however, is under no obligation to allow us to participate in any of its pipeline or energy infrastructure acquisitions, nor is TransCanada required to offer any of its assets to us.

As of December 31, 2007, we had 34,856,086 common units outstanding, of which 24,142,935 were held by the public and 10,713,151 were held by wholly-owned subsidiaries of TransCanada. In addition, TransCanada owns the Partnership s general partner which holds a two per cent general partner interest in the Partnership. As such, TransCanada receives distributions as a common unitholder, distributions related to its two per cent general partner interest, as well as general partner incentive distributions if quarterly cash distributions on the common units exceed levels specified in the partnership agreement. See Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities .

Our Pipeline Systems

All of our pipeline systems are rate regulated by the FERC. Operating revenue is derived from the transportation of natural gas. The maximum transportation rates that our pipeline systems may charge are approved by the FERC, and in most cases, established in a FERC proceeding known as a rate case. During a rate case, a determination is reached by the FERC, either through a hearing or a settlement, on the maximum rates permissible for transportation service that include the recovery of cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set, the pipeline system is not permitted to adjust the maximum rates to reflect changes in costs or contract demand until new rates are approved by the FERC, usually after a rate case has been filed. Each pipeline system s tariff is approved by the FERC and specifies the maximum rates, as well as the general terms and conditions for natural gas transportation service on its pipeline. The tariff also allows for services to be provided under negotiated and discounted rates. As a result, earnings and cash flow of each pipeline system depend on costs incurred; contracted capacity and transportation path; the volume of gas transported; and the ability of each system to sell capacity at acceptable rates.

Our pipeline systems transportation contracts include specifications regarding the receipt and delivery of natural gas at points along the pipeline system. The type of transportation contract, either for firm or interruptible service, determines the basis upon which each customer is charged. Customers with firm service transportation agreements pay a fee known as a reservation charge to reserve pipeline capacity, regardless of use, for the term of their contracts. On the Great Lakes and Northern Border systems, firm service transportation customers also pay a variable usage fee known as a commodity charge or utilization fee that is based on distance and the volume of natural gas they transport. Transportation customers on the Northern Border system also pay a compressor usage surcharge, effective with the settlement of the 2005 rate case, resulting in new rates which were implemented January 1, 2007. Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges (or utilization fees) based on distance and the volume of natural gas they transport. The table below provides information with respect to tariff revenue composition for each of our investments for the year ended December 31, 2007. The weighted average remaining contract life is determined as at January 31, 2008.

		Tariff Revenue Composition			
		Firm Contracts			
	Our Ownership Interest	Capacity Reservation Charges	Variable Usage Fees (1)	Interruptible Contracts & Other Services	Weighted Average Remaining Contract Life (in years) (2)
Great Lakes	46.45%	97%	3%	0%	2.4
Northern Border	50%	91%	7%	2%	1.3
Tuscarora	100%	100%	n/a	0%	10.4

(1) Variable usage fees for Northern Border include a compressor usage surcharge which relate to both, firm and interruptible contracts. Tuscarora does not have any variable usage fees as part of their tariff.

(2) Weighted average remaining contract life is weighted based upon maximum daily quantity (MDQ) in the contracts.

The table below provides information on the average throughput of our pipeline systems:

Average Throughput (MMcf/d)	2007	2006	2005
Great Lakes (1)	2,270	2,236	2,360
Northern Border	2,247	2,246	2,277
Tuscarora	77	77	69

(1) The average throughput for Great Lakes includes periods prior to the February 22, 2007 acquisition by us of a 46.45 per cent general partner interest in Great Lakes.

Business of Great Lakes

Great Lakes is a Delaware limited partnership formed in 1990 and holds the assets formerly held by Great Lakes Transmission Company. The FERC certificate to construct its initial facilities was issued in 1967. Great Lakes is owned 46.45 per cent by us, with the remainder owned by TransCanada. Additionally, Great Lakes is operated by TransCanada.

The major policies of Great Lakes are established by the management committee of Great Lakes (GL Management Committee), which consists of up to six members, three of whom are designated by us and three of whom are designated by TransCanada. The GL Management Committee consists of four appointed members, two of whom are designated by us and two of whom are designated by TransCanada. All decisions by the GL Management Committee require unanimous consent. For the day to day management of Great Lakes business, the GL Management Committee established an executive committee, which consists of up to three members: one Partnership GL Management Committee Member, one TransCanada GL Management Committee Member and the president of Great Lakes, who is a non-voting member (GL Executive Committee). The GL Executive Committee currently consists of two appointed members: one Partnership GL Management Committee member, and one TransCanada GL Management Committee member, who also serves as the president of Great Lakes. The GL Executive Committee has all of the powers of the GL Management Committee in the management of Great Lakes business.

Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba. Great Lakes pipeline system extends across Minnesota, Northern Wisconsin and Michigan, and redelivers gas to TransCanada at the Canadian border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

The Great Lakes mainline transmission pipeline has diameters ranging from 10 inches to 36 inches. The Great Lakes system consists of approximately 2,115 miles of pipeline with a design capacity of 2.3 Bcf per day at the Emerson Inlet. Great

Lakes has 14 compressor stations with a total of 438,000 horsepower and measurement facilities to support the 55 receipt and delivery points for gas.

The original construction of Great Lakes system occurred in 1967 and 1968. There have been numerous capacity system expansions since its original construction, the last one completed in 1998.

Business of Northern Border

Northern Border is a Texas general partnership formed in 1978. TC PipeLines, through its subsidiary TC PipeLines ILP, and ONEOK Partners, through its subsidiary ONEOK Partners Intermediate Limited Partnership, each own a 50 per cent interest in Northern Border.

Northern Border is managed by a management committee that consists of four members. Each partner designates two members, and we designate one of our members as Chairman. Each partner holds a 50 per cent voting interest on the management committee.

Northern Border extends from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Northern Border s transportation system provides pipeline access to the Midwestern U.S. from natural gas reserves in the WCSB. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana and synthetic gas produced at the Dakota Gasification plant in North Dakota.

The pipeline system consists of 1,249 miles of pipeline with diameters ranging from 30 to 42 inches and a design capacity on the largest segment of the pipeline of 2,374 MMcf/d. Along the pipeline are 17 compressor stations with a total of 515,000 horsepower, measurement facilities to support the receipt and delivery of gas at ten receipt and 50 delivery points, four field offices and a microwave communication system with 50 tower sites.

Construction of Northern Border s system was initially completed in 1982, followed by expansions or extensions in 1991, 1992, 1998, 2001 and 2006.

Des Plaines Project In February 2008, Northern Border filed with the FERC to construct, own and operate interconnect facilities, including a 1,600 horsepower compressor facility near Joliet, Illinois. It is estimated that this project will cost approximately $17 million. The targeted in-service date included in Northern Border s FERC certificate application is November 1, 2008; however, this schedule is dependent upon the receipt of timely regulatory approvals. The Des Plaines Project will be fully subscribed under long-term compression and transportation contracts, per the executed precedent agreement.

Business of Tuscarora

Tuscarora is a Nevada general partnership formed in 1993. We own 100 per cent of Tuscarora through two subsidiaries: TC Tuscarora ILP owns a 99 per cent general partner interest in Tuscarora, with TC Pipelines Tuscarora LLC owning the remaining one per cent general partner interest.

The Tuscarora system originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs Southeast through Northeastern California and Northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada.

Tuscarora owns a 240-mile, 20-inch diameter, pipeline system with a design capacity of approximately 190 MMcf/d. Tuscarora has two compressor stations with a total of 11,400 horsepower, and measurement facilities at one receipt point and 16 delivery points.

The Tuscarora pipeline system was initially placed into service in 1995. Expansions or extensions were completed in 2001, 2002 and 2005.

2008 Expansion Project - In July 2007, Tuscarora received FERC approval for the construction of a compressor station and related facilities (Tuscarora 2008 Expansion Project). This approximately $20 million project is underpinned by a 22.5 year long-term contract to transport a maximum of 39 MMcf/d to Sierra Pacific Power Company (Sierra Pacific Power), a subsidiary of Sierra Pacific Resources, to supply its Tracy Combined Cycle Power Plant. The project is expected to be in service in March 2008.

NATURAL GAS INDUSTRY OVERVIEW

North American Demand

Over the last fifteen years, natural gas demand in North America has increased by approximately 15 Bcf/d. Demand for natural gas is expected to continue to grow across North America in 2008 and beyond. Demand for natural gas transportation service on a pipeline system is directly related to demand for natural gas in the markets served by that system. Factors that may impact demand for natural gas include:

- weather conditions;
- economic conditions;
- government regulation;
- the availability and price of alternative energy sources versus natural gas;
- natural gas storage inventories for the markets served;
- fuel conservation measures; and
- technological advances in fuel economy and energy generation devices.

Furthermore, factors that may impact demand for natural gas transportation service on any one system include:

- availability of natural gas supply at the pipeline system s receipt points;
- the ability and willingness of natural gas shippers to utilize the pipeline system over alternative pipelines;
- relative transportation rates; and

- the volume of natural gas delivered to markets from other supply sources and storage facilities.

The primary exposure to business risk for our pipeline systems occurs when our pipeline systems are marketing their available capacity, such as when existing transportation contracts expire and are subject to renegotiation. Customers with competitive alternatives analyze the market price spread or basis differential between receipt and delivery points along the pipeline to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay. The customers on our pipelines include local distribution companies (LDCs), industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies.

Our Pipeline Systems

Demand for transportation on Great Lakes has remained relatively constant over the last five years from LDCs and industrial customers, as well as for transportation of volumes back into Canada. Great Lakes customer profile is becoming more heavily weighted towards natural gas marketing and trading companies and less towards producers and end users, such as industrial customers and LDCs.

Northern Border s contract life has been declining with a customer profile over the past five years mainly comprised of producers and natural gas marketing and trading companies. Northern Border delivers gas to highly competitive markets including interconnections with other major interstate natural gas pipelines and major market centers that serve winter heating and summer cooling demand, industrial load and storage areas to replenish inventory.

Demand on Tuscarora has steadily increased over the last several years due to increased demand from electric generation companies and LDCs.

Seasonality

North America

North American demand for natural gas is seasonal. In general, demand tends to be higher in the winter months for heating requirements and in the summer for power generation demand in support of cooling requirements. This effect can be somewhat mitigated in the spring and fall by the need for industries to replenish the amount of gas held in storage for future use.

The amount of uncontracted transportation capacity as well as transportation capacity under short term contracts on a pipeline system determines the extent that seasonal demand will impact a pipeline system s revenue. Pipeline systems that have a higher ratio of long-term contracts (contracts with a duration longer than one year) will be impacted less by seasonal demand. Conversely, for those pipeline systems with more available capacity, or operating under short term contracts, fluctuations in demand between seasons can impact revenue. Pipeline systems which have a tariff that includes seasonal rates for short term service may be able to mitigate the potential negative impact of seasonal fluctuations in demand.

Great Lakes - As a turbine based pipeline system, Great Lakes design day capacity at the Emerson inlet is approximately 2.45 Bcf/day during the winter and 2.3 Bcf/day during the summer (system fuel requirements utilize a portion of this capacity). Though the winter flow capability is higher than the summer capability, the market demand for Great Lakes long haul service can be higher in the summer when Great Lakes system has less transportation capacity.

The demand for Great Lakes long haul service is at its highest when natural gas is being delivered to natural gas storage areas. This is due to the approximate 880 Bcf of working gas storage located at the end of the Great Lakes system in Michigan and Ontario. The high demand period usually begins in the spring and extends through most of the summer. The transportation value across the Great Lakes pipeline system is at its highest in conjunction with storage fill requirements and electric power generation demand.

During the winter, there is also strong demand for Great Lakes services to meet the peak winter demand requirements of Northern Minnesota, Northern Wisconsin, and Michigan. These deliveries are met through Great Lakes short haul, long haul, and backhauls from storage. In fact, the aggregated peak day of all short haul and long haul flows occurs during the winter. Approximately ten per cent of Great Lakes flows were contracted on a short-term basis in 2007.

Great Lakes experiences significant winter volatility in the utilization of its long haul contracts due to downstream constraints on the Union Gas Limited and TransCanada systems. As the demand for storage withdrawals from the Dawn, Ontario storage facility increases to serve points east, so does the level of downstream constraints which may reduce shippers ability to use Great Lakes transportation services to serve Eastern markets. This constraint may reduce demand for Great Lakes capacity during certain winter periods.

Northern Border - Seasonal supply and demand fundamentals are a growing influence on Northern Border s system throughput due to increased competition for WCSB supply and growing competition from alternate sources of supply, such as the Rockies, in the markets served by Northern Border. Demand for Northern Border s transportation has traditionally been the strongest during peak winter months to serve heating demand and peak summer months to serve electric cooling demand and storage injection. Demand conditions in other market regions for Canadian supply can impact the transportation value of Northern Border s system. For example, the Western U.S. market is sensitive to precipitation levels, which impact hydroelectric power generation. During the summer, high temperatures combined with low hydroelectric power generation levels can increase demand for Canadian natural gas in this region and shift supply away from Northern Border s system.

Northern Border s rate case settlement established seasonal rates for short-term service of less than one year that provide for higher maximum rates during anticipated peak usage periods and lower maximum rates during anticipated periods of reduced demand. Approximately 34 per cent of Northern Border s design capacity was contracted on a short-term basis in 2007.

Tuscarora **-** Tuscarora is almost fully contracted under long-term contracts (approximately 97 per cent contracted with a weighted average remaining contract life of 10.4 years) at December 31, 2007. As a result, fluctuations in revenue due to seasonality are minimal.

Supply

North American Supply

The primary source of natural gas transported by all of our pipeline systems is the WCSB. For this reason, the continuous supply of Canadian natural gas is crucial to the long-term financial condition of our pipeline systems.

As of December 2006, the WCSB had remaining discovered natural gas reserves of approximately 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, additional reserves have continually been discovered to maintain the reserves-to-production ratio at close to nine years. It is expected that producers will continue to explore and develop new fields, particularly in the Northeastern and West central foothills regions of Alberta, Canada. There will also be significant activity aimed at unconventional resources such as coal bed methane.

The amount of WCSB natural gas available for export is the most significant factor affecting the volume of natural gas transported by our pipeline systems. The amount of WCSB natural gas available for export is determined by:

- WCSB natural gas production levels;
- demand for WCSB natural gas; and
- storage capacity for WCSB natural gas and demand for storage injection.

The extent to which WCSB natural gas available for export will be transported on each pipeline system is affected by:

- demand for WCSB natural gas in different U.S. consumer markets;
- available transportation capacity and related market pricing options on our competitors pipelines;
- natural gas from other supply sources that can be transported to our customer markets;
- the natural gas market price spread between Alberta, Canada and the applicable market which reflects the relative supply and demand for WCSB natural gas in Canada and in the U.S.; and

- storage capacity in the U.S. and Canada and the related demand for storage injection.

Our Pipeline Systems

In 2007, approximately 84 per cent, 82 per cent and 92 per cent of the natural gas transported by Great Lakes, Northern Border and Tuscarora, respectively, was produced in Canada.

Great Lakes receives natural gas from interconnections with the TransCanada Mainline, ANR and from storage facilities. Gas received from the interconnection with the TransCanada Mainline at Emerson, Manitoba is WCSB supply. ANR is connected with numerous other pipelines, sourcing gas from virtually all North American basins as well as imported LNG.

Northern Border is also connected directly with other natural gas supplies. Natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana accounted for approximately 12 per cent of the natural gas Northern Border transported in 2007. The remaining natural gas transported by Northern Border was synthetic gas produced at the Dakota Gasification plant in North Dakota.

Tuscarora receives natural gas from its interconnection with GTN. GTN is interconnected with WCSB supply as well as natural gas from the Rockies and other U.S. basins.

CUSTOMERS, COMPETITION AND CONTRACTING

Customers

Great Lakes - The largest customer for Great Lakes capacity is TransCanada, through its mainline pipeline system. This capacity is used by TransCanada customers to transport Western Canadian gas to Eastern Canadian and U.S. markets. ANR also holds capacity on Great Lakes to integrate its Michigan storage locations with its Wisconsin pipeline system. Various local distribution companies in Minnesota, Wisconsin and Michigan contract for transportation on Great Lakes to add Canadian gas to their supply mix. In addition, natural gas marketing and trading companies and producers hold transportation capacity on Great Lakes, either directly or through the capacity release program, and use Great Lakes flexibility to deliver gas to markets, interconnecting pipelines and storage facilities along its system to maximize the value of their transportation contracts.

For the year ended December 31, 2007, TransCanada and ANR contracts represented approximately 45 per cent and three per cent, respectively, of Great Lakes revenue. Great Lakes did not have any other customers contributing more than 10 per cent of their 2007 revenues.

Although Great Lakes has traditionally operated under long-term contracts, in response to changing market conditions, it markets its capacity on a shorter-term basis to a wide variety of customers, including producers, natural gas marketing and trading companies and LDCs in the U.S. and Canada.

Northern Border - Northern Border serves Midwestern U.S. markets for customers located throughout North America. Northern Border s customers include natural gas producers, marketing and trading companies, industrial facilities, local distribution companies and electric power generating plants.

For the year ended December 31, 2007, contracts with BP Canada Energy Marketing Corp., Nexen Marketing, U.S.A., Inc. and Cargill Inc. represented approximately 16 per cent, 14 per cent and 14 per cent, respectively, of Northern Border s revenue.

Tuscarora - Tuscarora serves markets in Oregon, Northern California and Northern Nevada. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power. Tuscarora s customers include power generation companies, local distribution companies, and a variety of industrial, commercial, and other companies.

For the year ended December 31, 2007, contracts with Sierra Pacific Power, Southwest Gas Company and Barrick Goldstrike Mines represented approximately 72 per cent, 13 per cent and 11 per cent, respectively, of Tuscarora s revenue.

Competition

Competition among natural gas pipelines is based primarily on transportation charges and proximity to natural gas supply areas and markets. Our pipeline systems face competition at both the supply and market ends of their pipeline systems where other pipelines access the same supply basins and/or deliver to markets served by our respective pipelines. Other pipelines access the WCSB supply basin and provide alternative routes for shippers to access markets served by our systems. Additionally, other pipelines bring supply sourced from other U.S. supply basins into our market areas.

Great Lakes - Great Lakes principal business comes from its position as a link in the chain of pipelines that facilitate the transportation of natural gas from Western Canada to Eastern Canadian markets. Natural gas is transported by TransCanada from Western Canada to near Emerson, Manitoba, from Emerson to St. Clair, Michigan by Great Lakes, and from St. Clair to Dawn, Ontario and points further east by TransCanada. The primary competition for Great Lakes is the alternate route from Western Canada to Dawn on TransCanada s Mainline. Other routes from Western Canada to Ontario, Canada, are the Foothills Pipeline to Northern Border to Vector Pipeline route and the Alliance Pipeline to Vector Pipeline route. In addition, gas sourced from the U.S. Rockies, U.S. Mid-Continent and U.S. Gulf Coast can be delivered to Chicago and then to Ontario via the Vector Pipeline.

Northern Border **-** Northern Border s system competes for natural gas supply with other pipelines that transport Western Canadian natural gas to markets in the West, Midwest and East in North America, including TransCanada and Alliance Pipeline. Northern Border also competes for demand for transportation services with other pipelines that provide the markets it serves with access to natural gas storage facilities, and with alternate sources of supply, such as the Rockies, the Mid-Continent, the Permian Basin and the Gulf Coast, and LNG. A new competitor is the REX-West segment of the 1,679 mile Rockies Express Pipeline system from Rio Blanco County, Colorado to Monroe County, Ohio, which is increasing supply competition in Midwestern markets and could cause Northern Border to discount their rates or otherwise experience a reduction in their revenues.

Tuscarora **-** Shippers of natural gas from the WCSB have other options for transporting Canadian natural gas to markets throughout Canada and the U.S.

Tuscarora s primary competition in the Northern Nevada natural gas transmission market is with Paiute Pipeline Company (Paiute), owned by Southwest Gas Co. of Las Vegas, Nevada. Paiute interconnects with Northwest Pipeline Corp. at the Nevada-Idaho border and transports natural gas from British Columbia and the U.S. Rocky Mountain Basin to the Northern Nevada market.

Contracting

As existing contracts on our pipeline systems approach their expiration dates, efforts are made to extend and/or renew the contracts. The ability to extend and/or renew expiring contracts will depend upon competitive alternatives, the regulatory environment, and market and supply factors. The duration of new or renegotiated contracts will be affected by current market price spreads, transportation rates, competitive conditions, and judgments concerning future market trends and volatility. If market conditions are not favorable at the time of renewal, then transportation capacity may be uncontracted until market conditions become more favorable. Subject to regulatory requirements, our pipeline systems attempt to recontract or remarket their capacity at the maximum rates allowed under their tariffs. However, a pipeline system may discount capacity under certain circumstances in order to maximize revenue.

Great Lakes **-** Existing transportation contracts mature at varying times and in varying amounts of throughput capacity. Approximately four per cent of Great Lakes contracted capacity expired in 2007 and 15 per cent will expire by December 31, 2008 in the absence of extensions or renewals of this capacity. In addition, ANR holds over 1,100 Mdth/d of capacity on Great Lakes that is expected to be renewed annually. For the year ended December 31, 2007, Great Lakes average contracted capacity compared was 106 per cent.

Northern Border **-** Northern Border contracted 97 per cent of its design capacity on a firm basis in 2007, some of which was sold at a discount to maximize overall revenue on the Port of Morgan, Montana to Harper, Iowa portion of the pipeline. As of January 31, 2008, Northern Border had 37 per cent of its design capacity uncontracted beginning in the second quarter of 2008 and 48 per cent uncontracted by the end of 2008. Refer to Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations for further discussion.

Tuscarora Tuscarora s average contracted capacity for the year ended December 31, 2007 was 96 per cent. Tuscarora has firm transportation contracts for 97 per cent of its available contracted capacity, as at January 31, 2008. This includes contracts held by Sierra Pacific Power for 69 per cent of the total available capacity, the majority of which expire on October 31, 2017.

REGULATORY ENVIRONMENT

Government Regulation

Great Lakes, Northern Border, and Tuscarora are regulated under the Natural Gas Act of 1938, Natural Gas Policy Act of 1978, and Energy Policy Act of 2005, which give the FERC jurisdiction to regulate virtually all aspects of their business, including:

- transportation of natural gas;
- rates and charges;
- terms of service and service contracts with customers, including creditworthiness requirements;
- certification and construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- the acquisition and disposition of facilities;
- initiation and discontinuation of services; and

- standards of conduct for business relations with certain affiliates.

Rate Case, Great Lakes Great Lakes last rate settlement expired on October 31, 2005 with no requirement to file a new rate proceeding or settlement.

Rate Case, Northern Border - In November 2006, the FERC approved the settlement with Northern Border s customers of its 2005 rate case to be effective January 1, 2007. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border s system. Northern Border s overall rates were reduced, compared with rates prior to the filing, by approximately 5 per cent. The settlement also provided for seasonal rates for short-term transportation services. The settlement included a three-year moratorium on filing rate cases and participants challenging Northern Border s rates and requires that Northern Border file a rate case within six years from the date the new rates went into effect.

Cost and Revenue Study, Tuscarora - As a result of an obligation to file a cost and revenue study with the FERC pursuant to an agreement with the PUCN, Tuscarora, Sierra Pacific Power and the PUCN entered into settlement discussions with respect to a potential rate adjustment in 2006. In April 2006, the PUCN and Sierra Pacific Power agreed to a settlement with Tuscarora, which was subsequently approved by the FERC in July 2006. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006, or a 17 per cent reduction to the previous rate of $0.481/dth-day. The settlement also included a moratorium on all rate actions before the FERC by any party to the settlement until May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate.

Income Tax Allowance In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the rates for partnership interests held by partners with an actual or potential income tax liability. On December 16, 2005, the FERC issued an order (the December 16 Order) in its first case-specific review of the income tax allowance issue, reaffirming its tax allowance policy and directing the pipeline to provide certain evidence necessary to determine the income tax allowance. The FERC s new policy and the December 16 Order were appealed; however, the United States Court of Appeals for the D.C. Circuit subsequently denied the petitions for review and upheld the FERC s income tax allowance policy.

On December 26, 2007, the FERC issued an order (the December 26 Order) which upheld and clarified its methodology for determining a partnership s income tax allowance in a rate case. In the future, partnerships will be required to prove (1) that its partners have an actual or potential income tax liability, which is determined by the partner s obligation to file a return that recognizes either a taxable gain or loss; (2) its partners marginal Federal income tax rates, if higher than the commission s default rates of 28 per cent for individuals and 34 per cent for corporations, and (3) the partners marginal state income tax rates. If the FERC were to disallow a portion of the income tax allowance for one of our pipeline systems in a rate case, it may cause its recourse rate to be set at a level that is different, or lower, than the level otherwise in effect.

Composition of Proxy Groups for Rates of Return Determinations - On July 19, 2007, the FERC issued a policy statement proposing to update its standards regarding the composition of proxy groups for determining the appropriate returns on equity for natural gas and oil pipelines. The proposed policy statement would permit the inclusion of master limited partnerships (MLPs) in the proxy group for purposes of calculating returns on equity under the Discounted Cash Flow (DCF) analysis. This is a change from its prior view that MLPs should not be included in the proxy group. Specifically, the FERC proposes that MLPs may be included in the proxy group provided that the distributions used in the DCF analysis are capped at the pipeline s reported earnings level. According to the proposed policy statement, the return on equity under the DCF analysis is calculated by adding the dividend or distribution yield (dividends divided by share/unit price) to the projected future growth rate of dividends or distributions. The future growth rate is weighted based on the long-term growth of the economy and the short-term growth for the pipeline. Additionally, the decision as to whether an MLP is included in the proxy group will be made on a case by case basis and will be based on stability of the MLP s earnings over a number of years. The FERC is currently evaluating the merit of the new policy statement through comments, reply comments and technical conferences. The FERC s proposed policy statement is subject to change based on comments filed and the outcome of the technical conference and therefore we cannot predict the impact or timing of the final policy statement.

Energy Affiliates In November 2003, the FERC adopted revised standards of conduct which govern the relationships between regulated interstate natural gas pipelines and their energy affiliates. The new standards of conduct were designed to prevent interstate natural gas pipelines from giving any undue preference to their energy affiliates and ensure that transmission service is provided on a nondiscriminatory basis. In November 2006, the United States Court of Appeals for the District of Columbia vacated the FERC s order regarding standards of conduct for energy affiliates of natural gas pipelines and remanded the matter back to the FERC. On January 9, 2007, the FERC issued Order No. 690, Standards of Conduct for Transmission Providers (the Interim Rule) as the Commission s interim response to the Appeals Court decision. The Interim Rule reduced the application of the standards of conduct for interstate natural gas pipelines to the relationship between the pipelines and their marketing affiliates as defined in the FERC s rules that were in effect prior to the current regulations and made certain other revisions that were subject to the appeal. Requests for clarifications and in the alternative rehearing of the Interim Rule have been filed. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking, which if accepted as the final rule, will make permanent the Interim Rule s applicability of the standards of conduct to govern the relationship between interstate natural gas pipelines and their marketing affiliates.

Market Manipulation In January 2006, the FERC issued a final rule making it unlawful for any entity subject to its jurisdiction that directly or indirectly purchases or sells natural gas, transportation services or electric energy to defraud, using any device, scheme or artifice; make untrue statements of a material fact or omit a material fact; or engage in any act, practice or course of business that operates as a fraud. The maximum civil penalty under these statutes is $1 million per day, per violation.

Environmental and Safety Matters

All of our pipeline systems operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. Such laws and regulations generally require natural gas pipelines to obtain and comply with a wide variety of environmental registrations, licenses, permits, and other approvals. These laws and regulations also can restrict or impact business activities in many ways, such as restricting the way wastes are handled or disposed of; requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators; and enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations.

Pipeline Safety Our pipeline systems are subject to U.S. Department of Transportation pipeline integrity management regulations. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity assessments on pipeline segments that exist in densely populated areas or near specifically identified sites that are designated as high consequence areas. Pipeline companies are required to perform the integrity assessments within ten years of the date of enactment and perform subsequent integrity assessments on a seven-year cycle. All of our pipeline systems had performed the required assessments of 50 per cent of the highest priority high consequence areas by the end of 2007.

Waste Management The operations of our pipeline systems generate hazardous and non-hazardous solid wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and non-hazardous solid wastes. For instance, RCRA prohibits the disposal of certain hazardous wastes on land without prior treatment, and requires generators of wastes subject to land disposal restrictions to provide notification of pre-treatment requirements to disposal facilities that are in receipt of these wastes. Generators of hazardous wastes also must comply with certain standards for the accumulation and storage of hazardous wastes, as well as with recordkeeping and reporting requirements applicable to hazardous waste storage and disposal activities.

Site Remediation - The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as Superfund, and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons considered to be responsible for the release of hazardous substances into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies.

Our pipeline systems currently own or lease properties that for many years have been used for the transportation and compression of natural gas. These properties and the substances released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, our pipeline systems could be required to remove any previously disposed wastes, including waste disposed of by prior owners or operators; remediate contaminated property, including groundwater contamination, whether from prior owners or operators or other historic activities or spills; or perform remedial closure operations to prevent future contamination.

Air Emissions - The Clean Air Act (CAA) and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase of existing air emissions; application for, and strict compliance with, air permits containing various emissions and operational limitations; or the utilization of specific emission control technologies to limit emissions.

Water Discharges - The Clean Water Act (CWA) and analogous state laws impose strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the Environmental Protection Agency (EPA) or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Federal and state regulatory agencies may impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Activities on Federal Lands - Natural gas transportation activities are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. The current activities of our pipeline systems, as well as any proposed plans for future activities, on federal lands are subject to the requirements of NEPA.

Other Laws and Regulations - Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases.

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security (DHS) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS is currently in the process of adopting regulations that will determine whether some of our pipeline facilities or operations will be subject to additional DHS-mandated security requirements.

Title to Properties

Our pipeline systems hold all rights, titles and interests in their pipeline system. With respect to real property, our pipeline systems own sites for compressor stations, meter stations, pipeline field offices, microwave towers and a corporate office. Our pipeline systems also derive interests from leases, easements, rights-of-way, permits and licenses from landowners or governmental authorities permitting land use for construction and operation of their pipelines.

Great Lakes - Approximately 74 miles of Great Lakes pipeline system are located within the boundaries of three Indian reservations: the Leech Lake Chippewa Indian Reservation and the Fond du Lac Chippewa Indian Reservation in Minnesota, and Bad River Chippewa Indian Reservation in Wisconsin. In 1968, Great Lakes obtained right-of-way across allotted lands located within each of the reservations boundaries. All of the allotted lands are subject to a 50 year easement granted by the Bureau of Indian Affairs (BIA) for and on behalf of the individual Indian owners or the reservations. These tracts are subject to right-of-way permits issued by the BIA that expire in 2018. Also, the Great Lakes pipeline crosses approximately 1000 ft. in two tracts in Lower Michigan, which are located within the Chippewa Indian Reservation, under perpetual easements.

Northern Border - Approximately 90 miles of Northern Border s pipeline system are located within the boundaries of the Fort Peck Indian Reservation in Montana. In 1980, Northern Border entered into a pipeline right-of-way lease with the Fort Peck Tribal Executive Board on behalf of the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. This pipeline right-of-way lease granted Northern Border the right to construct and operate its pipeline on certain tribal lands. The pipeline right-of-way lease expires in 2011, although Northern Border has an option to renew the pipeline right-of-way lease through 2061. In conjunction with obtaining a right-of-way across tribal lands located within the exterior boundaries of the Fort Peck Indian Reservation, Northern Border also obtained right-of-way across allotted lands located within the reservation boundaries. Most of the allotted lands are subject to a perpetual easement granted by the BIA for and on behalf of the individual Indian owners or obtained through condemnation. Several tracts are subject to a right-of-way grant that expires in 2015.

Insurance

The Partnership s operations and activities are insured under TransCanada insurance programs, including property insurance, liability, automobile liability and workers compensation, in amounts which management believes are reasonable and appropriate.

Employees

The Partnership does not have any employees. In addition, none of our pipeline systems directly employ any of the persons responsible for managing or operating the pipeline systems or for providing them with services related to their day-to-day business affairs. Subsidiaries of TransCanada are the operators of all of our systems.

AVAILABLE INFORMATION

Our website is www.tcpipelineslp.com. We make available free of charge, on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing or furnishing such reports with the SEC. Information contained on our web site is not part of this report.

Item 1A. Risk Factors

Cautionary Statement Regarding Forward-Looking Information

A number of statements made by TC PipeLines, LP in this Form 10-K filing are forward-looking and relate to, among other things, anticipated financial performance, business prospects, strategies, market forces and commitments. Much of this information appears in Management s Discussion and Analysis of Financial Condition and Results of Operations found herein. All forward-looking statements are based on the Partnership s current beliefs as well as assumptions made by and information currently available to the Partnership. These statements reflect the Partnership s current views with respect to future events. The Partnership assumes no obligation to update any such forward looking statements to reflect events or circumstances occurring after the date hereof. Words such as anticipate, believe, estimate, expect, plan, intend, forec similar expressions, identify forward-looking statements. By its nature, such forward-looking information is subject to various risks and uncertainties, including the risk factors discussed under Item 1A. Risk Factors , which could cause TC PipeLines actual results and experience to differ materially from the anticipated results or other expectations expressed in this

Form 10-K. Readers are cautioned not to place undue reliance on this forward-looking information, which is as of the date of this Form 10-K.

Each of the risks and uncertainties described below could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations and cash flows, including our ability to make distributions to our unitholders.

All of the information included in this report and any subsequent reports we may file with the SEC or make available to the public should be carefully considered and evaluated before investing in any securities issued by us.

The risks referred to herein refer to risks inherent in the Partnership and our pipeline systems.

RISKS INHERENT IN OUR BUSINESS

Cash distributions are dependent primarily on our cash flow, financial reserves and working capital borrowings.

Cash distributions are not dependent solely on our profitability, which is affected by non-cash items. Therefore, we may make cash distributions during periods when losses are reported and may not make cash distributions during periods when we report profits.

Factors that affect the actual amount of cash that we will have available for distribution to our unitholders include the following:

- the amount of cash set aside and the adjustment in reserves made by our general partner in its sole discretion;
- the level of capital expenditures made by our pipeline systems;
- the required principal and interest payments on our debt, retirement of debt and other liabilities including cost of acquisitions;
- the amount of cash distributed to us by the entities in which we own a non-controlling interest;
- our ability to borrow funds and access capital markets including the issuance of debt and equity securities; and
- restrictions on distributions contained in debt agreements.

We are dependent on our pipeline systems to generate sufficient cash to enable us to pay distributions.

The amount of cash we have quarterly to distribute to our common unitholders depends upon numerous factors, most of which are beyond our control and the control of our general partner, including:

- the rates charged and the volumes under contract for the transportation services of our pipeline systems;
- the quantities of natural gas available for transport and the demand for natural gas;
- legislative or regulatory action affecting demand for and supply of natural gas, and the rates our pipeline systems are allowed to charge in relation to their operating costs;
- the level of our pipeline systems operating costs; and
- the creditworthiness of our pipeline systems shippers.

If we do not identify opportunities for accretive growth through organic projects or acquisitions, or our pipeline systems do not successfully complete expansion projects or make and integrate acquisitions that are accretive, our future growth may be limited.

A principal focus of our strategy is to continue to grow the cash distributions on our units by expanding our business. Our ability to grow depends on our ability to undertake acquisitions and organic growth projects, and the ability of our pipelines systems to complete expansion projects and make acquisitions that result in an increase in cash per unit generated from operations.

The long-term financial conditions of our pipeline systems are dependent on the continued availability of Western Canadian natural gas for import into the U.S. and the market demand for these volumes. Competition from pipelines that deliver natural gas from other supply sources to our pipeline systems market areas could cause our pipeline systems to discount their rates or otherwise experience a reduction in their revenues.

The development of additional natural gas reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to pipelines that interconnect with our pipeline systems. High exploration and production costs, low prices for natural gas, regulatory limitations such as royalty frameworks, or the lack of available capital for these projects could adversely affect the development of additional reserves in Western Canada and the production in the WCSB.

Volumes available for export out of the WCSB depend in part on the internal demand for Canadian natural gas which may increase as a result of increased demand for electricity generation and other industrial requirements, including the development of oil sands projects, which may require substantial amounts of natural gas. This higher internal demand may reduce the amount of gas available for import into the U.S. In the longer term, a portion of the Alberta hub gas supply may come from proposed gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada and from the continued growth of coal bed methane projects. Cancellation or delays in the construction of such pipelines or such projects could adversely affect the volumes available for export in the long term.

If the availability of Alberta hub natural gas was to decline, existing shippers on our pipeline systems may be unlikely to extend their contracts and our pipeline systems may be unable to find replacement shippers for lost capacity. Furthermore, additional natural gas reserves may not be developed in commercial quantities and in sufficient amounts to fill the capacities of each of our pipeline systems.

In addition, existing customers may not extend their contracts if the cost of delivered natural gas from other producing regions into the markets served by our pipeline systems is lower than the cost of natural gas delivered by our pipeline systems. Our pipeline systems face increased competition from other pipelines that provide access for our shippers to capacity from the U.S. Rocky Mountain Region. The Rockies Express Pipeline owned by Rockies Express Pipeline LLC is being constructed in three phases and the planned terminus is in Clarington, Ohio. The first phase of The Rockies Express Pipeline is completed and currently delivering gas to interconnects in the Midwestern region. The Rockies Express Pipeline could result in significant downward pressure on natural gas prices in the Mid-continent Region, which could have an impact on Northern Border or Great Lakes.

An increase in competition in the key markets served by our pipeline systems could arise from new ventures or expanded operations from existing competitors. Our financial performance depends to a large extent on the capacity contracted on our pipeline systems. Decreases in the volumes transported by our pipeline systems, whether caused by supply or demand factors in the markets these pipeline systems serve, competition or otherwise, can directly and adversely affect our revenues and results of operations.

Our pipeline systems may not be able to maintain existing customers or acquire new customers when the current shipper contracts expire or customers may choose to recontract for shorter periods or at less than maximum rates.

The ability to extend and replace contracts on terms comparable to prior contracts or on any terms at all, could be adversely affected by factors, including:

- the supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply in the U.S.;
- competition from other pipelines, including their transportation rates or through their access to upstream supplies, as well as the proposed construction by other companies of additional pipeline capacity;
- the price of, and demand for, natural gas in markets served by our pipeline systems; and
- regulatory actions.

Ongoing changes in these factors and customers ability to adjust to changing market conditions may cause Great Lakes and Northern Border to sell a significant portion of available capacity on a short-term basis. The weighted average life of Great Lakes and Northern Border s contracts has generally declined over time. As of January 31,

2008, the weighted average remaining lives of Great Lakes and Northern Border s contracts were 2.4 years and 1.3 years, respectively. Additionally, if the forward natural gas basis differentials do not support maximum rates, they may sell portions of their capacity at discounted rates. Any inability by Great Lakes and Northern Border to renew existing contracts at maximum rates or at all may have an adverse impact on their revenues and, as a result, cash distributions made to us.

If any significant shipper fails to perform its contractual obligations, our pipeline systems respective cash flows and financial condition could be adversely impacted.

As of December 31, 2007, each of our pipeline systems has customers that account for more than ten per cent of their revenue. The loss of all or even a portion of the revenues associated with these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on the financial condition, results of operations and cash flows of our pipeline systems, unless they were able to contract for comparable volumes from other customers at favorable rates.

Sierra Pacific Power is Tuscarora s largest shipper, with firm contracts for approximately 69 per cent of its capacity. Sierra Pacific Resources and Sierra Pacific Power have non-investment grade credit ratings.

Our pipeline systems transportation rates are subject to review and possible adjustment by federal regulators. If the FERC requires that our pipeline systems tariff be changed, their respective cash flows may be adversely affected.

Under the Natural Gas Act (NGA), interstate transportation rates must be just and reasonable and not unduly discriminatory. Our pipeline systems are subject to extensive regulation by the FERC. The FERC s regulatory authority is not limited to but extends to matters including:

- transportation of natural gas;
- rates and charges;
- operating terms and conditions of service including creditworthiness requirements;
- types of services our pipeline systems may offer to their customers;
- construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- the acquisition and disposition of facilities;

- initiation and discontinuation of services; and
- standards of conduct business relations with certain affiliates.

Given the extent of regulation by the FERC and potential changes to regulations, we cannot predict:

- the likely federal regulations under which our pipeline systems will operate in the future;
- the effect that regulation will have on financial position, results of operations and cash flows of our pipeline systems and ourselves; or
- whether our cash flow will be adequate to make distributions to unitholders.

Great Lakes last rate settlement expired on October 31, 2005 with no requirement to file a new rate proceeding or settlement. Northern Border and Tuscarora are currently operating under rate settlements which precludes a party to the rate settlements from bringing any rate actions prior to December 31, 2009 and May 31, 2010, respectively.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our pipeline systems ability to establish or charge rates that would cover future increase in their costs, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot assure unitholders that our pipeline systems will be able to recover all of their costs through existing or future rates.

Should our pipeline systems fail to comply with all applicable FERC administered statutes, rules, regulations and orders, our pipeline systems could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

Finally, we cannot give any assurance regarding the future regulations under which our pipeline systems will operate their natural gas transportation businesses, or the effect such regulations could ultimately have on our financial condition, results of operations and cash flows.

If our pipeline systems do not maintain their respective rate bases, the amount of revenue attributable to the return on the rate base they collect from their shippers will decrease over time.

Our pipeline systems are generally allowed to collect from their customers a return on their assets or rate base as reflected in their financial records as well as recover that rate base through depreciation. In the absence of additions to the rate base through capital expenditures, the amount they may collect from customers decreases as the rate base declines as a result of, among other things, depreciation and amortization.

Our pipeline systems pipeline integrity programs may impose significant costs and liabilities.

The U.S. Department of Transportation rules require pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as high consequence areas. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the total costs of compliance with this rule because those costs will depend on the extent of the pipeline testing and any subsequent repairs found to be necessary. Our pipeline systems completed the required 50 per cent inspection of their respective pipelines highest priority highest consequence segments of lines by the end of 2007. The remaining 50 per cent of each pipeline s highest priority highest consequence segments of pipeline is required to be inspected, and repaired if necessary, by 2012. After that point, the inspection is required to reoccur every seven years. Once 100 per cent of our pipeline systems have been inspected, we will have a better understanding of the total ongoing costs. Our pipeline systems will continue their pipeline integrity testing programs to assess and maintain the integrity of the pipelines. The results of this work could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of their pipelines.

Our pipeline systems operations are regulated by federal, state and local agencies responsible for environmental protection and operational safety.

Risks of substantial costs and liabilities are inherent in pipeline operations and each of our pipeline systems may incur substantial costs and liabilities in the future as a result of stricter environmental and safety laws, regulations, and enforcement policies and claims for personal or property damages resulting from our pipeline systems operations. Moreover, new, stricter environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems compliance costs or the cost of any remediation of environmental contamination that may become necessary, and these costs could be material. For instance, the U.S. Congress is actively considering federal legislation to reduce emissions of greenhouse gases (including carbon dioxide and methane). Several states of the U.S. have already taken legal measures to reduce emissions of greenhouse gases, and many other nations, not including the U.S., have also already agreed to regulate emissions of greenhouse gases. As a result of the regulation of greenhouse gases in the U.S., we may incur increased compliance costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; and (iii) administer and manage any greenhouse gas emissions reduction program that may be applicable to our operations. In addition, laws and regulations to reduce emissions of greenhouse gases could affect the consumption of natural gas and consequently, adversely affect the demand for our pipeline services and the rates we are able to collect for those services. If our pipeline systems are not able to recover these costs, cash distributions to unitholders could be adversely affected.

Our pipeline systems indebtedness may limit their ability to borrow additional funds, make distributions to us or capitalize on business opportunities.

As of December 31, 2007, Great Lakes, Northern Border and Tuscarora had $440 million, $616 million and $66 million of debt outstanding, respectively. Their respective levels of debt could have important consequences to Great Lakes, Northern Border and Tuscarora, including the following:

- their ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- they will need a portion of their cash flow to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to us, which will reduce our ability to make distributions to our unitholders;
- their debt level may make them more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- their debt level may limit their flexibility in responding to changing business and economic conditions.

Our pipeline systems ability to service their debt will depend upon, among other things, future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond their control.

In addition, under the terms of these financing arrangements, our pipeline systems are prohibited from making cash distributions during an event of default under their debt instruments. Under Great Lakes debt instruments, Great Lakes has limitations on the level of indebtedness and has other restrictions, including a general prohibition against liens on pipeline facilities. Provisions in Northern Border s debt instruments limit its ability to incur indebtedness and engage in specific transactions. This could reduce its ability to capitalize on business opportunities that arise in the course of its business. Under Tuscarora s debt instruments, Tuscarora has granted a security interest in certain of its transportation contracts, which is available to noteholders upon an event of default. In addition, the Partnership s third party credit facility requires us to maintain certain financial ratios and contains restrictions on incurring additional debt and making distributions to partners.

We do not own a controlling interest in Great Lakes or Northern Border and we may be unable to cause certain actions to take place unless the other partner agrees. As a result, we will be unable to control the amount of cash we will receive from those operations and we could be required to contribute significant cash to fund our share of their operations. If we fail to make these contributions our ownership interest would be diluted.

The major policies of Great Lakes and Northern Border are established by each of their Management Committees.

Great Lakes Management Committee consists of up to six members, three of whom are designated by us and three of whom are designated by TransCanada. Currently the committee consists of four appointed members, two of whom are designated by us and two of whom are designated by TransCanada. All decisions by the Management Committee require unanimous consent. An Executive Committee which consists of up to three members: one Partnership Committee Member, one TransCanada Committee Member and the Great Lakes President, a non-voting member. Currently this committee consists of two appointed members: one Partnership Committee Member and one TransCanada Committee Member, who also serves as the Great Lakes president. The Executive Committee has all of the powers of the Management Committee in the management of Great Lakes business. Because of these provisions, without the concurrence of TransCanada, we may be unable to cause Great Lakes to take or not to take certain actions, even though those actions may be in the best interest of us or Great Lakes.

Northern Border s Management Committee consists of four members, two of whom are designated by us and two of whom are designated by an affiliate of ONEOK. The Management Committee requires the affirmative vote of a majority of the partners ownership interests to act on most activities. Certain activities require the unanimous consent of the committee, such as the filing of the application for regulatory authority to construct and operate new facilities and any changes to the cash distribution policy. Because of these provisions, without the concurrence of ONEOK, we may be unable to cause Northern Border to take or not to take certain actions, even though those actions may be in the best interest of us or Northern Border.

Great Lakes and Northern Border may require us to make additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. Additionally, in the event we elect not to, or are unable to, make a required capital contribution to Great Lakes or Northern Border, our ownership interest would be diluted.

Our pipeline systems operations are subject to operational hazards and unforeseen interruptions, which could adversely affect their businesses and for which they may not be adequately insured.

Our pipeline systems operations are subject to all of the risks and hazards typically associated with the operation of natural gas transportation pipeline systems. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes, and the performance of pipeline facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, the collision of equipment with our pipeline systems pipeline facilities (which may occur if a third party were to perform excavation or construction work near these facilities), and catastrophic events such as explosions, fires, earthquakes, floods or other similar events beyond our pipeline systems control. It is also possible that our pipeline systems infrastructure facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred, and interruptions to the operation of our pipeline systems facilities, for short or extended durations, caused by such an event, could reduce revenues generated by our pipeline systems and increase expenses, thereby impairing their ability to meet their obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost. Should one of our pipeline systems experience such an event, it may have an adverse impact on our results of operations and cash flow.

Our pipeline systems do not own all of the land on which their pipelines and facilities are located, which could disrupt their operations.

Our pipeline systems do not own all of the land on which their pipelines and facilities are located, and they are, therefore, subject to the risk of increased costs to maintain necessary land use. They obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Their loss of these rights, through their inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on their financial condition, results of operations and cash flows.

If we were to lose TransCanada s management expertise, we would not have sufficient stand-alone resources to operate.

TransCanada, through wholly-owned subsidiaries, is the operator of all our pipeline systems. We do not presently have sufficient stand-alone management resources to operate without services provided by TransCanada. Further, we would not be able to evaluate potential growth opportunities and successfully complete acquisitions without TransCanada s resources.

RISKS INHERENT IN AN INVESTMENT IN THE PARTNERSHIP

The Partnership s indebtedness may limit its ability to borrow additional funds, make distributions or capitalize on business opportunities.

As of December 31, 2007, the Partnership had $573 million of debt outstanding. This substantial level of debt could have important consequences to the Partnership including the following:

- our ability to obtain additional financing, if necessary, for working capital, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- we will need a portion of our cash flow to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders; and

- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to service our debt will depend upon, among other things, the future financial and operating performance of our pipeline systems, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control.

In addition, our credit facilities contain restrictive covenants that may prevent us from engaging in certain transactions that we deem beneficial. These agreements require us to comply with various affirmative and negative covenants and maintaining certain financial ratios. There are restrictions and covenants with respect to:

- entering into mergers, consolidations and sales of assets;
- granting liens;
- material amendments to TC PipeLines partnership agreement;
- incurring additional debt; and
- distributions to partners.

Any future debt may contain similar restrictions.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

As of December 31, 2007, TC PipeLines had approximately $507 million outstanding under the Senior Credit Facility, all of which was at variable interest rates. As a result, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates. From time to time, we may enter into interest rate swap arrangements, which decrease our exposure to variable interest rates. At December 31, 2007, approximately 80 per cent of the variable interest rate exposure related to the Partnership s $507 million of debt outstanding under the Senior Credit Facility was mitigated by fixed interest rate swap arrangements.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to recapitalize by issuing more equity.

Unitholders have limited voting rights and do not control our general partner.

The general partner is our manager and operator. Unlike the holders of common stock in a corporation, holders of common units have only limited voting rights on matters affecting our business. Unitholders have no right to elect our general partner on an annual or other continuing basis. Our general partner may not be removed except by the vote of the holders of at least 66-$^{2}/_{3}$ per cent of the outstanding units and upon the election of a successor general partner by the vote of the holders of a majority of the outstanding common units. These required votes would include the votes of units owned by our general partner and its affiliates. The ownership of an aggregate of approximately 32 per cent of the outstanding units by our general partner and its affiliates has the practical effect of making removal of our general partner difficult.

In addition, the partnership agreement contains some provisions that may have the effect of discouraging a person or group from attempting to remove our general partner or otherwise change our management. If our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- any existing arrearages in the payment of the minimum quarterly distributions on the common units will be extinguished; and

- our general partner will have the right to convert its general partner interests and its incentive distribution rights into common units or to receive cash in exchange for those interests.

These provisions may diminish the price at which the common units will trade under some circumstances.The partnership agreement also contains provisions limiting the ability of unitholders to call meetings of unitholders or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management. Further, if any person or group other than our general partner or its affiliates or a direct transferee of our general partner or its affiliates acquires beneficial ownership of 20 per cent or more of any class of units then outstanding, that person or group will lose voting rights with respect to all of its units. As a result, unitholders will have limited influence on matters affecting our operations, and third parties may find it difficult to attempt to gain control of us, or influence our activities.

We may issue additional common units without unitholder approval, which would dilute existing unitholders interest. In addition, issuance of additional common units may increase the risk that we will be unable to pay the full minimum quarterly distribution on all common units.

Our general partner can cause us to issue additional common units, without the approval of unitholders, in the following circumstances:

- under employee benefit plans, if any;
- upon conversion of the general partner interests and incentive distribution rights into common units as a result of the withdrawal of our general partner; or
- in connection with acquisitions or capital improvements that are accretive to our cash flow on a per unit basis.

In addition, we may issue an unlimited number of limited partner interests of any type without the approval of the unitholders. Based on the circumstances of each case, the issuance of additional common units or securities ranking senior to or on a parity with the common units may dilute the value of the interests of the then-existing holders of common units in the net assets of TC PipeLines and dilute the interests of unitholders in distributions by TC PipeLines. Our partnership agreement does not give the unitholders the right to approve the issuance by us of equity securities ranking junior to the common units at any time.

Any increase in the number of outstanding common units will increase the percentage of the aggregate minimum quarterly distribution payable to the common unitholders, which will in turn have the effect of increasing the risk that we will be unable to pay the minimum quarterly distribution in full on all the common units.

Unitholders may not have limited liability in some circumstances.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states. If it were to be determined that:

- TC PipeLines had been conducting business in any state without compliance with the applicable limited partnership statute, or

- the right or the exercise of the right by the unitholders as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under the partnership agreement constituted participation in the control of TC PipeLines business,

then unitholders could be held liable in some circumstances for TC PipeLines obligations to the same extent as a general partner. In addition, under some circumstances a unitholder may be liable to TC PipeLines for the amount of a distribution for a period of three years from the date of the distribution.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If our general partner and its affiliates, who currently own an aggregate of approximately 30.7 per cent of our common units, come to own 80 per cent or more of the common units, the general partner will have the right, which it may assign to any of its affiliates or us, to acquire all of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a consequence, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would desire to receive upon sale. Unitholders may also incur a tax liability upon a sale of their units.

Without the consent of each unitholder, Great Lakes, Northern Border or Tuscarora might be converted into a corporation, which would result in Great Lakes, Northern Border or Tuscarora, as the case may be, being subject to corporate income taxes.

If it becomes unlawful to conduct the business of Great Lakes, Northern Border or Tuscarora as a partnership and some other conditions are satisfied, the business and assets of Great Lakes, Northern Border or Tuscarora, as the case may be, will automatically be transferred to a corporation without the vote or consent of unitholders. Therefore, unitholders would not receive a proxy or consent solicitation statement in connection with that transaction. However, we believe that it is unlikely that circumstances requiring an automatic transfer will occur. A transfer to corporate form would result in Great Lakes, Northern Border or Tuscarora being subject to corporate income taxes and would likely be materially adverse to their, and therefore, our results of operations and financial condition.

TransCanada controls our general partner, which has sole responsibility for conducting our business and managing our operations. TC PipeLines GP, our general partner, and its affiliates have limited fiduciary responsibilities and may have conflicts of interest with respect to our partnership, and they may favor their own interests to the detriment of our unitholders.

The directors and officers of TC PipeLines GP and its affiliates have duties to manage TC PipeLines GP in a manner that is beneficial to its stockholders. At the same time, TC PipeLines GP has duties to manage our partnership in a manner that is beneficial to us. Therefore, TC PipeLines GP s duties to us may conflict with the duties of its officers and directors to its stockholders. Such conflicts may include, among others, the following:

- decisions of TC PipeLines GP regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional common units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and TC PipeLines GP;
- under our partnership agreement, TC PipeLines GP determines which costs incurred by it and its affiliates are reimbursable by us;
- affiliates of TC PipeLines GP may compete with us in certain circumstances;
- TC PipeLines GP may limit our liability and reduce our fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, unitholders are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- we do not have any employees and we rely solely on TC PipeLines GP and its affiliates to conduct our business, and
- TransCanada, through wholly-owned subsidiaries, is the operator of all of our pipeline systems. This operator role along with their ownership interest in Great Lakes may put TransCanada in a position to have to make decisions that may conflict as operator and/or owner of these systems.

Cost reimbursements due to our general partner may be substantial and could reduce our cash available for distribution.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred by our general partner and its affiliates on our behalf. During the year ended December 31, 2007, we paid fees and reimbursements to our general partner in the amount of $1.9 million. Our general partner in its sole discretion will determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions.

If we were found to be an investment company under the Investment Company Act of 1940, our contracts may be voidable and our offers of securities may be subject to rescission.

If we were deemed to be an unregistered investment company under the Investment Company Act, our contracts may be voidable and our offers of securities may be subject to rescission, and we may also be subject to other materially adverse consequences.

Our assets include a 46.45 per cent general partner interest in Great Lakes and a 50 per cent general partner interest in Northern Border. We could be deemed to be an investment company under the Investment Company Act if these general partner interests constituted an investment security , as defined in the Investment Company Act. If we were deemed to be an investment company , then we would be required to be registered as an investment company under the Investment Company Act. In that case, there would be a substantial risk that we would be in violation of the Investment Company Act because of the practical inability to register under the Investment Company Act.

Tax Risks

The Internal Revenue Service (IRS) could treat us as a corporation, which would substantially reduce the cash available for distribution to unitholders.

The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35 per cent. Distributions would generally be taxed again to unitholders as corporate distributions, and no income, gains, losses, deductions or credits would flow through to unitholders. Because a tax would be imposed upon us as an entity, the cash available for distribution to unitholders would be substantially reduced. Our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of the common units.

Current law may change so as to cause us to be taxable as a corporation for federal income tax purposes or otherwise to be subject to entity level taxation. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state or local income tax purposes, then specified provisions of the partnership agreement relating to distributions will be subject to change. These changes would include a decrease in distributions to reflect the impact of that law on us.

If our pipeline systems were to become subject to a material amount of entity level taxation for state tax purposes, then our pipeline systems operating cash flow and cash available for distribution to us and for other business needs would be reduced.

Our pipeline systems are partnerships or tax flow through entities, and as such they generally are not subject to income tax at the entity level. Several states are evaluating a variety of ways to subject partnerships to entity level taxation. One prevalent form of such taxation is a tax on gross receipts apportioned to a state. Imposition of such a tax on our pipeline systems by any state will reduce the cash available for distribution to us and for other business needs by our pipeline systems.

We have not requested an IRS ruling with respect to our tax treatment.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which the common units trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by some or all of the unitholders and the general partner.

Unitholders may be required to pay taxes on income from us even if they receive no cash distributions.

Unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their allocable share of our income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions equal to their allocable share of our taxable income or even the tax liability that results from that income.

Tax gains or losess on the disposition of common units could be different than expected.

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income that unitholders were allocated for a common unit which decreased their tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing a gain, may be ordinary income to unitholders. If the IRS successfully contests some conventions we use, unitholders could recognize more gain on the sale of common units than would be the case under those conventions without the benefit of decreased income in prior years.

Investors other than individuals who are U.S. residents may have adverse tax consequences from owning common units.

An investment in common units by tax-exempt entities, regulated investment companies and foreign persons raises issues unique to these persons. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Net income derived from the ownership of certain publicly traded partnerships is treated as qualifying income to a regulated investment company. Distributions to foreign persons will be reduced by withholding taxes. Foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We have registered as a tax shelter. This may increase the risk of an IRS audit of TC PipeLines or a unitholder.

We have registered as a tax shelter with the Secretary of the Treasury. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a one per cent interest in us has a very limited right to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in unitholders tax returns and may lead to audits of their tax returns and adjustments of items unrelated to us. Unitholders would bear the cost of any expenses incurred in connection with an examination of their personal tax return.

We treat a purchaser of common units as having the same tax benefits as the seller. A successful IRS challenge could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization conventions that do not conform to all aspects of specified Treasury regulations. A successful challenge to those conventions by the IRS could adversely affect the amount of tax benefits available to unitholders or could affect the timing of tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to unitholders tax returns.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

For income tax purposes and pursuant to the Partnership Agreement, when we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. If our valuation methodology were not sustained upon an IRS challenge, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Our valuation methodology is also used in certain computations and allocations relating to Section 743(b) adjustments and Section 751 deemed sale tax effects.

A successful IRS challenge to these methods, calculations or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The sale or exchange of 50 per cent or more of the total interest in our capital and profits will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 per cent or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Unitholders will likely be subject to state and local taxes as a result of an investment in units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. It is the unitholders responsibility to file all required United States federal, state and local tax returns. Counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

Item 1B. Unresolved Staff Comments

None.

Item 2 Properties

Excluding properties held directly by Tuscarora, TC PipeLines does not hold the right, title or interest in any properties.

Properties of Great Lakes Gas Transmission Limited Partnership, Northern Border Pipeline Company and Tuscarora Gas Transmission Company

See Item 1. Business for a description of our pipeline systems properties, their utilization, and how each property is held.

Item 3. Legal Proceedings

Our pipeline systems are parties to various legal actions arising in the normal course of business. Management believes the disposition of all known outstanding legal actions will not have a material adverse impact on the Partnership s financial condition, results of operations or cash flows.

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

There were no matters submitted to a vote of security holders, through solicitation of proxies or otherwise, during the year ended December 31, 2007.

PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The common units representing limited partner interests in the Partnership were issued pursuant to an initial public offering on May 28, 1999 and a private placement on February 22, 2007. The common units are quoted on the NASDAQ Global Select Market and trade under the symbol TCLP.

On February 22, 2007, the Partnership completed a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million. Net of issuing costs, the proceeds from the private placement were $594.4 million, which were used to fund a portion of the cash consideration for the Partnership s acquisition of a 46.45 per cent general partner interest in Great Lakes that closed concurrently with the private placement. TransCanada Northern purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported by the NASDAQ Global Select Market, and the amount of cash distributions per common unit declared with respect to the corresponding periods. Cash distributions are paid within 45 days after the end of each quarter to unitholders of record as of the record date.

	Price Range				Cash Distributions Declared per Common Unit	
	High		Low			
2007						
First Quarter	**$**	**37.54**	**$**	**35.29**	**$**	**0.600**
Second Quarter	**$**	**42.83**	**$**	**36.34**	**$**	**0.650**
Third Quarter	**$**	**40.69**	**$**	**32.98**	**$**	**0.655**
Fourth Quarter	**$**	**37.35**	**$**	**35.50**	**$**	**0.660**
2006						
First Quarter	$	35.14	$	32.60	$	0.575
Second Quarter	$	34.65	$	31.54	$	0.575
Third Quarter	$	33.50	$	30.41	$	0.575
Fourth Quarter	$	36.00	$	30.00	$	0.600

As of February 28, 2008, there were 96 registered holders of common units and approximately 13,800 beneficial owners of common units, including common units held in street name.

The Partnership currently has 34,856,086 common units outstanding, of which 24,142,935 are held by the public, 8,678,045 are held by TransCan Northern, and 2,035,106 are held by TC PipeLines GP. The common units represent an aggregate 98 per cent limited partner interest and the general partner interest represents an aggregate two per cent general partner interest in the Partnership.

The general partner receives two per cent of all cash distributions in regards to its general partner interest and is also entitled to incentive distributions as described below. The holders of common units (collectively referred to as unitholders) receive the remaining portion of the cash distribution. The Partnership s quarterly cash distributions to its unitholders comprise all of its Available Cash. Available Cash is defined in the partnership agreement and generally means, with respect to any quarter of the Partnership, all cash on hand at the end of a quarter less the amount of cash reserves that are necessary or appropriate, in the reasonable discretion of the general partner, to:

- provide for the proper conduct of the business of the Partnership (including reserves for future capital expenditures and for anticipated credit needs);
- comply with applicable laws or any Partnership debt instrument or agreement; or
- provide funds for cash distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

The general partner receives incentive distributions if the amount distributed with respect to any quarter exceeds the minimum quarterly distribution of $0.45 per common unit. Under the incentive distribution provisions, the general partner receives 15 per cent of amounts distributed in excess of $0.45 per common unit, 25 per cent of amounts distributed in excess of $0.5275 per common unit, and 50 per cent of amounts distributed in excess of $0.69 per common unit, provided the balance has been first distributed to unitholders on a pro rata basis. The amounts that trigger incentive distributions at various levels are subject to adjustment in certain events, as described in the partnership agreement.

In 2007, the Partnership made cash distributions to unitholders and the general partner that amounted to $86.7 million compared to $43.5 million in 2006. These payments represented $0.60 per common unit for the quarter ended December 31, 2006, $0.65 per common unit for the quarter ended March 31, 2007, $0.655 for the quarter ended June 30, 2007 and $0.66 per common unit for the quarter ended September 30, 2007. On February 14, 2008, the Partnership paid a cash distribution of $25.6 million to unitholders and the general partner, representing a cash distribution of $0.665 per common unit for the quarter ended December 31, 2007. The distribution was allocated in the following manner: $23.2 million to the holders of common units as of the close of business on January 31, 2008 (including $1.4 million to the general partner as holder of 2,035,106 common units and $5.8 million to TransCan Northern as holder of 8,678,045 common units), $1.9 million to the general partner as holder of incentive distribution rights, and $0.5 million to the general partner in respect of its two per cent general partner interest.

Item 6. Selected Financial Data

The selected financial data should be read in conjunction with the financial statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

(millions of dollars, except per unit amounts)	2007(1)	2006(2)	2005	2004	2003
	Year Ended December 31				
Income Data					
Equity income from investment in Great Lakes	**49.0**				
Equity income from investment in Northern Border	**61.2**	56.6	45.7	50.0	44.5
Equity income from investment in Tuscarora		5.9	7.5	7.5	5.3
Transmission revenues	**27.2**	0.9			
Financial charges, net and other	**(33.8)**	(15.8)	(1.0)	(0.5)	(0.1)
Net income	**89.0**	44.7	50.2	55.1	48.0
Basic and diluted net income per unit	**$ 2.51**	$ 2.39	$ 2.70	$ 2.99	$ 2.63
Cash Flow Data					
Cash distribution paid per unit	**$ 2.565**	$ 2.325	$ 2.300	$ 2.275	$ 2.175
Balance Sheet Data (at December 31)					
Total assets	**1,492.6**	777.8	315.7	332.1	288.1
Long-term debt (including current maturities)	**573.4**	468.1	13.5	36.5	5.5
Partners equity	**900.1**	303.9	301.6	294.9	282.0

(1)TC PipeLines acquired a 46.45 per cent interest in Great Lakes on February 22, 2007. The equity method is used to account for the Partnership s investment in Great Lakes.

(2)TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006 and began consolidating Tuscarora s operations upon acquisition of the additional 49 per cent general partner interest.

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

The following discusses the results of operations and liquidity and capital resources of TC PipeLines, along with those of Great Lakes, Northern Border and Tuscarora (together our pipeline systems) as a result of the Partnership s ownership interests.

The following discussions of the financial condition and results of operations of the Partnership and its pipeline systems should be read in conjunction with the financial statements and notes thereto of the Partnership, Great Lakes and Northern Border included elsewhere in this report. See Item 8. Financial Statements and Supplementary Data . For more detailed information regarding the basis of presentation for the following financial information, see the notes to the financial statements of the Partnership, Great Lakes and Northern Border. All amounts are stated in U.S. dollars.

PARTNERSHIP OVERVIEW

TC PipeLines was formed in 1998 as a Delaware limited partnership. TC PipeLines was formed by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America. Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

TC PipeLines, LP and its subsidiaries are collectively referred to herein as TC PipeLines or the Partnership. In this report, references to we , us our collectively refer to TC PipeLines or the Partnership. The general partner of the Partnership is TC PipeLines GP, Inc., a wholly-owned subsidiary of TransCanada.

We own a 46.45 per cent general partner interest in Great Lakes, which we acquired on February 22, 2007 from El Paso Corporation. The remaining 53.55 per cent general partner interest in Great Lakes is held by TransCanada.

We own a 50 per cent general partner interest in Northern Border, including a 20 per cent interest acquired on April 6, 2006. The remaining 50 per cent general partner interest in Northern Border is held by ONEOK Partners, a publicly traded limited partnership that is controlled by ONEOK, Inc.

We also own 100 per cent of Tuscarora. The Partnership acquired a 49 per cent interest from a wholly-owned subsidiary of TransCanada in September 2000. An additional 49 per cent was acquired from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, on December 19, 2006. On December 31, 2007, the Partnership acquired the remaining two per cent general partner interest in Tuscarora, with one per cent purchased from a wholly-owned subsidiary of TransCanada and the other one per cent purchased from Tuscarora Gas Pipeline Co.

The Partnership s general partner interests in Great Lakes, Northern Border and Tuscarora represent its only material assets at December 31, 2007. As a result, the Partnership is dependent upon Great Lakes, Northern Border and Tuscarora for all of its available cash.

Great Lakes Overview

Great Lakes is a Delaware limited partnership formed in 1990. Great Lakes operating revenue is derived from transportation of natural gas. Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba and extends across Minnesota, Northern Wisconsin and Michigan, and redelivers gas to TransCanada at the Canadian border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

Northern Border Overview

Northern Border is a Texas general partnership formed in 1978. Northern Border s operating revenue is derived from transportation of natural gas. Northern Border transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana and synthetic gas produced at the Dakota Gasification plant in North Dakota.

Tuscarora Overview

Tuscarora is a Nevada general partnership formed in 1993. Tuscarora s operating revenue is derived from transportation of natural gas. Tuscarora s U.S. interstate pipeline system originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs Southeast through Northeastern California and Northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power Company (Sierra Pacific Power), a subsidiary of Sierra Pacific Resources.

FACTORS THAT IMPACT OUR BUSINESS

Key factors that impact our business are the ability of Great Lakes and Northern Border to make distributions to us and of Tuscarora to generate positive operating cash flows and our ability to maintain a strong and balanced financial position. Partnership cash flows from our investments are necessary to generate sufficient cash to make distributions to our unitholders. A strong and balanced financial position will ensure that we are able to maintain a prudent level of available cash to make distributions to our unitholders.

FACTORS THAT IMPACT THE BUSINESS OF OUR PIPELINE SYSTEMS

Key factors that impact the business of our pipeline systems are the supply of and demand for natural gas in the markets in which our pipeline systems operate; the customers of our pipeline systems and the mix of services they require; competition; and government regulation of natural gas pipelines. These factors are discussed in more detail below.

Supply and Demand of Natural Gas

Our pipeline systems depend upon the continued availability of natural gas production and reserves in the regions we access, primarily the WCSB. Our pipeline systems provide their customers with natural gas transportation services to market demand areas. The amount of WCSB natural gas available for export is dependent upon natural gas production levels, demand for natural gas in Canada, and storage capacity for Canadian natural gas and demand for storage injection. Additional Canadian natural gas supply sources may be available in the future if new pipeline projects associated with the Mackenzie Delta in Northern Canada and the North Slope of Alaska are constructed.

Demand for natural gas transportation service on our pipeline systems is directly related to demand for natural gas in the markets served by these systems. Factors which may impact the overall demand for natural gas include weather conditions, economic conditions, government regulation, availability and price of alternative energy sources, fuel conservation measures, and technological advances in fuel economy and energy generation devices. Additionally, factors that may impact demand for transportation service on any one system include the ability and willingness of natural gas shippers to utilize one system over alternative pipelines, transportation rates, and the volume of natural gas delivered to markets from other supply sources and storage facilities.

Our pipeline systems depend upon the WCSB for the majority of the natural gas that they transport. There has been a decline in the flows out of WCSB over the last year. However, as discussed above, the impact of this decline on any given pipeline is dependent upon market conditions in the markets those pipelines serve. The decline in WCSB gas available for export did not negatively impact throughput on our pipeline systems in 2007. We cannot predict the impact of any export declines on 2008 throughput which will depend on WCSB natural gas available for export in the future and market conditions in the markets our pipeline systems serve.

The 2006-2007 winter was unusually warm in the markets served by Great Lakes. The low winter demand drove gas prices in the WCSB down and made it attractive to source gas in the supply area and move it to market instead of drawing storage gas. This increased utilization on the Great Lakes pipeline system. It also left Midwest storage levels at record highs, but in the post-Katrina environment when markets were disrupted by the hurricane, Great Lakes had sold its 2007 summer (and some winter 2006-2007) capacity on a firm basis so revenues were not adversely affected by lower than normal storage injection. Finally, with storage inventories at or near maximum, system demand was maintained late in the year by aggressively discounting to move available supply to markets.

Increased drilling and production activity in the Powder River Basin of Wyoming and Montana and the Williston Basin of Montana and North Dakota may present opportunities for Northern Border to pursue additional connections with this supply area. Future opportunities for potential additional supply include the construction of proposed coal gasificiation plants. A proposed coal gasification plant in North Dakota by Great Northern Power Development LP and Allied Syngas Corporation may also be a potential future supply source for Northern Border.

The GTN system is one of the U.S. transporters of Canadian natural gas from the WCSB, effectively the sole source of gas on Tuscarora. Tuscarora serves a number of markets along its route through Southern Oregon, Northern California and Northern Nevada. However, Tuscarora s largest customers are in the Reno-Sparks area of Washoe County, Storey County and downstream of the Paiute system, where gas consumption related to industrial use, population growth and increased gas-fired power generation has grown significantly and is expected to continue.

Customers

Our pipeline systems transport natural gas for a variety of customers including other natural gas pipelines, natural gas distribution companies, electric generation companies, natural gas producers, and natural gas marketing and trading companies. Each type of customer has a different reason for using certain natural gas transportation services and routes. Natural gas distribution companies and electric generation companies typically require a secure and reliable supply of natural gas over a sustained period of time to meet the needs of their customers. These types of customers typically enter into long-term firm transportation contracts to ensure a ready supply of natural gas and sufficient transportation capacity over the life of their contracts. Natural gas producers typically enter into firm transportation contracts to ensure that they will have sufficient capacity to deliver their product to market centers. Natural gas marketing and trading companies typically use transportation services to capitalize on natural gas price volatility.

Competition

Our pipeline systems compete primarily with other interstate and intrastate pipelines in the transportation of natural gas. Additionally, supply competition from other natural gas sources can impact demand for transportation on our pipeline systems. Growth in supplies available from other natural gas producing regions can impact prices for natural gas delivered to some of the markets our pipeline systems serve relative to other market regions. An increase in the number of new pipeline projects in the U.S. has led to rising costs, both labor and materials, associated with new pipeline projects. These rising costs may impact our pipeline systems ability to pursue expansion projects.

Great Lakes competes directly with Northern Border, Alliance/Vector, Viking and the TransCanada Mainline. In addition, supply competition from other natural gas sources can impact demand for transportation on Great Lakes. Great Lakes anticipates that further growth in supplies from the Rocky Mountain region will create additional supply in the markets Great Lakes serves. Anticipated additional supplies from the Eastern segment of the Rockies Express Pipeline, discussed below, may provide opportunities for Great Lakes to market its Eastern zone capacity for storage injection and withdrawal, which has historically gone underutilized.

Northern Border serves natural gas markets in the Midwestern U.S. through major interconnects with other interstate natural gas pipelines. Northern Border also delivers natural gas directly to LDCs in Iowa, Illinois and Indiana. Two of Northern Border s major interconnections are with Northern Natural Gas at Ventura, Iowa and Natural Gas Pipeline at Harper, Iowa. Northern Border provides its customers with access to the Chicago market area, which is the third largest market area hub in North America. Supply competition from other natural gas sources in these markets can adversely impact demand for transportation on Northern Border s system. Northern Border has seen growth in supplies from the Rocky Mountain region creating additional supply in the markets Northern Border serves, including Ventura, Harper and Chicago. Additional supply competition deliveries from other supply sources may impact Northern Border s ability to contract available capacity at Ventura and Harper beginning in April 2008 when approximately 37 per cent of its design capacity becomes uncontracted. Additional supply in the Chicago market may impact Northern Border s ability to contract available capacity in 2009 as long-term transportation contracts expire.

The Western segment of the Rockies Express Pipeline is increasing supply competition in Midwestern markets and could cause Northern Border to discount their rates or otherwise experience a reduction in their revenues. The Eastern segment of the Rockies Express Pipeline, from Missouri to Ohio, is expected to be placed in service by June 2009 (pending regulatory approvals), and is anticipated to transport natural gas further east, potentially mitigating excess supply in Northern Border s market region.

There are several other pipeline projects that have been announced, mostly moving gas from the U.S. Rocky Mountain Region to various regions of the U.S. Should any of these projects be built, they will have an impact on the U.S. natural gas markets, including the markets served by Northern Border and Great Lakes.

Tuscarora maintains a very strong competitive position relative to other sources of gas in the markets it serves. Tuscarora is one of only two pipelines that serves the Northern Nevada market, the other being Paiute Pipeline. Tuscarora can economically expand to meet the future gas transportation needs of the region by adding additional compression, which offers the greatest volume and pressure flexibility. Tuscarora also has access to supply regions as its upstream pipelines have excess capacity.

Government Regulation

Natural gas transportation is regulated by the FERC and other federal and state regulatory agencies, including the Department of Transportation. FERC regulatory policies govern the rates that pipelines are permitted to charge customers for interstate transportation of natural gas. The operation and maintenance of our pipeline systems are also impacted by the federal and state regulatory agencies.

The FERC-approved rate designs used by our pipeline systems are based upon firm service and interruptible services. Customers with firm service transportation agreements pay a fee known as a reservation charge to reserve pipeline capacity, regardless of use, for the term of their contracts. Firm service transportation customers may also pay a variable fee that is based on the distance and volume of natural gas they transport. Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed a variable fee based on distance and the volume of natural gas they transport. The majority of our pipeline systems revenue is generated by firm service transportation agreements.

HOW WE EVALUATE OUR OPERATIONS

We evaluate our business primarily on the basis of the underlying operating results for each of our pipeline systems, along with a measure of Partnership cash flows. Partnership cash flows, a non-generally accepted accounting principle (GAAP) financial measure, is the sum of cash distributions received from Northern Border and Great Lakes, and cash flows from Tuscarora s operating activities less Partnership costs.

RESULTS OF OPERATIONS OF TC PIPELINES, LP

The general partner interests in Great Lakes, Northern Border and Tuscarora were our only material sources of income in 2007; therefore, our results of operations were influenced by and reflect the same factors that influenced the financial results of Great Lakes, Northern Border and Tuscarora. See Item 1. Business .

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions, with respect to values or conditions which cannot be known with certainty, that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates. The following summarizes the Partnership s and our pipeline systems accounting policies and estimates, which should be read in conjunction with Note 2 of the Partnership s Financial Statements included elsewhere in this report.

We account for our investments in Great Lakes and Northern Border using the equity method of accounting. The equity method of accounting is appropriate where the investor does not control an investee, but rather is able to exercise significant influence over the operating and financial policies of an investee. We are able to exercise significant influence over our investments in Great Lakes and Northern Border because of our ownership interests and our representation on the Great Lakes and Northern Border management committees.

We used the equity method to account for our investment in Tuscarora until December 19, 2006. On this date, we acquired an additional 49 per cent general partner interest in Tuscarora and, as a result of acquiring a controlling interest in Tuscarora, began to consolidate its operations. The consolidation method of accounting is appropriate where the investor controls the investee.

Regulatory Assets

Our pipeline systems accounting policies conform to Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. Our pipeline systems consider several factors to evaluate their continued application of the provisions of SFAS No. 71 such as potential deregulation of their pipelines; anticipated changes from cost-based ratemaking to another form of regulation; increasing competition that limits their ability to recover costs; and regulatory actions that limit rate relief to a level insufficient to recover costs.

Certain assets that result from the ratemaking process are reflected on Northern Border s balance sheet as regulatory assets. If Northern Border determines future recovery of these assets is no longer probable as a result of discontinuing application of SFAS No. 71 or other regulatory actions, Northern Border would be required to write off the regulatory assets at that time. As of December 31, 2007, Northern Border reflected regulatory assets of $20.6 million on its balance sheet. These assets are being amortized as directed by the FERC in Northern Border s previous regulatory proceedings over varying time periods up to 43 years.

As at December 31, 2007, Great Lakes and Tuscarora did not have any regulatory assets or liabilities recorded on their respective balance sheets.

Contingencies

Our pipeline systems accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. Our pipeline systems accrue for these contingencies when their assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with SFAS No. 5, Accounting for Contingencies. Our pipeline systems base their estimates on currently available facts and their estimates of the ultimate outcome or resolution. Actual results may differ from our pipeline systems estimates resulting in an impact, positive or negative, on earnings.

Impairment of Long-Lived Assets and Goodwill

We assess our long-lived assets for impairment based on SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

We assess our goodwill for impairment at least annually, based on SFAS No. 142, *Goodwill and Other Intangible Assets.* An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with SFAS No. 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. At December 31, 2007, we had $81.7 million of goodwill recorded on our balance sheet related to the Tuscarora acquisitions.

Impact of New Accounting Standards

In 2006, the Financial Accounting Standards Board issued SFAS No. 157, *Fair Value Measurements,* and during 2007, issued SFAS No. 141(R), *Business Combinations - revised*, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115*, and SFAS No. 160, *Noncontrolling Interests in Consolidated financial Statements*.

SFAS No. 157 establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. The effect of adopting SFAS No. 157 is not expected to be material to our results of operations or financial position.

SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*. SFAS No. 141 (R) retains the fundamental requirements of SFAS No. 141 that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination, with the objective of improving the relevance and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. The requirements of this standard will not have a material impact on the results of the Partnership.

SFAS No. 159 permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. The effect of adopting SFAS No. 159 is not expected to be material to our results of operations or financial position.

SFAS No. 160 clarifies the classification of noncontrolling interests in consolidated statements of financial position and the accounting for and reporting of transactions between the reporting entity and holders of such noncontrolling interests. The Partnership does not have noncontrolling interests and therefore, is not affected by the changes resulting from this standard.

In June 2007 the Emerging Issues Task Force of the FASB issued EITF 07-4, Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share,* to Master Limited Partnerships . EITF 07-4 addresses how current period earnings of a Master Limited Partnership (MLP) should be allocated to the general partner, limited partners and when applicable, incentive distribution rights when applying the two-class method under Statement 128. A tentative conclusion was ratified by the FASB in December 2007. We are currently reviewing the applicability of EIFT 07-4 to our results of operations and financial position.

YEAR IN REVIEW

TC PipeLines

Acquisition of Interest in Great Lakes

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation (El Paso). TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent general partner interest simultaneously with the Partnership s acquisition of its interest. In connection with these transactions, a wholly-owned subsidiary of TransCanada became the operator of Great Lakes.

Equity Issuance

On February 22, 2007, the Partnership completed a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million which closed concurrently with the Great Lakes acquisition. TransCan Northern purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

Acquisition of Remaining Interest in Tuscarora

On December 31, 2007, TC PipeLines acquired the remaining two per cent general partner interest in Tuscarora, with one per cent purchased from a wholly-owned subsidiary of TransCanada and the other one per cent purchased from Tuscarora Gas Pipeline Co. TC PipeLines now owns 100 per cent of Tuscarora.

Great Lakes

Operating Revenues

For the period of March 1, 2007 to December 31, 2007, Great Lakes average contracted capacity was 104 per cent. As of January 31, 2008, the weighted average remaining life of Great Lakes contracts was 2.4 years.

Operating Data	For the period February 23 to December 31, 2007
MMcf delivered	**693,017**
MMcf/d average throughput	**2,221**

Regulatory Deferred Income Taxes

Income taxes are the responsibility of the partners and are not reflected in Great Lakes financial statements prepared in accordance with GAAP. On the balance sheet prepared for regulatory accounting purposes, partners capital is reduced by the amount equivalent to accumulated deferred income taxes.

The sale of El Paso s partnership interest, and a corresponding Internal Revenue Code Section 754 election, resulted in Great Lakes pre-acquisition amounts equivalent to net deferred income tax liability balances being reduced by 46.45 per cent. In addition, Great Lakes amounts equivalent to net deferred tax liabilities for pre-acquisition retirement plans were eliminated. Great Lakes regulated partners capital and amounts equivalent to net deferred tax liabilities were adjusted on February 22, 2007, by approximately $135 million as approved by the FERC.

Michigan Business Tax

In the third quarter of 2007, the state of Michigan enacted the Michigan Business Tax (MBT), which replaced the Michigan Single Business Tax (SBT), effective January 1, 2008. The MBT is an income tax levied at the partnership level. The MBT is expected to result in an annual income tax expense of approximately $4 to $5 million and to provide a property tax credit of approximately $1 million, for a net annual impact of $3 to $4 million to Great Lakes beginning in 2008. In September 2007, Great Lakes eliminated its deferred SBT amounts consistent with the elimination of the SBT tax. This resulted in an increase of $1.6 million to Great Lakes net income.

Northern Border

Operating Revenues

Long-term rates were reduced and short-term seasonal rates were implemented effective January 1, 2007 as a result of Northern Border s rate case settlement, discussed later in this section. 2007 revenues were comparable to 2006 primarily due to the implementation of seasonal rates and a favorable contracting experience for 2007. Northern Border s average throughput and contracted capacity remained consistent from 2007 to 2006 as shown in the table below. The trend toward shorter term contracts and discounted transportation rates continued on Northern Border s system. The weighted average life of Northern Border s contracts declined from 1.8 years at December 31, 2006 to 1.3 years at January 31, 2008.

Operating Data	2007	2006
MMcf delivered	**799,637**	799,301
MMcf/d average throughput	**2,247**	2,246
Average contracted capacity	**97**%	97%

Settlement of Rate Case

The settlement of Northern Border s 2005 rate case was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border s system. Beginning January 1, 2007, overall rates were reduced, compared with rates prior to the filing, by approximately five per cent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dth is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge rate. The factors used in calculating depreciation expense for transmission plant were increased from 2.25 per cent to 2.40 per cent. The settlement also provided for seasonal rates for short-term transportation services. Seasonal maximum rates vary on a monthly basis from approximately $0.54 per Dth to approximately $0.29 per Dth for the full transportation route from Port of Morgan, Montana to the Chicago area.

Change in Operator

TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became Northern Border s operator effective April 1, 2007 under a new operating agreement.

Tuscarora

Operating Revenues

Long-term rates were reduced effective June 1, 2006 as a result of Tuscarora s rate settlement, discussed later in this section. 2007 revenues were lower when compared to 2006 primarily due to the reduction of rates effective June 1, 2006. Tuscarora s average throughput and contracted capacity remained consistent from 2007 to 2006 as shown in the table below. The weighted average remaining life of Tuscarora s contracts declined from 11.4 years at December 31, 2006 to 10.4 years at December 31, 2007.

Operating Data	**2007**	**2006**
MMcf delivered	**28,257**	28,067
MMcf/d average throughput	**77**	77
Average contracted capacity	**96**%	96%

Cost and Revenue Study

On August 7, 2006, the FERC approved a settlement reached by Tuscarora, the PUCN and Sierra Pacific Power that resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) effective June 1, 2006. This was a 17 per cent reduction to the previous rate of $0.4811/dth-day, or an approximate $5 million reduction in Tuscarora s annual revenues. In addition, the settlement resulted in a moratorium on all rate actions before the FERC by any party to the settlement for a period of 48 months to May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate.

2008 Expansion Project

Tuscarora filed an application with the FERC on November 20, 2006 for approval to construct the compressor station and related facilities (Tuscarora 2008 Expansion Project). This project is to transport a maximum of 39 MMcf/d to Sierra Pacific Power to supply its Tracy combined cycle power plant. The project is expected to cost approximately $20 million which will be recovered from rates charged to Sierra Pacific Power under the Transportation Service Agreement (TSA) signed with Sierra Pacific Power. The TSA is for a period of 22.5 years from the commencement date.

The FERC issued a Certificate of Public Convenience and Necessity for Tuscarora s 2008 Expansion Project on July 24, 2007 in response to Tuscarora s November 2006 application for approval to construct the compressor station and related facilities. The expansion is currently expected to go into service in March of 2008.

Net Income

To supplement our financial statements we have presented a comparison of the earnings contribution components from each of our investments. We have presented net income in this format in order to enhance investors understanding of the way management analyzes the Partnership s financial performance. We believe this summary provides a more meaningful comparison of the Partnership s net income to prior years, as we account for our partially owned pipeline systems using the equity method. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

The shaded areas in the tables below disclose the results from Great Lakes, Northern Border and Tuscarora, representing 100 per cent of each entity s operations for the given period.

2007 (millions of dollars)	**Partnership**	**Tuscarora(1)**	**Corporate**	**Great Lakes(2) Feb 23 - Dec 31**	**Northern Border(3)**
Transmission revenues	**27.2**	27.2		236.2	309.4
Operating expenses	**(8.3)**	(4.9)	(3.4)	(53.7)	(83.5)
	18.9	22.3	(3.4)	182.5	225.9
Depreciation	**(6.3)**	(6.3)		(49.4)	(60.7)
Financial charges, net and other	**(33.8)**	(4.4)	(29.4)	(27.6)	(41.1)
				105.5	124.1
Equity income	**110.2**			49.0	61.2
Net income	**89.0**	11.6	(32.8)	49.0	61.2

(1) TC PipeLines owns a 100 per cent general partner interest in Tuscarora following the acqusition of an additional two per cent interest on December 31, 2007.

(2) TC PipeLines acquired a 46.45 per cent general partner interest in Great Lakes on February 22, 2007.

(3) TC PipeLines owns a 50 per cent general partner interest in Northern Border. Equity income from Northern Border includes amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the additional 20 per cent acquisition in April 2006.

2006 (millions of dollars)	**Partnership**	**Tuscarora(4) Dec 20 - Dec 31**	**Corporate**	**Tuscarora(4) Jan 1 - Dec 19**	**Northern Border(5)**
Transmission revenues	**0.9**	0.9		28.6	310.9
Operating expenses	**(2.7)**	(0.1)	(2.6)	(4.6)	(81.0)
	(1.8)	0.8	(2.6)	24.0	229.9
Depreciation	**(0.2)**	(0.2)		(6.0)	(58.7)
Financial charges, net and other	**(15.8)**	(0.2)	(15.6)	(5.1)	(41.3)
				12.9	129.9
Equity income	**62.5**			5.9	56.6
Net income	**44.7**	0.4	(18.2)	5.9	56.6

[(4)] With the acquisition of an additional 49 per cent general partner interest in Tuscarora on December 19, 2006, TC PipeLines changed its method of accounting for this investment from equity accounting to consolidation.

[(5)] Equity income from TC PipeLines investment in Northern Border was based upon its 30 per cent ownership to April 5, 2006 and 50 per cent ownership following the acquisition of an additional 20 per cent general partner interest on April 6, 2006. Equity income from Northern Border includes amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the acquisition.

2005 (millions of dollars)	**Partnership**	**Corporate**	**Tuscarora(6)**	**Northern Border(7)**
Transmission revenues			32.3	321.7
Operating expenses	**(2.0)**	(2.0)	(4.4)	(70.8)
	(2.0)	(2.0)	27.9	250.9
Depreciation			(6.2)	(58.1)
Financial charges, net and other	**(1.0)**	(1.0)	(5.6)	(40.5)
			16.1	152.3
Equity income	**53.2**		7.5	45.7
Net income	**50.2**	(3.0)	7.5	45.7

[(6)] TC PipeLines owned a 49 per cent general partner interest in Tuscarora. Equity income from Tuscarora includes an acquisition allocation amortization related to the initial purchase of the Partnership s general partner interest in Tuscarora.

[(7)] TC PipeLines owned a 30 per cent general partner interest in Northern Border.

Year Ended December 31, 2007 Compared with the Year Ended December 31, 2006

Net income increased $44.3 million, or 99 per cent, to $89.0 million in 2007, compared to $44.7 million in 2006. This increase was due primarily to acquisition activities in 2007 and 2006. Equity income in 2007 included $49.0 million from our investment in Great Lakes, which we acquired on February 22, 2007. The Partnership s earnings increased $4.6 million in 2007 as a result of its ownership interest in Northern Border. Of this increase, $7.1 million is due to the additional 20 per cent general partner interest in Northern Border acquired on April 6, 2006, offset by a $2.5 million decrease due to a reduction in Northern Border s net income. The Partnership s earnings increased $5.1 million in 2007 as a result of its ownership interest in Tuscarora. Tuscarora contributed $11.4 million to the Partnership s earnings in 2007, including a $0.2 million non-controlling interest recorded by the Partnership. The Partnership s earnings increased by $6.0 million due to the additional 49 per cent general partner interest in Tuscarora acquired on December 19, 2006, offset by a $0.9 million decrease due to a reduction in Tuscarora s net income. The increase in the Partnership s earnings as a result of acquisitions is partially offset by a $13.8 million increase in the Partnership s financing costs.

Great Lakes net income for the period from acquisition to December 31, 2007 was $105.5 million, in line with our expectations. The Partnership completed the acquisition of Great Lakes on February 22, 2007 and included 46.45 per cent of its earnings from this date. Great Lakes revenues are primarily derived from its interstate natural gas transmission service. In 2007, approximately 91 per cent of Great Lakes transportation revenues was derived from long-term firm service contracts.

Northern Border s net income decreased $5.8 million, or four per cent, to $124.1 million in 2007 compared to $129.9 million in 2006. Slight increases in depreciation and operating expenses, along with a small reduction in transmission revenues contributed to the decrease in net income. Depreciation expense increased by $2.0 million over the prior year primarily due to the change in depreciation rates effective January 1, 2007 as a result of the 2005 rate case settlement. Operating expenses increased $2.5 million over the prior year primarily due to a $2.3 million transition related charge in 2007 related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used to support Northern Border s operations. Increases in electric compression charges due to increased usage and electric rates were mostly offset by decreased taxes other than income. Excluding the positive impact of the higher ownership interest, the $5.8 million decrease in Northern Border s net income resulted in a $2.5 million decrease to the Partnership s net income.

Tuscarora s net income decreased $1.7 million, or 13 per cent, to $11.6 million in 2007. This decrease was mainly due to a full year impact of the settlement transportation rates that went into effect on June 1, 2006. The decrease in Tuscarora s net income contributed to a $0.9 million decrease to the Partnership s net income.

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Net income decreased $5.5 million, or 11 per cent, to $44.7 million in 2006, compared to $50.2 million in 2005. Net income of Northern Border and Tuscarora decreased in 2006 when compared to 2005 which contributed to an $8.1 million decrease in Partnership s earnings; however, this decrease was partially offset by an increased earnings contribution resulting from the 2006 acquisitions net of financing charges. The Partnership s earnings increased $17.6 million and $0.2 million in 2006 due to the acquisition of the additional 20 per cent interest in Northern Border and the additional 49 per cent general interest in Tuscarora, respectively. An increased outstanding debt balance resulted in increased financial charges of $14.8 million that partially offset the increases in earnings as a result of acquisitions.

Northern Border s net income decreased $22.4 million to $129.9 million in 2006, compared to $152.3 million in 2005. A one-time revenue amount related to the sale of the bankruptcy claims held against Enron by Northern Border in 2005 contributed $9.4 million to Northern Border s 2005 revenues. Decreased firm demand revenue and commodity charges were partially offset by additional revenue from transportation contracts related to the Chicago III Expansion Project. Increased operating expenses due to increased general and administrative expenses and electric compression charges associated with the Chicago III Expansion Project contributed $10.2 million to the decrease in net income at Northern Border. The $22.4 million decrease in Northern Border s net income contributed to a $6.7 million decrease to the Partnership s net income.

Tuscarora s net income decreased $2.8 million to $13.3 million in 2006, compared to $16.1 million in 2005, primarily due to lower net revenues resulting from settlement transportation rates that went into effect on June 1, 2006. The decrease in Tuscarora s net income contributed to a $1.4 million decrease to the Partnership s net income.

Partnership Cash Flows

To supplement our financial statements, we disclose Partnership cash flows . We have presented this additional information to enhance investors understanding of the way that management analyzes the Partnership s financial performance. We believe this summary provides a more meaningful comparison of the Partnership s financial performance to prior years, as Partnership cash flows fund the cash distributions that the Partnership pays to its unitholders. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

(millions of dollars except per common unit amounts)		**2007**		**2006**		**2005**
Total cash distributions received(a)		**147.6**		88.1		69.2
Cash flows from Tuscarora s operating activities(b)		**19.9**				
Partnership costs(c)		**(32.8)**		(18.2)		(3.0)
Partnership cash flows(c)		**134.7**		69.9		66.2
Partnership cash flows per common unit	**$**	**4.17**	$	3.99	$	3.78
Cash distributions paid		**86.7**		43.5		43.0
Cash distributions paid per common unit	**$**	**2.565**	$	2.325	$	2.300

[a] Reconciliation of non-GAAP financial measure: Total cash distributions received is a non-GAAP financial measure which is the sum of equity income from investment in Great Lakes, return of capital from Great Lakes, equity income from investment in Northern Border, return of capital from Northern Border and up until December 19, 2006, equity income from investment in Tuscarora and return of capital from Tuscarora. It is provided as a supplement to results reported in accordance with GAAP. Management believes that this is a meaningful measure to assist investors in evaluating the levels of cash distributions from the Partnership s investments. Below is a reconciliation of total cash distributions received to GAAP financial measures:

(millions of dollars)	2007	2006	2005
Equity income from investment in Great Lakes	**49.0**		
Return of capital from Great Lakes	**12.3**		
Cash distributions from Great Lakes	**61.3**		
Equity income from investment in Northern Border	**61.2**	56.6	45.7
Return of capital from Northern Border	**25.1**	23.8	15.2
Cash distributions from Northern Border	**86.3**	80.4	60.9
Equity income from investment in Tuscarora		5.9	7.5
Return of capital from Tuscarora		1.8	0.8
Cash distributions from Tuscarora		7.7	8.3
Total cash distributions received	**147.6**	88.1	69.2

(b) Refer to Note 5 of the Partnership s financial statements for cash flows from Tuscarora s operating activities for the year ended December 31, 2007. TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006 and began consolidating Tuscarora s operations upon acquisition of an additional 49 per cent general partner interest. Cash flows from Tuscarora s operating activities for 2006 have not been included in the above analysis as the Partnership effectively accounted for Tuscarora on a consolidated basis for only the last 11 days of the year.

(c) Reconciliation of non-GAAP financial measure: Partnership cash flows is a non-GAAP financial measure which is the sum of cash distributions received and cash flows from Tuscarora s operating activities less Partnership costs. We exclude Tuscarora s costs from the Partnership costs so that investors may evaluate our costs independent of costs directly attributable to our investments. Management believes that this is a useful measure to assist investors in evaluating the Partnership s cash flow from its operating activities. A reconciliation of Partnership costs is summarized below:

(millions of dollars)	2007	2006	2005
Operating expenses	**8.3**	2.7	2.0
Financial charges, net and other	**33.8**	15.8	1.0
Less:			
Operating expenses and financial charges from Tuscarora	**(9.3)**	(0.3)	
Partnership costs	**32.8**	18.2	3.0

Year Ended December 31, 2007 Compared with the Year Ended December 31, 2006

Partnership cash flows increased $64.8 million, or 93 per cent, to $134.7 million in 2007, compared to $69.9 million in 2006. This increase was primarily a result of cash flows received from acquisitions made in 2007 and 2006. Partnership cash flows in 2007 included cash distributions received of $61.3 million resulting from the acquisition of Great Lakes. Cash distributions received from Northern Border increased $5.9 million in 2007 compared to the prior year due primarily to the additional 20 per cent interest in Northern Border. The Partnership began consolidating Tuscarora s operations on December 19, 2006, when it acquired a controlling interest in Tuscarora. Cash flows from Tuscarora s operating activities in 2007 were $19.9 million, while the distributions received from Tuscarora in 2006 were $7.7 million. Partnership costs increased $14.6 million to $32.8 million, compared to $18.2 million in 2006 primarily due to increased financial charges related to higher outstanding debt balances.

Excluding the returns of capital from our investments, the Partnership used $758.8 million of cash flows for investing activities in 2007 compared to $407.6 million used in 2006. In 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation for $733.4 million in cash. In 2006, the Partnership incurred costs of $308.0 million to acquire an additional 20 per cent interest in Northern Border and $97.2 million related to its acquisition of the additional 49 per cent interest in Tuscarora. The Partnership made equity contributions of $7.5 million to Northern Border in 2007, compared to $3.1 million made in 2006. Tuscarora made capital expenditures of $13.2 million in 2007, of which $12.2 million related to the compressor station expansion project in Likely, California.

The Partnership generated $625.6 million of net cash flows from financing activities in 2007 compared to $337.6 million in 2006. The acquisition of a 46.45 per cent general partner interest in Great Lakes was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with this transaction. The Partnership incurred $1.2 million of costs associated with the amended senior credit facility. The Partnership incurred debt of $171.5 million in 2007, which included $126.0 million in connection with the Great Lakes acquisition. The Partnership repaid $66.2 million of the outstanding balance on its senior credit facility and senior notes throughout the year.

Distributions paid by the Partnership increased $43.2 million, or 99 per cent, to $86.7 million in 2007 compared to $43.5 million in 2006 due to the increased number of common units outstanding and increases in quarterly per common unit distribution amounts declared in each of the last three quarters of 2007. In 2007, the Partnership paid the $86.7 million in distributions in the following manner: $79.0 million to common unitholders (including $5.2 million to the general partner as holder of 2,035,106 common units and $17.1 million to a TransCan Northern as holder of 8,678,045 common units), $5.9 million to the general partner as holder of the incentive distribution rights, and $1.8 million to the general partner in respect of its two per cent general partner interest.

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Partnership cash flows increased $3.7 million, or 6 per cent, to $69.9 million in 2006, compared to $66.2 million in 2005. Cash distributions received from Northern Border increased $19.5 million in 2006 compared to 2005. The additional 20 per cent ownership interest in Northern Border resulted in an additional $26.7 million in distributions received partially offset by a $7.2 million reduction in distributions attributable to the Partnerships original 30 per cent interest in Northern Border. The Partnership s cash flows were also impacted by an increase in Partnership financial charges of $14.6 million due to the higher outstanding debt balance. Distributions made by Northern Border were higher in 2005 mainly due to higher revenues and $9.4 million realized on the sale of its unsecured bankruptcy claims held against Enron.

Excluding the returns of capital from our investments, the Partnership used $407.6 million of cash flows for investing activities in 2006 compared to $0.3 million used in 2005. In 2006, the Partnership incurred costs of $308.0 million to acquire an additional 20 per cent interest in Northern Border, and in addition, made equity contributions of $3.1 million which were used by Northern Border to repay indebtedness. The Partnership made a $0.3 million contribution to Tuscarora in 2005 related to construction of the Barrick Lateral.

The Partnership generated $337.6 million of cash flows from financing activities in 2006 compared to $66.0 million in cash flows used for financing activities in 2005. The increase in financing was to support the acquisition activities in 2006. To finance the 2006 acquisitions, the Partnership borrowed a net $383.5 million from bridge, term and revolving credit facilities. Tuscarora repaid $2.4 million of the outstanding balance on its senior secured notes in December 2006.

Distributions paid increased $0.5 million to $43.5 million in 2006 compared to $43.0 million in 2005. The increase was due to an increase in the Partnership s quarterly cash distribution from $0.575 per common unit to $0.60 per common unit beginning in the fourth quarter of 2006.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES, LP

Overview

Our principal sources of liquidity include distributions received from our investments in Great Lakes and Northern Border, operating cash flow from Tuscarora and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

Summary of the Partnership s Contractual Obligations

The Partnership s contractual obligations as of December 31, 2007 included the following:

		Payments Due by Period			
(millions of dollars)	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
Senior Credit Facility due 2011	507.0			507.0	
Series A Senior Notes due 2010	54.5	3.3	51.2		
Series B Senior Notes due 2010	5.5	0.5	5.0		
Series C Senior Notes due 2012	6.4	0.8	1.7	3.9	
Interest payments on Senior Credit Facility (a)	102.5	25.1	50.6	26.8	
Interest payments on Senior Notes	13.4	4.7	8.4	0.3	
Operating leases	0.1	0.1			
Capital commitments (b)	3.0	3.0			
	692.4	37.5	116.9	538.0	

(a) Interest payments on Senior Credit Facility include the hedging effect of the derivative financial instruments placed on $475 million of the outstanding debt.

(b) Capital commitments relate to the Likely Compressor Station construction.

The Partnership s Debt and Credit Facilities

On March 31, 2006, the Partnership entered into an unsecured credit agreement for a $310.0 million credit facility (Bridge Loan Credit Facility) with a banking syndicate. Borrowings under the Bridge Loan Credit Facility bore interest, at the option of the Partnership, at the LIBOR or the base rate plus an applicable margin. On April 5, 2006, the Partnership borrowed $307.0 million under the Bridge Loan Credit Facility to finance the acquisition of an additional 20 per cent general partner interest in Northern Border. The remaining $3.0 million commitment under the Bridge Loan Credit Facility was terminated. On December 12, 2006, the Bridge Loan Credit Facility was refinanced through a $297.0 million draw on a $410.0 million credit agreement (Senior Credit Facility) with a banking syndicate and the use of $10.0 million cash on hand. The interest rate on the Bridge Loan Credit Facility averaged 6.29 per cent for the year ended December 31, 2006.

On December 12, 2006, the Partnership entered into a credit agreement for the Senior Credit Facility. On December 19, 2006, TC PipeLines borrowed an additional $100.0 million under the Senior Credit Facility to finance the acquisition of an additional 49 per cent interest in Tuscarora.

On February 13, 2007, the Senior Credit Facility was amended and restated in connection with the Great Lakes acquisition. The amount available under the Senior Credit Facility increased from $410.0 million to $950.0 million, consisting of a $700.0 million senior term loan and a $250.0 million senior revolving credit facility, with $194.0 million of the senior term loan available being terminated upon closing of the Great Lakes acquisition. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. On November 29, 2007, $18.0 million of the senior term loan was repaid, and hence terminated, leaving $488.0 million available and outstanding under the senior term loan. At December 31, 2007, $19.0 million is outstanding under the senior revolving credit facility, leaving $231.0 million available for future borrowings.

The Senior Credit Facility matures on December 12, 2011, subject to two one-year extensions at the option of the Partnership and with the approval of a majority of the lenders thereunder. Amounts borrowed may be repaid in part or in full prior to that time without penalty. Borrowings under the Senior Credit Facility will bear interest based, at the Partnership s election, on the LIBOR or the prime rate plus, in either case, an applicable margin. There was $507.0 million outstanding under the Senior Credit Facility at December 31, 2007 (2006 - $397.0 million). The interest rate on the Senior Credit Facility averaged 6.01 per cent for the year ended December 31, 2007 (2006 6.16 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.75 per cent for the year ended December 31, 2007. Prior to hedging activities, the interest rate was 5.62 per cent at December 31, 2007 (2006 6.07 per cent).

The Senior Credit Facility requires the Partnership to maintain a leverage ratio (debt to adjusted cash flow) of not more than 4.75 to 1.00 at the end of any fiscal quarter. The permitted leverage ratio will increase to 5.50 to 1.00 for the first three fiscal reporting periods during any 12-month period immediately following the consummation of specified material acquisitions. At December 31, 2007, the Partnership was in compliance with all of its financial covenants.

In 1995, Tuscarora issued $91.7 million of 7.13 per cent senior secured notes, which mature on December 21, 2010 (Series A). In 2000, Tuscarora issued $8.0 million of 7.99 per cent senior secured notes, which mature on December 21, 2010 (Series B). In 2002, Tuscarora issued $10.0 million of 6.89 per cent senior secured notes, which mature on December 21, 2012 (Series C). Series C proceeds were used to finance the construction of Tuscarora s expansion facilities. The Series A, Series B and Series C notes (collectively, the Notes) have a final payment at maturity of $46.7 million, $4.1 million and $2.7 million, respectively. The Notes are secured by Tuscarora s transportation contracts, supporting agreements and substantially all of Tuscarora s property. The credit agreement for the Notes contains certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners. On December 31, 2007, $54.5 million, $5.5 million and $6.4 million were outstanding on the Series A, Series B and Series C Senior Notes, respectively. On December 31, 2006, $57.9 million, $6.0 million and $7.2 million were outstanding on the Series A, Series B and Series C Senior Notes, respectively.

Interest Rate Swaps and Options

The Partnership uses derivatives to assist in managing its exposure to interest rate risk. At December 31, 2007, the fair value of the interest rate swaps and options accounted for as hedges was negative $9.8 million (2006 - positive $1.6 million). The fair value of interest rate swaps and options have been calculated using year-end market rates. The notional amount hedged was $475 million. $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $100.0 million of variable-rate debt is hedged by an interest rate option during the period from May 22, 2007 through May 22, 2009 to an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid will be 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility.

Capital Requirements

In 2007, the Partnership made an equity contribution of $7.5 million to Northern Border, representing the Partnership s 50 per cent share of a $15.0 million cash call issued by Northern Border, which fulfilled the previously approved 2007 equity cash calls. The proceeds were used by Northern Border to repay indebtedness. In 2006, the Partnership made an equity contribution of $3.1 million, representing the Partnership s then 30 per cent share of a $10.3 million cash call issued by Northern Border, where the proceeds were used to fund a portion of the Chicago III Expansion Project capital costs.

In 2007, Tuscarora incurred $13.2 million of capital expenditures, of which $12.2 million related to its compressor station expansion in Likely, California. These capital expenditures were funded with operating cash flows. In 2005, the Partnership made an equity contribution of $0.3 million to Tuscarora, representing the Partnership s then 49 per cent share of a $0.7 million cash call issued by Tuscarora. Those proceeds were used to fund the construction of the Barrick Lateral that went into service June 2005.

To the extent the Partnership has any additional capital requirements with respect to our pipeline systems or makes acquisitions in 2008, we expect to fund these requirements with operating cash flows, debt and/or equity.

Cash Distribution Policy of TC PipeLines

The Partnership makes distributions of Available Cash, as defined in the Partnership Agreement, in the following manner:

- First, 98 per cent to the common units, pro rata, and two per cent to the general partner, until there is distributed for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and
- Thereafter, in a manner whereby the general partner has rights (referred to as incentive distribution rights) to receive increasing percentages of excess quarterly cash distributions over specified cash distribution thresholds calculated in the following manner:

- First, 85 per cent to all units, pro rata, and 15 per cent to the general partner, until each unitholder has received a total of $0.5275 for that quarter;
- Second, 75 per cent to all units, pro rata, and 25 per cent to the general partner, until each unitholder has received a total of $0.6900 for that quarter; and
- Third, 50 per cent to all units, pro rata, and 50 per cent to the general partner.

The distribution to the general partner described above, other than in its capacity as a holder of 2,035,106 common units that are in excess of its aggregate two per cent general partner interest, represent the incentive distribution rights.

2007 Fourth Quarter Cash Distribution

On January 17, 2008, the Board of Directors of the general partner declared the Partnership s 2007 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 14, 2008 to unitholders of record as of January 31, 2008, totaled $25.6 million and was paid in the following manner: $23.2 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $5.8 million to TransCan Northern as holder of 8,678,045 common units), $1.9 million to the general partner as holder of the incentive distribution rights, and $0.5 million to the general partner in respect of its two per cent general partner interest.

LIQUIDITY AND CAPITAL RESOURCES OF OUR PIPELINE SYSTEMS

Overview

Our pipeline systems principal source of liquidity is cash generated from operating activities and bank credit facilities. Our pipeline systems fund their operating expenses, debt service and cash distributions to partners primarily with operating cash flow.

Capital expenditures are funded by a variety of sources, including cash generated from operating activities, borrowings under bank credit facilities, issuance of senior notes or equity contributions from our pipeline systems partners. The ability of our pipeline systems to access capital markets for debt under reasonable terms depends on their financial condition, credit ratings and market conditions.

Our pipeline systems believe that their ability to obtain financing at reasonable rates and their history of consistent cash flow from operating activities provide a solid foundation to meet their future liquidity and capital resource requirements.

Summary of Great Lakes Contractual Obligations

Great Lakes contractual obligations related to debt as of December 31, 2007 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
8.74% series Senior Notes due 2008 to 2011	40.0	10.0	20.0	10.0	
9.09% series Senior Notes due 2012 to 2021	100.0			10.0	90.0
6.73% series Senior Notes due 2009 to 2018	90.0		18.0	18.0	54.0
6.95% series Senior Notes due 2019 to 2028	110.0				110.0
8.08% series Senior Notes due 2021 to 2030	100.0				100.0
Interest payments on debt	390.0	34.2	64.3	58.3	233.2
	830.0	44.2	102.3	96.3	587.2

Long-Term Financing

All of Great Lakes outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restricted covenants in the Senior Note Agreements, approximately $237.0 million of Great Lakes partners capital was restricted as to distributions as of December 31, 2007. In addition, Great Lakes is required to maintain a minimum consolidated tangible net worth of $175 million. At December 31, 2007, Great Lakes was in compliance with all of its financial covenants.

The aggregate estimated fair value of long-term debt was $525 million for 2007. The aggregate annual required repayments of senior notes are $10 million in 2008 and $19 million for each year 2009 through 2012. In 2007, interest expense related to Great Lakes senior notes was $35 million.

Summary of Northern Border s Contractual Obligations

Northern Border s contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2007, included the following:

(millions of dollars)	Total	Payments Due by Period Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
7.75% senior notes due 2009	200.0		200.0		
7.50% senior notes due 2021	250.0				250.0
$250 million credit agreement due 2012	166.0			166.0	
Interest payments on debt	321.3	43.1	65.6	49.3	163.3
Operating leases	72.1	2.5	4.7	3.8	61.1
Other long-term obligations	3.1	0.8	1.5	0.8	
	1,012.5	46.4	271.8	219.9	474.4

Operating Leases

Northern Border is required to make future minimum payments for office space and rights-of-way under non-cancelable operating leases.

Other

Northern Border is required to pay $3.6 million over a five year period under a transition services agreement between ONEOK Partners GP and TransCanada Northern Border, related to the reimbursement for shared assets acquired by ONEOK Partners. In 2007, a charge of $2.3 million was recorded in operations and maintenance expense and $1.3 million was recorded as plant, property and equipment.

Amended and Restated Credit Agreement

On April 27, 2007, Northern Border entered into a $250 million amended and restated revolving credit agreement (the 2007 Credit Agreement) with certain financial institutions. The 2007 Credit Agreement was used to refinance the outstanding indebtedness under Northern Border s $175 million revolving credit agreement dated as of May 16, 2005 and was used to repay all of the $150 million of its 6.25 per cent Senior Notes due May 1, 2007. The 2007 Credit Agreement can also be used to finance permitted acquisitions, pay related fees and expenses, issue letters of credit and provide for ongoing working capital needs and for other general business purposes, including capital expenditures.

Northern Border may, at its option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under its 2007 Credit Agreement by an aggregate amount not to exceed $100 million, provided that lenders are willing to commit additional amounts. At Northern Border s option, the interest rate on the outstanding borrowings may be the lenders base rate or the LIBOR plus a spread that is based on its long-term unsecured credit ratings. The 2007 Credit Agreement permits Northern Border to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. Northern Border is required to pay a facility fee of 0.05 per cent based on the principal amount of the commitment of $250 million. The term of the agreement is five years, with options for two one-year extensions.

Under the 2007 Credit Agreement, Northern Border is required to comply with certain financial, operational and legal covenants. Among other things, Northern Border is required to maintain a ratio of total debt to EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges) of no more than 4.75 to 1. Pursuant to the 2007 Credit Agreement, if one or more acquisitions are consummated in which the aggregate purchase price is $25 million or more, the allowable ratio of total debt to EBITDA is increased to 5.50 to 1 for the first three full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2007 Credit Agreement may become immediately due and payable. At December 31, 2007, Northern Border was in compliance with all of its financial covenants.

The fair value of Northern Border s variable rate debt was approximately the carrying value since the interest rates are periodically adjusted to reflect current market conditions. As of December 31, 2007, Northern Border s outstanding borrowings under its credit agreement were $166 million. The average interest rate on Northern Border s credit agreement at December 31, 2007 was 5.35 per cent.

Interest Rate Collar Agreement

In August 2007, Northern Border entered into a zero cost interest rate collar agreement (the Collar Agreement) to limit the variability of the interest rate on $140 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent. Northern Border has designated the Collar Agreement as a cash flow hedge. At December 31, 2007, Northern Border s balance sheet reflected an unrealized loss of approximately $1.9 million with a corresponding decrease to accumulated other comprehensive income (loss) related to the changes in fair value of the Collar Agreement since inception. Since inception, Northern Border has not recognized any amounts in income due to ineffectiveness of the Collar Agreement.

Long-Term Financing - Debt Securities

Northern Border periodically issues long-term debt securities to meet its capital resource requirements. All of Northern Border s outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Northern Border s senior notes issuances of $200 million due in 2009 and $250 million due in 2021 are borrowed at fixed interest rates of 7.75 per cent and 7.50 per cent, respectively. Northern Border intends to maintain the current schedule of maturities, which will result in no gains or losses on their respective repayments. Northern Border intends to refinance the senior notes due in 2009 with a mix of long-term fixed rate debt and short-term variable rate debt. The indentures of the notes do not limit the amount of unsecured debt Northern Border may incur but do restrict secured indebtedness. In 2007, Northern Border repaid all of the $150 million of its 6.25 per cent senior notes due May 1, 2007 with borrowings under the 2007 Credit Agreement. At December 31, 2007, the aggregate fair value of the outstanding senior notes was approximately $493 million. In 2007, interest expense related to the senior notes was $37.4 million.

CASH FROM OUR PIPELINE SYSTEMS

Cash Distribution Policies of Great Lakes and Northern Border

Distributions to partners are made on a pro rata basis according to each general partner s ownership percentage, approximately one month following the end of a quarter. Great Lakes and Northern Border s respective Management Committees determine the amount and timing of cash distributions, where the amount of such distributions is based on available cash flow as determined by a prescribed formula. Any changes to, or suspension of, Great Lakes or Northern Border s cash distribution policy requires the unanimous approval of its respective Management Committee.

Northern Border s Management Committee changed its cash distribution policy effective in January 2004 to distribute 100 per cent of the distributable cash flow based on earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. In 2006, upon the closing of the purchase and sale of the 20 per cent interest in Northern Border, the Northern Border Management Committee adopted certain changes to the Northern Border cash distribution policy related to financial ratio targets and equity contributions. The change defined minimum equity to total capitalization ratios to be used by the Northern Border Management Committee to establish the timing and amount of required equity contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by equity contributions.

On February 1, 2008, a cash distribution of $46.3 million was declared and paid by Northern Border for the fourth quarter of 2007, of which TC PipeLines 50 per cent share was $23.2 million. On February 1, 2008, a cash distribution of $25.0 million was declared and paid by Great Lakes for the fourth quarter of 2007, of which TC PipeLines 46.45 per cent share was $11.6 million.

Investing Activities for our Pipeline Systems

Capital spending for maintenance of existing facilities and growth projects were as follows for each of our investments:

(millions of dollars)	**2007**	**2006**	**2005**
Great Lakes[(a)] :			
Maintenance	**16.7**		
Growth			
Great Lakes capital spending	**16.7**		
Northern Border:			
Maintenance	**10.6**	10.4	18.3
Growth		10.5	10.3
Northern Border s capital spending	**10.6**	20.9	28.6
Tuscarora:			
Maintenance	**0.1**	0.3	0.2
Growth	**13.1**	1.3	0.7
Tuscarora s capital spending	**13.2**	1.6	0.9

(a) Great Lakes capital spending information includes only capital expenditures from the date of acquisition.

Our pipeline systems fund their investing activities primarily with operating cash, issuances of new debt or additional borrowings under existing facilities, and equity contributions from general partners.

In 2008, Great Lakes expects to invest approximately $20.3 million for maintenance capital expenditures. No significant growth capital expenditures are planned for 2008.

Northern Border s maintenance capital expenditures decreased $7.9 million in 2006 compared with 2005 due to a decrease in expenditures related to compressor station overhauls. Growth capital expenditures in 2006 and 2005 were primarily related to spending for the Chicago III Expansion project. In 2008, Northern Border expects to spend approximately $30 million for capital expenditures of which $13 million relates to maintenance capital and $17 million relates to growth capital in regards to the Des Plaines project, subject to receipt of the required regulatory approvals. Northern Border intends to finance half of its growth capital expenditures with equity contributions from its general partners.

$12.2 million of Tuscarora s growth capital expenditures in 2007 relate to the compressor station expansion project in Likely, California. In 2008, Tuscarora expects to spend an additional $7.0 million to fund the completion of the compressor station expansion. Tuscarora expects to fund these capital expenditures with operating cash flow.

CONTINGENCIES

Legal

Various legal actions or governmental proceedings that have arisen in the ordinary course of business are pending. Our pipeline systems believe that the resolution of these issues will not have a material adverse impact on their results of operations or financial position.

Environmental

Our pipeline systems are not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

RELATED PARTY TRANSACTIONS

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to ten years. Great Lakes earned $113.9 million of transportation revenues under these contracts for the period February 23, 2007 to December 31, 2007. This amount represents 48.2 per cent of total revenues earned by Great Lakes for the period February 23, 2007 to December 31, 2007. $52.9 million of transportation revenue is included in the Partnership s equity income from Great Lakes during the same period. Please read Item 1. Business , Item 1A. Risk Factors , and Item 13. Certain Relationships and Related Transactions for additional information regarding Great Lakes transportation agreements with TransCanada and ANR.

OUTLOOK

Great Lakes

At January 31, 2008, the remaining weighted average contract life of Great Lakes contracts was 2.4 years and substantially all of its design capacity was contracted on a firm basis for the first quarter of 2008. As of January 31, 2008, Great Lakes had approximately ten per cent of its design capacity uncontracted beginning in the second quarter of 2008. Dependent on competitive factors and prevailing market conditions, Great Lakes may discount transportation capacity as needed to optimize revenue.

Northern Border

At January 31, 2008, the weighted average contract life of Northern Border s contracts was 1.3 years and substantially all of its design capacity was contracted on a firm basis for the first quarter of 2008. As of January 31, 2008, Northern Border had approximately 890 MMcf/d or 37 per cent of its design capacity uncontracted beginning in the second quarter of 2008 and 48 per cent uncontracted by the end of 2008. Prevailing market conditions and increasing competitive factors in North America, including the Rockies Express Pipeline, could cause Northern Border to discount their rates or otherwise experience a reduction in their revenues. These factors will continue to impact Northern Border s ability to market this available capacity. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue.

Tuscarora

At January 31, 2008, the weighted average remaining contract life of Tuscarora s contracts was 10.4 years. As of January 31, 2008, Tuscarora has approximately five MMcf/d or two per cent of its design capacity uncontracted beginning in the second quarter of 2008.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

OVERVIEW

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that would occur assuming hypothetical future movements in interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates and the timing of transactions.

TC PipeLines is exposed to market risk due to interest rate fluctuations. Market risk is the risk of loss arising from adverse changes in market rates. We utilize financial instruments to manage the risks of certain identifiable or anticipated transactions and achieve a more predictable cash flow. Our risk management function follows established policies and procedures to monitor interest rates to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* we record financial instruments on the balance sheet as assets and liabilities based on fair value. We estimate the fair value of financial instruments using available market information and appropriate valuation techniques. Changes in financial instruments fair value are recognized in earnings unless the instrument qualifies as a hedge under SFAS No. 133 and meets specific hedge accounting criteria. Qualifying financial instruments gains and losses may offset the hedged items related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

INTEREST RATE RISK

TC PipeLines interest rate exposure results from its Senior Credit Facility, which is subject to variability in LIBOR interest rates. The Partnership regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. The notional amount hedged at December 31, 2007 was $475.0 million. $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $100.0 million of variable-rate debt is hedged by an interest rate option during the period from May 22, 2007 through May 22, 2009 to an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid will be 3.86 per cent. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The fair value of interest rate derivatives has been calculated using year-end market rates. At December 31, 2007, the fair value of the Partnership s interest rate swaps and options accounted for as hedges was negative $9.8 million.

At December 31, 2007, TC PipeLines had $507.0 million outstanding on its Senior Credit Facility. Utilizing the conditions of the interest rate swaps and options, if LIBOR interest rates hypothetically increased by one per cent compared to the rates in effect as of December 31, 2007, the Partnership s interest expense for the year ended December 31, 2007 would have increased by $1.4 million; and if LIBOR interest rates hypothetically decreased one per cent compared to the rates in effect as of December 31, 2007, the Partnership s interest expense for the year would have decreased by $2.0 million. These amounts have been determined by considering the impact of the hypothetical interest rates on variable rate borrowings outstanding as of December 31, 2007.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its credit facility. Northern Border regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. As of December 31, 2007, 73 per cent of Northern Border s outstanding debt was at fixed rates. In August 2007, Northern Border entered into a Collar Agreement to limit the variability of the interest rate on $140.0 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent.

Utilizing the conditions of the Collar Agreement, if interest rates hypothetically increased one per cent compared with rates in effect as of December 31, 2007, Northern Border s annual interest expense would increase and its net income would decrease by approximately $0.8 million; and if interest rates hypothetically decreased one per cent compared with rates in effect as of December 31, 2007, Northern Border s annual interest expense would decrease and its net income would increase by approximately $1.1 million.

Great Lakes and Tuscarora utilize fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates.

OTHER RISKS

The Partnership is influenced by the same factors that influence our pipeline systems. None of our pipeline systems own any of the natural gas they transport; therefore, they do not assume any of the related natural gas commodity price risk.

The state of Minnesota currently requires Great Lakes to pay use tax on the value of the shipper provided compressor fuel burned in its Minnesota compressor engines. Great Lakes is subject to primarily commodity price volatility and some volume volatility in determining the amount of use tax owed. If natural gas prices changed by $1 per million British thermal units, Great Lakes annual use tax expense would change by approximately $0.7 million.

The Partnership does not have any material foreign exchange risks.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the "Index to Financial Statements" on page F-1.

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

None.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Based on their evaluation of the Partnership s disclosure controls and procedures as of the end of the year covered by this annual report, the principal executive officer and principal financial officer of the general partner of the Partnership have concluded that the Partnership s disclosure controls and procedures were effective in ensuring that the information required to be disclosed by the Partnership in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the

SEC s rules and forms and that information required to be disclosed by the Partnership in the reports that the Partnership files or submits under the Exchange Act is accumulated and communicated to the management of the general partner of the Partnership, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2007, there has been no change in the Partnership s internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of our management, including our chief executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment according to the above criteria, management has concluded that our internal control over financial reporting was effective as of December 31, 2007 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. There were no material weaknesses.

Our independent registered public accounting firm, KPMG LLP, independently assessed the effectiveness of the Partnership s internal control over financial reporting. KPMG has issued an attestation report concurring with management s assessment, which is included on page F-3 of the financial statements included in this Form 10-K.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

TC PipeLines is a limited partnership and as such has no officers, directors or employees. Set forth below is certain information concerning the directors and officers of the general partner who manage the operations of TC PipeLines. Each director holds office for a one-year term or until his or her successor is earlier appointed. All officers of the general partner serve at the discretion of the Board of Directors of the general partner which is a wholly-owned subsidiary of TransCanada.

Name	Age	Position with General Partner
Russell K. Girling	45	Chairman, Chief Executive Officer and Director
Mark A.P. Zimmerman	43	President
Jack F. Jenkins-Stark	57	Independent Director
David L. Marshall	68	Independent Director
Walentin (Val) Mirosh	62	Independent Director
Gregory A. Lohnes	51	Director
Kristine L. Delkus	50	Director
Steven D. Becker	57	Director
Terry C. Ofremchuk	57	Vice-President, Taxation
Sean M. Brett	42	Vice-President and Treasurer
Donald J. DeGrandis	59	Secretary
Amy W. Leong	40	Controller, Principal Financial Officer

Mr. Girling was appointed a director of the general partner in April 1999 and Chief Executive Officer of the general partner in June 2006. Mr. Girling s principal occupation is President, Pipelines Division of TransCanada, a position he has held since June 2006. From March 2003 to June 2006, he was Executive Vice-President, Corporate Development and Chief Financial Officer of TransCanada. Prior to March 2003, Mr. Girling was Executive Vice-President and Chief Financial Officer of TransCanada. Mr. Girling is also a director of Agrium Inc.

Mr. Zimmerman was appointed President of the general partner in January 2007. Mr. Zimmerman s principal occupation is Vice-President, Commercial Transactions of TransCanada, a position he has held since June 2006. From September 2003 to June 2006, he was Director, Project Finance for TransCanada, and prior to September 2003, he was Director, Corporate Evaluations and Planning for TransCanada.

Mr. Jenkins-Stark was appointed a director of the general partner in July 1999. Mr. Jenkins-Stark s principal occupation is Chief Financial Officer of BrightSource Energy Inc. (designs and builds large scale solar plants that deliver solar energy in the form of steam and/or electricity), a position he has held since April 2007. Mr. Jenkins-Stark was Chief Financial Officer of Silicon Valley Bancshares (offering financial products and services, including commercial, investment, merchant and private banking and private equity services) from April 2004 to April 2007. Prior to that he was Vice-President, Business Operations and Technology at Itron Inc. (a manufacturer of automated meter reading technology and a developer of energy management software), a position he held from January 2004 to March 2004. In March 2003, Mr. Jenkins-Stark was named a Managing Director at Itron Inc. following the purchase of Silicon Energy Corp. (internet-based energy and data management software) by Itron Inc. Prior to the acquisition, Mr. Jenkins-Stark was Chief Financial Officer of Silicon Energy.

Mr. Marshall was appointed a director of the general partner in July 1999. Mr. Marshall is a corporate director.

Mr. Mirosh was appointed a director of the general partner in September 2004. Mr. Mirosh s principal occupation is Vice-President of NOVA Chemicals Corporation and President of Olefins and Feedstocks, division of NOVA Chemicals Corporation (commodity chemical company), a position he has held since July 2003. Mr. Mirosh was Partner, MacLeod, Dixon (law firm) from January 2002 to July 2003. Mr. Mirosh is also a director of Taylor NGL Limited Partnership and Superior Plus Income Fund.

Mr. Lohnes was appointed a director of the general partner in January 2007. Mr. Lohnes principal occupation is Executive Vice-President and Chief Financial Officer of TransCanada, a position he has held since June 2006. Prior to June 2006, he was President and Chief Executive Officer of Great Lakes Gas Transmission Company.

Ms. Delkus was appointed a director of the general partner in November 2003. Ms. Delkus principal occupation is Deputy General Counsel, Pipelines and Regulatory Affairs of TransCanada, a position she has held since September 2006. From June 2006 to September 2006, she was Vice-President, Pipeline Law and Regulatory Affairs of TransCanada. From December 2005 to June 2006, she was Vice-President, Law, Gas Transmission of TransCanada. Prior to December 2005, she was Vice-President, Law, Power and Regulatory.

Mr. Becker was appointed a director of the general partner in January 2007 and appointed Vice-President, Business Development of the general partner in September 2003. Mr. Becker s principal occupation is Vice-President, Pipeline Development of TransCanada, a position he has held since June 2006. From April 2003 to June 2006, he was Vice-President, Gas Development of TransCanada. Prior to April 2003, Mr. Becker was Vice-President, Market Development and Vice-President, Gas Strategy of TransCanada.

Mr. Ofremchuk was appointed Vice-President, Taxation of the general partner in July 2007. Mr. Ofremchuk s principal occupation is Manager, Corporate Taxation of TransCanada.

Mr. Brett was appointed Vice-President and Treasurer of the general partner in January 2007. Mr. Brett s principal occupation is Assistant Treasurer for TransCanada, a position he has held since January 2007. Prior to January 2007, he was Director, Capital Markets for TransCanada.

Mr. DeGrandis was appointed Secretary of the general partner in April 2005. Mr. DeGrandis principal occupation is Corporate Secretary of TransCanada, a position he has held since June 2006. From June 2004 to June 2006, he was Associate General Counsel, Corporate, Corporate Secretarial of TransCanada. Prior to June 2004, Mr. DeGrandis was Director of Corporate Legal Services and Senior Legal Counsel of TransCanada.

Ms. Leong was appointed principal financial officer of the general partner in January 2007 and Controller of the general partner in September 2003. Ms. Leong s principal occupation is Director, Pipeline Accounting of TransCanada, a position she has held since January 2005. From April 2003 until January 2005, Ms. Leong was Manager, Gas Transmission Accounting of TransCanada. Prior to April 2003, Ms. Leong was Manager, Regulatory Accounting and Capital Accounting of TransCanada.

AUDIT COMMITTEE FINANCIAL EXPERT

The Board of Directors has determined that David Marshall and Jack Jenkins-Stark are audit committee financial experts , are independent and are financially sophisticated as defined under applicable SEC and NASDAQ Stock Market Corporate Governance rules. The Board s affirmative determination for both David Marshall and Jack Jenkins-Stark was based on their respective education and extensive experience as chief financial officers for corporations that presented a breadth and level of complexity of accounting issues that are generally comparable to those of TC PipeLines.

IDENTIFICATION OF THE AUDIT COMMITTEE

The general partner of the Partnership has a separately designated audit committee consisting of three independent board members. The members of the committee are David Marshall, as Chair, Jack Jenkins-Stark and Walentin (Val) Mirosh. All members of the Audit Committee meet the criteria for independence as set forth under the rules of the SEC and those of the NASDAQ Stock Market. None of the Audit Committee members have participated in the preparation of the financial statements of the Partnership or any of its subsidiaries at any time during the past three years. In addition, all members of the audit committee are able to read and understand fundamental financial statements, including a company s balance sheet, income statement, and cash flow statement.

CODE OF ETHICS

TC PipeLines believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. The employees of the general partner, as employees of TransCanada, are subject to TransCanada s code of business ethics. In addition, the general partner has adopted a code of business ethics for its Chief Executive Officer, President and Principal Financial Officer and one which applies to its independent directors, being the code of business ethics for directors. All codes are published on its website at www.tcpipelineslp.com. If any substantive amendments are made to the code for senior officers or if any waivers are granted, the amendment or waiver will be published on TC PipeLines website or filed in a report on Form 8-K.

CORPORATE GOVERNANCE

The Audit Committee has adopted a charter which specifically provides that it is responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants engaged in preparing or issuing TC PipeLines audit report, that the committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and for the committee to be responsible for establishing procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters, including procedures for the confidential, anonymous submission by employees of the general partner concerns regarding questionable accounting or auditing matters. The committee has adopted TransCanada s Ethics help line in fulfillment of its responsibility to establish a confidential and anonymous whistle blowing process. The toll free Ethics Help-Line number and the audit committee s charter are published on TC PipeLines website at www.tcpipelineslp.com.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires the Partnership s directors and executive officers, and persons who own more than ten per cent of the common units, to file initial reports of ownership and reports of changes in ownership (Forms 3, 4, and 5) of the common units with the SEC and the NASDAQ Global Market. Executive officers, directors and greater than ten per cent unitholders are required by SEC regulation to furnish the Partnership with copies of all such forms that they file.

Based solely upon a review of reports on Forms 3 and 4 and amendments thereto furnished to the Partnership during its most recent fiscal year and reports on Form 5 and amendments thereto furnished to the Partnership with respect to its most recent fiscal year, and written representations from officers and directors of the general partner that no Form 5 was required, the Partnership believes that all filing requirements applicable to its officers, directors and beneficial owners under Section 16(a) were complied with during the year ended December 31, 2007.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and we do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We are managed by the executive officers of our general partner who are also our executive officers. The executive officers of our general partner are compensated directly by TransCanada.

The compensation policies and philosophy of TransCanada govern the types and amount of compensation granted each of the named executive officers. Since these policies and philosophy are those of TransCanada, we refer you to a discussion of those items as set forth in the Executive Compensation section of the TransCanada Management Proxy Circular on the TransCanada website at www.transcanada.com. The TransCanada Management Proxy Circular is produced by TransCanada pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Securities Exchange Act of 1934, as amended; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our general partner.

The board of directors of our general partner does not have a separate compensation committee, nor does it make any determination with respect to the amount of compensation to be paid to our executive officers. The board of our general partner does have responsibility for evaluating and determining the reasonableness of the total amount we are charged for managerial, administrative and operational support provided by TransCanada, and its affiliates, including our general partner. The board specifically approves the allocation of the salary of the CEO to the Partnership on an annual basis. Please read Item 13. Certain Relationships and Related Transactions for more information regarding this arrangement.

In addition to base salary, we also reimburse our general partner for certain benefit and incentive compensation expenses related to the officers of our general partner and employees of an affiliate of our general partner who perform services on our behalf. The base salaries that are allocable to us vary for each officer or employee of an affiliate of our general partner performing services on our behalf and are based on the amount of time an employee devotes to matters related to our business as compared to the amount of time such employee devotes to matters related to the business of TransCanada and its other affiliates. We are allocated and reimburse the general partner for each officer s salary expense. Other benefit and incentive compensation expenses related to our officers are reimbursed to the general partner based upon an agreed upon calculation.

The following table summarizes the salary allocated to and paid by us in 2006 and 2007 for our principal executive officer, president and principal financial officers. None of the other executive officers of our general partner allocated to us more than $100,000 related to their salary.

Summary Compensation Table

		Base Salary Allocated to the Partnership		
Name and Principal Position	**Year**	**Canadian Dollars**	**United States Dollar Equivalent (1)**	**Total (1)**
Russell K. Girling, Chief Executive Officer	2007	60,250	60,973	60,973
	2006	49,835	42,763	42,763
Mark A.P. Zimmerman, President	2007	102,500	103,729	103,729
Gregory A. Lohnes, Chief Financial Officer	2007			
	2006			
Amy W. Leong, Controller and Principal Financial Officer	2007	16,475	16,673	16,673
	2006	15,500	13,301	13,301

(1) The compensation of executive officers of the general partner is paid by TransCanada in Canadian dollars. The United States dollar equivalents have been calculated using the applicable December 31, 2007 and 2006 noon buying rates of 1.0120 and 0.8581, respectively, as reported by the Bank of Canada.

We reimburse our general partner for benefit and incentive compensation expenses based on a set formula, which expenses are attributable to additional compensation paid to each of them and other compensation and employment-related expenses, including TransCanada s restricted stock unit and stock option awards, retirement plans, health and welfare plans, employer-related payroll taxes, matching contributions made under a TransCanada s employee savings plan, and premiums for health and life insurance. This reimbursement is determined monthly and calculated based on total monthly base salary allocated to us multiplied by a factor of .38 for benefits and a factor of .30 for incentive compensation. The total amount reimbursed for benefits and incentive compensation were $334,678 in 2006 and $548,665 in 2007.

Director Compensation

Each director who is not an employee of TransCanada, the general partner or its affiliates (independent director) is entitled to a directors retainer fee of $20,000 per annum. The independent director appointed as Lead Director and chair of the Conflicts Committee is entitled to an additional fee of $6,000 per annum, while the independent director appointed as chair of the Audit Committee is entitled to an additional fee of $4,000 per annum. These fees are paid by the Partnership on a semi-annual basis. Each independent director is also paid a fee of $1,500 for attendance at each meeting of the Board of Directors and a fee of $1,500 for attendance at each meeting of a committee of the Board. The independent directors are reimbursed for out-of-pocket expenses incurred in the course of attending such meetings.

Director Compensation Table

Name	Fees Earned or Paid in Cash	Total
David L. Marshall	60,000	60,000
Jack F. Jenkins-Stark	64,500	64,500
Walentin (Val) Mirosh	53,000	53,000

In October 2007, a revised compensation plan was approved for independent directors. Effective January 1, 2008, the directors retainer fee was increased to $30,000 per annum from $20,000 per annum and directors will receive an annual grant of Partnership units under the Deferred Share Unit (DSU) Plan with a value of $20,000, as an equity component of the annual retainer. No adjustments were made to meeting attendance fees or retainers for the Lead Director and chair of Conflicts Committee or chair of Audit Committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of the voting securities of the Partnership as of February 25, 2008 by the general partner s directors, officers and certain beneficial owners. Executive officers of the general partner own shares of TransCanada, which in the aggregate amount to less than one per cent of TransCanada s issued and outstanding shares. Other than as set forth below, no person is known by the general partner to own beneficially more than five per cent of the voting securities of the Partnership.

Name and Business Address	Amount and Nature of Beneficial Ownership Number of Common Units(1)	Number of DSUs(2)	Per cent of Class(3)
TransCan Northern Ltd. (4) 450 1st Street SW Calgary, Alberta T2P 5H1	8,678,045		24.9
TC Pipelines GP, Inc. (5) (6) 450 1st Street SW Calgary, Alberta T2P 5H1	2,035,106		5.8
David L. Marshall (7) 450 1st Street SW Calgary, Alberta T2P 5H1	450	550	*
Walentin (Val) Mirosh (8) 10th Floor, 1000-7th Avenue SW Calgary, Alberta T2P 5L5		550	*
Jack F. Jenkins-Stark (9) 1999 Harrison Street, Suite 500 Oakland, CA 94612	4,933	550	*
Gregory A. Lohnes 450 1st Street SW Calgary, Alberta T2P 5H1			
Steven D. Becker 450 1st Street SW Calgary, Alberta T2P 5H1			
Russell K. Girling 450 1st Street SW Calgary, Alberta T2P 5H1	6,000		*
Kristine L. Delkus 450 1st Street SW Calgary, Alberta T2P 5H1			
Directors and Executive officers as a Group (10) (11) (12 persons)			*

---

(1) A total of 34,856,086 common units are issued and outstanding.

(2) A deferred share unit is a bookkeeping entry, equivalent to the value of a TC Pipelines common unit, and does not entitle the holder to voting or other shareholder rights, other than the accrual of additional deferred share units for the value of dividends. A director cannot redeem deferred share units until the director ceases to be a member of the Board. Directors can then redeem their units for cash or shares.

(3) Any deferred share units shall be deemed to be outstanding for the purpose of computing the percentage of outstanding common units owned by such person, but shall not be deemed to be outstanding for the purpose of computing the percentage of common units by any other person.

(4) TransCan Northern Ltd. is a wholly-owned indirect subsidiary of TransCanada.

(5) TC PipeLines GP, Inc. is a wholly-owned indirect subsidiary of TransCanada.

(6) TC PipeLines GP, Inc. owns an aggregate of two per cent general partner interest of TC PipeLines.

(7) 450 common units are held directly by Mr. Marshall.

(8) No common units are currently held by Mr. Mirosh.

(9) 4,933 common units are held by the Jenkins-Stark Family Trust dated June 16, 1995.

(10) With the exception of the two named directors above and Russell K. Girling, none of the other directors and executive officers hold any common units of TC PipeLines.

(11) Walentin (Val) Mirosh holds 726 shares of TransCanada, Russell K. Girling holds 394,108 options and 13,674 shares of TransCanada; Kristine L. Delkus holds 91,784 options and 3,874 shares of TransCanda; Steven D. Becker holds 103,275 options and 2,620 shares of TransCanada; Terry C. Ofremchuk holds 6,750 options and 5,216 shares of TransCanada; Gregory A. Lohnes holds 48,497 options and 9,880 shares of TransCanada; Amy W. Leong holds 5,600 options and 3,327 shares of TransCanada; Donald J. DeGrandis holds 17,300 options and 528 shares of TransCanada; Mark A.P. Zimmerman holds 20,413 options and 380 shares of TransCanada and Sean M. Brett holds 15,500 options of TransCanada, 9,713 shares of TransCanada and 500 Series U preferred shares of TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada. The directors and executive officers as a group hold 703,227 options of TransCanada, 49,938 shares of TransCanada and 500 Series U preferred shares of TransCanada PipeLines Limited. All options listed above are exercisable within 60 days from February 28, 2008.

* Less than one per cent.

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

At February 28, 2008, TransCan Northern owns 8,678,045 common units and the Partnership s general partner owns 2,035,106 common units, representing an aggregate 30.1 per cent limited partner interest in the Partnership. In addition, the general partner owns an aggregate two per cent general partner interest in the Partnership through which it manages and operates the Partnership. As a result, TransCanada s aggregate ownership interest in the Partnership is 32.1 per cent by virtue of its indirect ownership of the general partner and 30.1 per cent aggregate limited partner interest.

The general partner is accountable to TC PipeLines and the unitholders as a fiduciary. Neither the Delaware Revised Uniform Limited Partnership Act (Delaware Act) nor case law defines with particularity the fiduciary duties owed by general partners to limited partners of a limited partnership. The Delaware Act does provide that Delaware limited partnerships may, in their partnership agreements, restrict or expand the fiduciary duties owed by a general partner to limited partners and the partnership.

In order to induce the general partner to manage the business of TC PipeLines, the partnership agreement contains various provisions restricting the fiduciary duties that might otherwise be owed by the general partner. The following is a summary of the material restrictions of the fiduciary duties owed by the general partner to the limited partners:

- The partnership agreement permits the general partner to make a number of decisions in its sole discretion. This entitles the general partner to consider only the interests and factors that it desires and it shall have no duty or obligation to give any consideration to any interest of, or factors affecting, TC PipeLines, its affiliates or any limited partner. Other provisions of the partnership agreement provide that the general partner s actions must be made in its reasonable discretion.

- The partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be fair and reasonable to TC PipeLines. In determining whether a transaction or resolution is fair and reasonable the general partner may consider interests of all parties involved, including its own. Unless the general partner has acted in bad faith, the action taken by the general partner shall not constitute a breach of its fiduciary duty.

- The partnership agreement specifically provides that it shall not be a breach of the general partner s fiduciary duty if its affiliates engage in business interests and activities in competition with, or in preference or to the exclusion of, TC PipeLines. Further, the general partner and its affiliates have no obligation to present business opportunities to TC PipeLines.

- The partnership agreement provides that the general partner and its officers and directors will not be liable for monetary damages to TC PipeLines, the limited partners or assignees for errors of judgment or for any acts or omissions if the general partner and those other persons acted in good faith.

TC PipeLines is required to indemnify the general partner and its officers, directors, employees, affiliates, partners, members, agents and trustees (collectively referred to hereafter as the General Partner and others), to the fullest extent permitted by law, against liabilities, costs and expenses incurred by the General Partner and others. This indemnification is required if the General Partner and others acted in good faith and in a manner they reasonably believed to be in, or (in the case of a person other than the general partner) not opposed to, the best interests of TC PipeLines. Indemnification is required for criminal proceedings if the General Partner and others had no reasonable cause to believe their conduct was unlawful.

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee or other compensation in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $1.9 million for the year ended December 31, 2007.

Pursuant to our Partnership agreement, whenever a potential conflict of interest exists or arises between the general partner or any of its affiliates and the Partnership, any resolution or course of action by the general partner or its affiliates in respect of such conflict of interest shall be permitted if the resolution or course of action is deemed to be fair and reasonable to the Partnership. As such, the general partner has established a Conflicts Committee, of not less than two independent directors, to oversee all matters relating to the resolution of conflicts of interest and to provide to our Board of Directors recommendation for such resolution of conflicts of interest.

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation. The acquisition was partially financed through a private placement of common units for gross proceeds of $600.0 million which closed concurrently with the acquisition. TransCan Northern purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent interest simultaneously with the Partnership s acquisition of its interest. A wholly-owned subsidiary of TransCanada became the operator of Great Lakes through TransCanada s acquisition of Great Lakes Gas Transmission Company.

TCNB became the operator of Northern Border effective April 1, 2007. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. In connection with this transaction, TCNB became the operator of Tuscarora. TransCanada and its affiliates provide capital and operating services to our pipeline systems. TransCanada and its affiliates also incur costs on behalf of our pipeline systems, including, but not limited to, employee benefit costs, property and liability insurance costs, and transition costs. Total costs charged to our pipeline systems in 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at December 31, 2007 are summarized in the following table:

(millions of dollars)	Great Lakes	Northern Border	Tuscarora
Costs charged by TransCanada and its affiliates	25.6	22.5	1.8
Impact on the Partnership s net income	11.2	11.0	0.9
Amount owed to TransCanada and its affiliates	1.9	3.0	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to ten years. Great Lakes earned $113.9 million of transportation revenues under these contracts for the period February 23, 2007 to December 31, 2007. This amount represents 48.2 per cent of total revenues earned by Great Lakes for the period February 23, 2007 to December 31, 2007. $52.9 million of transportation revenue is included in the Partnership s equity income from Great Lakes during the same period. At December 31, 2007, $10.0 million is included in Great Lakes receivables in regards to the transportation contracts with TransCanada and its affiliates.

For the year ended December 31, 2007, the Partnership recorded transmission revenues of $19.4 million in regards to various contracts with Sierra Pacific Power Company, a wholly-owned subsidiary of Sierra Pacific Resources.

On May 8, 2007, the Partnership reimbursed TransCanada $2.8 million for third party costs related to the Partnership s acquisition of its interest in Great Lakes. On September 26, 2007, the Partnership reimbursed TransCanada $1.2 million for a working capital adjustment related to the Partnership s acquisition of its interest in Great Lakes.

On December 31, 2007, the Partnership acquired a one per cent general partner interest in Tuscarora from a wholly-owned subsidiary of TransCanada for $2.0 million. The purchase price of this acquisition was derived from the formula used to calculate the purchase price of a different one per cent general partner interest in Tuscarora which was purchased from Tuscarora Gas Pipeline Co, a wholly-owned subsidiary of Sierra Pacific Resources on the same day.

Item 14. Principal Accounting Fees and Services

The following table sets forth, for the periods indicated, the fees billed by the principal accountants.

	2007	2006
Audit Fees [(1)]	**310,745**	217,803
Audit Related Fees [(2)]	**170,014**	26,500
Tax Fees [(3)]		
All Other Fees [(3)]		

(1) Audit Fees include services performed related to Sarbanes-Oxley Act reporting requirements.

(2) The increase in Audit Related Fees is primarily due to prospectus work in connection with the Great Lakes acquisition.

(3) The Partnership has not engaged its external auditors for any tax or other services in 2007 or 2006.

AUDIT FEES

Audit fees include fees for the audit of annual GAAP financial statements, reviews of the related quarterly financial statements and related consents and comforts letters for documents filed with the SEC. Before our independent principal accountant is engaged each year for annual audit and other audit and any non-audit services, these services and fees are reviewed and approved by our Audit Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) (1) and (2) Financial Statements and Financial Statement Schedules

The financial statements filed as part of this report are listed in the Index to Financial Statements on page F-1.

(3) Exhibits

No.	Description
*+2.1	Partnership Interest Purchase and Sale Agreement dated as of December 31, 2005 by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP s Form 8-K filed on February 15, 2006 (File No. 000-26091)).
*+2.2	General Partnership Interest Purchase Agreement dated as of November 1, 2006 by and between Tuscarora Gas Pipeline Co. and TC Tuscarora Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP s Form 8-K filed on November 7, 2006 (File No. 000-26091)).
*+2.3	General Partner Interest Holder Agreement dated as of November 1, 2006 by and between Tuscarora Gas Pipeline Co. and TC Tuscarora Intermediate Limited Partnership (Exhibit 2.2 to TC PipeLines, LP s Form 8-K filed on November 7, 2006 (File No. 000-26091)).
*+2.4	Purchase and Sale Agreement among El Paso Great Lakes Company, L.C.C., as Seller, and TC GL Intermediate Limited Partnership and TransCanada PipeLine USA Ltd., as Buyers dated as of December 22, 2006 (Exhibit 2.1 to TC PipeLines, LP s Form 8-K filed on December 26, 2006 (File No. 000-26091)).
2.5	General Partnership Interest Purchase Agreement dated as of December 20, 2007 by and between TCPL Tuscarora Ltd. and TC Pipelines Tuscarora LLC.
*3.1	Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated May 28, 1999 (Exhibit 3.1 to TC PipeLines, LP s Form 10-K filed on March 28, 2000 (File No. 333-69947)).
3.1.1	Amendment to the Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated November 19, 2007.
*3.2	Certificate of Limited Partnership of TC PipeLines, LP (Exhibit 3.2 to TC PipeLines, LP s Form S-1 Registration Statement, Registration No. 333-69947 filed on December 30, 1998).
*4.1	Indenture, dated as of August 17, 1999 between Northern Border Pipeline Company and Bank One Trust Company, NA, successor to The First National Bank of Chicago, Trustee (Exhibit 4.1 to Northern Border Pipeline Company s Form S-4 Registration Statement, Registration No. 333-88577 filed on October 7, 1999).
*4.2	Indenture, Assignment and Security Agreement dated December 21, 1995 between Tuscarora Gas Transmission Company and Wilmington Trust Company, as trustee (Exhibit 99.1 to TC PipeLines, LP s Form 10-Q filed on November 13, 2000 (File No.333-69947)).
*4.3	Indenture dated September 17, 2001, between Northern Border Pipeline Company and Bank One Trust Company, N.A., Trustee (Exhibit 4.2 to Northern Border Pipeline Company s Form S-4 Registration Statement, Registration No. 333-73282 filed on November 13, 2001).
*4.4	Registration Rights Agreement between TC PipeLines, LP, TransCan Northern Ltd., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson MLP Fund, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Strome MLP Fund, LP, Royal Bank of Canada, Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation, Tortoise North American Energy Corporation, GPS Income Fund LP, GPS High Yield Equities Fund, HFR RVAGPS Master Trust, GPS New Equity Fund LP, TPG-Axon Partners, LP, Lehman Brothers Inc., Structured Finance Americas, LLC, The Cushing MLP Opportunity Fund I, LP, Swank MLP Convergence Fund, LP, and Citigroup Global Markets, Inc.

	dated February 22, 2007 (Exhibit 4.1 to TC PipeLines, LP s Form 8-K filed on February 23, 2007 (File No. 000-26091)).
*10.1	Contribution, Conveyance and Assumption Agreement among TC PipeLines, LP and certain other parties dated May 28, 1999 (Exhibit 10.2 to TC PipeLines, LP s Form 10-K filed on March 28, 2000 (File No. 333-69947)).
*10.2	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company dated April 6, 2006, by and between Northern Border Intermediate Limited Partnership and TC Pipelines Intermediate Limited Partnership (Exhibit 3.1 to Northern Border Pipeline Company s Form 8-K filed on April 12, 2006 (File No. 333-87753)).
*10.3	Revolving Credit Agreement, dated as of April 27, 2007, among Northern Border Pipeline Company, the lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, Wachovia Bank National Association, as Syndication Agent, BMO Capital Markets, Citibank, N.A. and Mizuho Corporate Bank, LTD., as Co-Documentation Agents, JP Morgan Chase Bank, N.A. and Export Development Canada, as Managing Agents and Wachovia Capital Markets, LLC and SunTrust Capital Markets, Inc., as Co-Lead Arrangers and Book Managers. (Exhibit 10.1 to Northern Border Pipeline Company s Form 10-Q filed on April 30, 2007 (File No. 333-88577)).
*10.4	Amended and Restated Revolving Credit and Term Loan Agreement among TC PipeLines, LP, the lenders from time to time party thereto, SunTrust Bank as Administrative Agent, UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents, BMO Capital Markets Financing Inc. and the Royal Bank of Scotland PLC, as Co-Syndication Agents, Deutsche Bank AG New York Branch and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Managing Agents, and SunTrust Capital Markets, Inc. as Arranger and Book Manager, dated February 13, 2007 (Exhibit 10.1 to TC PipeLines, LP s Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.5	Subordinated Loan Agreement between TC PipeLines, LP and TransCanada PipeLines Limited, dated February 13, 2007 (Exhibit 10.2 to TC PipeLines, LP s Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.6	Subordination and Intercreditor Agreement among TransCanada PipeLines Limited, TC PipeLines, LP, and SunTrust Bank, as Administrative Agent, dated February 13, 2007 (Exhibit 10.3 to TC PipeLines, LP s Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.7	Common Unit Purchase Agreement by and among TC PipeLines, LP and TransCan Northern Ltd., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson MLP Fund, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Strome MLP Fund, LP, Royal Bank of Canada, Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation, Tortoise North American Energy Corporation, GPS Income Fund LP, GPS High Yield Equities Fund, HFR RVAGPS Master Trust, GPS New Equity Fund LP, TPG-Axon Partners, LP, Lehman Brothers Inc., Structured Finance Americas, LLC, The Cushing MLP Opportunity Fund I, LP, Swank MLP Convergence Fund, LP, and Citigroup Global Markets, Inc. dated February 22, 2007 (Exhibit 10.1 to TC PipeLines, LP s Form 8-K filed on February 23, 2007 (File No. 000-26091)).
*10.8	Form of Conveyance, Contribution and Assumption Agreement among Northern Plains Natural Gas Company, Northwest Border Pipeline Company, Pan Border Gas Company, Northern Border Partners, L.P., and Northern Border Intermediate Limited Partnership. (Exhibit 10.16 to Northern Border Pipeline Company s Form S-1 Registration Statement filed on July 16, 1993 (Registration No. 33-66158)).
*10.9	Form of Contribution, Conveyance and Assumption Agreement among TC PipeLines, L.P., and Northern Border Intermediate Limited Partnership. (Exhibit 10.2 to TC PipeLines, LP s Form S-1/A filed on May 3, 1999 (File No. 333-69947)).
*10.10	Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. (Exhibit 10.2 to Northern Border Pipeline Company s Form 8-K filed on April 12, 2006 (File No. 333-88577)).
*10.11	Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated as of December 19, 2006 (Exhibit 10.11 to TC PipeLines, LP s Form 10-Kfiled on March 2, 2007 (File No. 000-26091)).
*10.12	Transportation Service Agreement FT4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 30, 2006. (Exhibit 10.1 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).

*10.13	Transportation Service Agreement FT4761 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.2 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.14	Transportation Service Agreement FT4762 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.3 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.15	Transportation Service Agreement FT4763 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.4 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.16	Transportation Service Agreement FT4764 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 30, 2006. (Exhibit 10.5 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.17	Transportation Service Agreement FT5840 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 1, 2005. (Exhibit 10.6 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.18	Transportation Service Agreement FT5841 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 1, 2005. (Exhibit 10.7 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.19	Transportation Service Agreement FT5842 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 30, 2006. (Exhibit 10.8 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
10.20	Transportation Service Agreement FT4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated December 7, 2007.
10.21	Transportation Service Agreement FT8742 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated December 6, 2007.
*10.22	Amended and Restated Agreement of Limited Partnership of Great Lakes Gas Transmission Limited Partnership between TransCanada GL, Inc., TC GL Intermediate Limited Partnership and Great Lakes Gas Transmission Company, dated February 22, 2007. (Exhibit 10.9 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.23	Operating Agreement between Great Lakes Gas Transmission Limited Partnership and Great Lakes Gas Transmission Company, dated April 5, 1990. (Exhibit 10.10 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
#10.24	The TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), dated October 18, 2007.
21.1	Subsidiaries of the Registrant.
23.1	Consent of KPMG LLP with respect to the financial statements of TC PipeLines, LP
23.2	Consent of KPMG LLP with respect to the financial statements of Great Lakes Gas Transmission Limited Partnership
23.3	Consent of KPMG LLP with respect to the financial statements of Northern Border Pipeline Company
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Consolidated Balance Sheets of TC PipeLines GP, Inc. as of December 31, 2006 and 2005. (Exhibit 99.1 to TC PipeLines, LP s Form 10-Q filed on April 30, 2007 (File No. 000-26091)).

* Indicates exhibits incorporated by reference.

+ Pursuant to item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Management contract or compensatory plan or arrangement.

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 on this 28th day of February 2008.

TC PIPELINES, LP
(A Delaware Limited Partnership)
by its general partner, TC PipeLines GP, Inc.

By:	/s/ Russell K. Girling
	Russell K. Girling Chairman, Chief Executive Officer and Director TC PipeLines GP, Inc. (Principal Executive Officer)
By:	/s/ Amy W. Leong
	Amy W. Leong Controller TC PipeLines GP, Inc. (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	**Title**	**Date**
/s/ Russell K. Girling Russell K. Girling	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2008
/s/ Amy W. Leong Amy W. Leong	Controller and Principal Financial Officer	February 28, 2008
/s/ Gregory A. Lohnes Gregory A. Lohnes	Director	February 28, 2008
/s/ Kristine L. Delkus Kristine L. Delkus	Director	February 28, 2008
/s/ Steven D. Becker Steven D. Becker	Director	February 28, 2008
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 28, 2008
/s/ Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	February 28, 2008

/s/ David L. Marshall David L. Marshall	Director	February 28, 2008

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP:

We have audited the accompanying consolidated balance sheets TC PipeLines, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners equity for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the General Partner s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TC PipeLines, LP and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TC PipeLines, LP s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2008 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ KPMG LLP

Calgary, Canada
February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP:

We have audited TC PipeLines, LP s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management of the General Partner of TC PipeLines, LP is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity s assets that could have a material effect on the financial statements.

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

In our opinion, TC PipeLines, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TC PipeLines, LP as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners equity for each of the years in the three-year period ended December 31, 2007, and our report dated February 27, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Calgary, Canada
February 27, 2008

TC PIPELINES, LP

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	2007	2006
Assets		
Current Assets		
Cash and short-term investments	**6.8**	4.0
Accounts receivable and other	**4.2**	2.5
	11.0	6.5
Investment in Great Lakes *(Note 3)*	**721.1**	
Investment in Northern Border *(Note 4)*	**541.9**	561.2
Plant, property and equipment *(Note 6)*	**134.1**	127.0
Goodwill *(Note 7)*	**81.7**	79.2
Other assets	**2.8**	3.9
	1,492.6	777.8
Liabilities and Partners Equity		
Current Liabilities		
Bank indebtedness	**1.4**	
Accounts payable	**4.8**	3.3
Accrued interest	**3.0**	1.3
Current portion of long-term debt *(Note 8)*	**4.6**	4.7
	13.8	9.3
Hedging deferrals	**9.9**	
Long-term debt *(Note 8)*	**568.8**	463.4
	592.5	472.7
Non-controlling interests *(Note 5)*		1.2
Partners Equity *(Note 9)*		
Common units	**892.3**	295.6
General partner	**19.1**	6.5
Accumulated other comprehensive (loss)/income	**(11.3)**	1.8
	900.1	303.9
	1,492.6	777.8

Subsequent events *(Note 18)*

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 (millions of dollars except per common unit amounts)	2007	2006	2005
Equity income from investment in Great Lakes *(Note 3)*	**49.0**		
Equity income from investment in Northern Border *(Note 4)*	**61.2**	56.6	45.7
Equity income from investment in Tuscarora *(Note 5)*		5.9	7.5
Transmission revenues	**27.2**	0.9	
Operating expenses	**(8.3)**	(2.7)	(2.0)
Depreciation	**(6.3)**	(0.2)	
Financial charges, net and other *(Note 10)*	**(33.8)**	(15.8)	(1.0)
Net income	**89.0**	44.7	50.2
Net income per common unit *(Note 11)*	**$ 2.51**	$ 2.39	$ 2.70
Common units outstanding, end of the year *(millions)*	**34.9**	17.5	17.5

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	2007	2006	2005
Net income	**89.0**	44.7	50.2
Other comprehensive (loss)/income			
Change associated with current period hedging transactions *(Note 16)*	**(11.4)**	1.6	
Change associated with current period hedging transactions of investees	**(1.7)**	(0.5)	(0.5)
	(13.1)	1.1	(0.5)
Total comprehensive income	**75.9**	45.8	49.7

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	2007	2006	2005
Cash Generated From Operations			
Net income	**89.0**	44.7	50.2
Depreciation	**6.3**	0.2	
Amortization of other assets *(Note 10)*	**0.4**	0.9	
Non-controlling interests *(Note 5)*	**0.2**		
Equity allowance for funds used during construction	**(0.2)**		
Decrease/(increase) in operating working capital	**2.9**	0.3	(0.1)
	98.6	46.1	50.1
Investing Activities			
Return of capital from Great Lakes	**12.3**		
Return of capital from Northern Border	**25.1**	23.8	15.2
Return of capital from Tuscarora		1.8	0.8
Investment in Great Lakes *(Note 3)*	**(733.0)**		
Investment in Northern Border *(Note 4)*	**(7.5)**	(311.1)	
Investment in Tuscarora, net of cash acquired *(Notes 5 and 7)*	**(3.9)**	(97.2)	(0.3)
Increase in cash due to the consolidation of Tuscarora *(Note 7)*		2.6	
Capital expenditures	**(13.2)**		
Other assets	**(1.2)**	(1.9)	
	(721.4)	(382.0)	15.7
Financing Activities			
Distributions paid *(Note 12)*	**(86.7)**	(43.5)	(43.0)
Equity issuances, net	**607.0**		
Long-term debt issued *(Note 8)*	**171.5**	707.0	
Long-term debt repaid *(Note 8)*	**(66.2)**	(325.9)	(23.0)
	625.6	337.6	(66.0)
Increase/(decrease) in cash and short-term investments	**2.8**	1.7	(0.2)
Cash and short-term investments, beginning of year	**4.0**	2.3	2.5
Cash and short-term investments, end of year	**6.8**	4.0	2.3
Interest payments made	**34.3**	13.9	1.0

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS EQUITY

	Common Units (millions of units)	Common Units (millions of dollars)	General Partner (millions of dollars)	Accumulated Other Comprehensive Income/(Loss) (millions of dollars)	Partners Equity (millions of units)	Partners Equity (millions of dollars)
Partners equity at December 31, 2004	17.5	287.4	6.3	1.2	17.5	294.9
Net income		47.3	2.9			50.2
Distributions paid		(40.3)	(2.7)			(43.0)
Other comprehensive loss				(0.5)		(0.5)
Partners equity at December 31, 2005	17.5	294.4	6.5	0.7	17.5	301.6
Net income		41.8	2.9			44.7
Distributions paid		(40.6)	(2.9)			(43.5)
Other comprehensive income				1.1		1.1
Partners equity at December 31, 2006	17.5	295.6	6.5	1.8	17.5	303.9
Net income		81.3	7.7			89.0
Equity issuances, net	17.4	594.4	12.6		17.4	607.0
Distributions paid		(79.0)	(7.7)			(86.7)
Other comprehensive loss				(13.1)		(13.1)
Partners equity at December 31, 2007	**34.9**	**892.3**	**19.1**	**(11.3)**	**34.9**	**900.1**

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

TC PIPELINES, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiary limited partnerships and limited liability company, including TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership, all Delaware limited partnerships, and TC Pipelines Tuscarora LLC, are collectively referred to herein as TC PipeLines or the Partnership. TC PipeLines was formed by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America.

TC PipeLines, through TC GL Intermediate Limited Partnership, owns a 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes), a Delaware limited partnership. Great Lakes owns a 2,115-mile pipeline that transports natural gas serving markets in Minnesota, Wisconsin, Michigan and Eastern Canada.

TC PipeLines, through TC PipeLines Intermediate Limited Partnership, owns a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border), a Texas general partnership. Northern Border owns a 1,249-mile U.S. interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to markets in the Midwestern U.S.

TC PipeLines also, through TC Tuscarora Intermediate Limited Partnership and TC Pipelines Tuscarora LLC, wholly-owns Tuscarora Gas Transmission Company (Tuscarora), a Nevada general partnership. Tuscarora owns a 240-mile U.S. interstate pipeline system that transports natural gas from Oregon, where it interconnects with facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, to Northern Nevada.

TC PipeLines is managed by its general partner, TC PipeLines GP, Inc. (TC PipeLines GP), a wholly-owned subsidiary of TransCanada. The general partner provides administrative services for the Partnership and is reimbursed for its costs and expenses. In addition to its aggregate two per cent general partner interest in TC PipeLines, on a combined basis, the general partner owns 2,035,106 common units, representing an effective 7.7 per cent limited partner interest in the Partnership at December 31, 2007. TransCanada also indirectly holds 8,678,045 common units representing an effective 24.4 per cent limited partner interest in the Partnership at December 31, 2007.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The accompanying financial statements and related notes present the financial position of the Partnership as of December 31, 2007 and 2006 and the results of its operations, cash flows and changes in partners equity for the years ended December 31, 2007, 2006 and 2005. The Partnership uses the equity method of accounting for its investments in Great Lakes and Northern Border, over which it is able to exercise significant influence. TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006. On this date, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora and as a result of acquiring a controlling interest in Tuscarora, began to consolidate Tuscarora s operations. Amounts are stated in U.S. dollars. Certain comparative figures have been reclassified to conform to the current year s presentation.

(b) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates.

(c) Cash and Short-Term Investments

The Partnership s short-term investments with original maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

(d) Plant, Property and Equipment

Plant, property and equipment relates solely to Tuscarora and is stated at original cost. Costs of restoring the land above and around the pipeline are capitalized to pipeline facilities and depreciated over the remaining life of the related pipeline facilities. Depreciation of pipeline facilities and compression equipment is provided on a straight-line composite basis over the estimated useful life of the pipeline of 30 years and of the compression equipment of 25 years. Metering and other is depreciated on a straight-line basis over the estimated useful lives of the equipment, which range from 3 to 30 years. Repair and maintenance costs are expensed as incurred. Costs that are considered a betterment are capitalized. An allowance for funds used during construction, using the rate of return on rate base approved by the Federal Energy Regulatory Commission (FERC), is capitalized and included in the cost of plant, property and equipment.

Long-lived assets are assessed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amounts of such assets exceed the fair value of the assets.

(e) Partners Equity

Costs incurred in connection with the issuance of units are deducted from the proceeds received.

(f) Revenue Recognition

Transmission revenues are recognized in the period in which the service is provided. When rate cases are pending final FERC approval, a portion of revenue collected is subject to possible refund. As of December 31, 2007, the Partnership has not recognized any transmission revenue that is subject to refund.

(g) Income Taxes

As a partnership, TC PipeLines is not subject to Federal or state income tax. The tax effect of the Partnership s activities accrues to its partners. The Partnership s taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statement of income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership s net assets for financial and income tax purposes cannot be readily determined because all information regarding each partner s tax attributes related to the partnership is not available.

(h) Acquisitions and Goodwill

The Partnership accounts for business acquisitions using the purchase method of accounting and accordingly the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. The excess of the purchase price over the fair value of net assets acquired is attributed to goodwill. Goodwill is not amortized for accounting purposes; however, it is tested on an annual basis for impairment, or more frequently if any indicators of impairment are evident.

(i) Derivative Financial Instruments and Hedging Activities

The Partnership utilizes derivative and other financial instruments to manage its exposure to changes in interest rates. Derivatives and other instruments must be designated as hedges and be effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow hedges, unrealized gains or losses relating to derivatives are recognized as other comprehensive income. In the event that a derivative does not meet the designation or effectiveness criteria, any unrealized gain or loss on the instrument is recognized immediately in earnings.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related gains or losses are immediately recognized in earnings and amounts previously recognized in other comprehensive income are reclassified to earnings prospectively. Costs associated with the purchase of certain hedging instruments are deferred and amortized against interest expense.

(j) Asset Retirement Obligation

Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations,* provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time is classified as an operating expense. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, ordinances, or written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

FIN 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of SFAS No. 143,* clarifies the term conditional asset retirement obligation, as used in SFAS No. 143 and the circumstances under which an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. No amount is recorded for asset retirement obligations relating to the assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements. Management believes it is reasonable to assume that all retirement costs associated with the pipeline system will be recovered through rates in future periods.

(k) Government Regulation

Tuscarora, our wholly-owned pipeline system, is subject to regulation by the FERC. The Partnership s accounting policies conform to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, certain assets or liabilities that result from the regulated ratemaking process are recorded that would not be recorded under generally accepted accounting principles for non-regulated entities. The Partnership regularly evaluates the continued applicability of SFAS No. 71, considering such factors as regulatory changes, the impact of competition, and the ability to recover regulatory assets. As of December 31, 2007 and 2006, the Partnership has no regulatory assets or liabilities.

NOTE 3 INVESTMENT IN GREAT LAKES

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent interest concurrent with the Partnership s acquisition of its interest. Effective February 22, 2007, a wholly-owned subsidiary of TransCanada became the operator of Great Lakes. Great Lakes is regulated by the FERC.

TC GL Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Great Lakes. TC PipeLines, LP holds a 98.9899 per cent limited partnership interest in TC GL Intermediate Limited Partnership.

The Partnership uses the equity method of accounting for its investment in Great Lakes. TC PipeLines equity income from its investment in Great Lakes amounted to $49.0 million for the period February 23, 2007 to December 31, 2007. Great Lakes had no undistributed earnings for the year ended December 31, 2007.

The following sets out summarized financial information for Great Lakes as at December 31, 2007 and for the period February 23, 2007 to December 31, 2007:

Summarized Consolidated Great Lakes Balance Sheet

December 31 (millions of dollars)	**2007**
Assets	
Cash and short-term investments	**32.0**
Other current assets	**55.5**
Plant, property and equipment, net	**969.2**
	1,056.7
Liabilities and Partners Equity	
Current liabilities	**50.7**
Deferred credits	**0.4**
Long-term debt, including current maturities	**440.0**
Partners capital	**565.6**
	1,056.7

Summarized Consolidated Great Lakes Income Statement

For the period February 23 to December 31 (millions of dollars)	**2007**
Transmission revenues	**236.2**
Operating expenses	**(53.7)**
Depreciation	**(49.4)**
Financial charges, net and other	**(27.6)**
Net income	**105.5**

NOTE 4 INVESTMENT IN NORTHERN BORDER

The Partnership owns a 50 per cent general partner interest in Northern Border. The remaining 50 per cent partnership interest in Northern Border is held by ONEOK Partners, L.P. (ONEOK), a publicly traded limited partnership. The Northern Border system was operated by ONEOK Partners GP, LLC (ONEOK Partners GP), a wholly-owned subsidiary of ONEOK, Inc. during the three months ended March 31, 2007. Effective April 1, 2007, TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became the operator of Northern Border. Northern Border is regulated by the FERC.

TC PipeLines Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Northern Border. TC PipeLines, LP holds a 98.9899 per cent limited partnership interest in TC PipeLines Intermediate Limited Partnership.

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border. The Partnership uses the equity method of accounting for its investment in Northern Border. TC PipeLines equity income for the year ended December 31, 2006 includes 30 per cent of the net income of Northern Border up to April 6, 2006 and 50 per cent thereafter. Equity income from Northern Border includes amortization of a $10 million transaction fee paid to the operator of Northern Border as an inducement to become operator at the time of the additional 20 per cent acquisition in April 2006. TC PipeLines equity income from its investment in Northern Border amounted to $61.2 million for the year ended December 31, 2007 (2006 - $56.6 million; 2005 - $45.7 million). Northern Border had no undistributed earnings for the years ended December 31, 2007, 2006 and 2005.

The following sets out summarized financial information for Northern Border as at December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005:

Summarized Northern Border Balance Sheet

December 31 (millions of dollars)	**2007**	**2006**
Assets		
Cash and short-term investments	**22.9**	11.0
Other current assets	**39.8**	35.5
Plant, property and equipment, net	**1,428.3**	1,475.7
Other assets	**23.9**	22.5
	1,514.9	1,544.7
Liabilities and Partners Equity		
Current liabilities	**53.4**	47.7
Deferred credits and other	**8.1**	2.1
Long-term debt, including current maturities and notes payable	**615.3**	619.8
Partners equity		
Partners capital	**840.5**	874.1
Accumulated other comprehensive (loss)/income	**(2.4)**	1.0
	1,514.9	1,544.7

Summarized Northern Border Income Statement

Year ended December 31 (millions of dollars)	**2007**	**2006**	**2005**
Transmission revenues	**309.4**	310.9	321.7
Operating expenses	**(83.5)**	(81.0)	(70.8)
Depreciation	**(60.7)**	(58.7)	(58.1)
Financial charges, net and other	**(41.1)**	(41.3)	(40.5)
Net income	**124.1**	129.9	152.3

NOTE 5 INVESTMENT IN TUSCARORA

As of December 31, 2007, the Partnership wholly-owns Tuscarora. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources. Prior to this acquisition, the Partnership used the equity method of accounting for its investment in Tuscarora. Subsequent to this acquisition, the Partnership used the consolidation method of accounting for its investment in Tuscarora. On December 31, 2007, the Partnership acquired the remaining two per cent general partner interest in Tuscarora, with one per cent purchased from a wholly-owned subsidiary of TransCanada and the other one per cent purchased from Tuscarora Gas Pipeline Co. Tuscarora is operated by TCNB. Tuscarora is regulated by the FERC.

The Partnership recorded net income from Tuscarora under the consolidation method of $11.4 million and $0.4 million for the year ended December 31, 2007 and the period December 20, 2006 to December 31, 2006, respectively. TC PipeLines equity income from its investment in Tuscarora amounted to $5.9 million and $7.5 million for the period January 1, 2006 to December 19, 2006 and the year ended December 31, 2005, respectively. Tuscarora had no undistributed earnings for the years ended December 31, 2007, 2006 and 2005. For the year ended

December 31, 2007, the following customers contributed to more than 10 per cent of Tuscarora s revenue: Sierra Pacific Power Company (72 per cent), Southwest Gas Company (13 per cent) and Barrick Goldstrike Mines (11 per cent).

The following sets out summarized financial information for Tuscarora as at December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005:

Summarized Tuscarora Balance Sheet

December 31 (millions of dollars)	2007	2006
Assets		
Cash and short-term investments	**5.5**	2.2
Other current assets	**2.6**	2.5
Plant, property and equipment, net	**134.1**	127.0
Other assets	**1.2**	1.2
	143.4	132.9
Liabilities and Partners Equity		
Current liabilities	**6.1**	2.4
Long-term debt, including current maturities	**66.4**	71.1
Partners equity		
Partners capital	**70.9**	59.3
Accumulated other comprehensive income		0.1
	143.4	132.9

Summarized Tuscarora Income Statement

Year ended December 31 (millions of dollars)	2007	2006	2005
Transmission revenues	**27.2**	29.5	32.3
Operating expenses	**(4.9)**	(4.7)	(4.4)
Depreciation	**(6.3)**	(6.2)	(6.2)
Financial charges, net and other	**(4.4)**	(5.3)	(5.6)
Net income	**11.6**	13.3	16.1

Summarized Tuscarora Cash Flow Statement

Year ended December 31 (millions of dollars)	2007	2006	2005
Cash flows provided by operating activities	**19.9**	20.5	22.3
Cash flows used in investing activities	**(13.2)**	(1.5)	(0.9)
Cash flows used in financing activities	**(3.4)**	(20.6)	(21.2)
Increase/(decrease) in cash and short-term investments	**3.3**	(1.6)	0.2
Cash and short-term investments, beginning of year	**2.2**	3.8	3.6
Cash and short-term investments, end of year	**5.5**	2.2	3.8

NOTE 6 PLANT, PROPERTY AND EQUIPMENT

		2007			2006	
December 31 (millions of dollars)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Tuscarora						

Pipeline	**146.6**	**53.1**	**93.5**	146.1	48.2	97.9
Compression	**25.0**	**5.5**	**19.5**	25.0	4.5	20.5
Metering and other	**11.0**	**3.1**	**7.9**	10.0	2.7	7.3
Under construction	**13.2**		**13.2**	1.3		1.3
	195.8	**61.7**	**134.1**	182.4	55.4	127.0

NOTE 7 ACQUISITIONS

Great Lakes

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation (El Paso). The total purchase price was $942.4 million, subject to certain closing adjustments, and included the indirect assumption of $209.0 million of debt. The acquisition was partially financed through a private placement of common units for gross proceeds of $600.0 million which closed concurrently with the acquisition. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with the acquisition.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated using an estimate of fair value of the net assets at the date of acquisition. The difference between the purchase price and the estimated fair value of net assets of $457.5 million, being goodwill, was recorded as part of the Partnership s investment in Great Lakes.

Great Lakes business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Great Lakes were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisition.

TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent general partner interest simultaneously with the Partnership s acquisition of its interest. In connection with these transactions, a wholly-owned subsidiary of TransCanada became the operator of Great Lakes.

Northern Border

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border for $298.0 million plus a $10.0 million transaction fee payable to TCNB, bringing the Partnership s total interest to 50 per cent. Through the acquisition, TC PipeLines indirectly assumed $121.7 million of debt. The Partnership funded the transaction through a Bridge Loan Credit Facility (see note 8). In connection with this transaction, TCNB became the operator of Northern Border in April 2007.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated using an estimate of fair value of the net assets at the date of acquisition. The difference between the purchase price and the fair value of net assets of $115.0 million, being goodwill, was recorded as part of the Partnership s investment in Northern Border. The $10.0 million transaction fee payable to the operator has been recorded as part of the Partnership s investment in Northern Border and is being amortized over the term of the related operating agreement.

Northern Border s business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Northern Border were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisition.

Tuscarora

On December 19, 2006, the Partnership acquired an additional 49 per cent general partnership interest in Tuscarora for $99.8 million. Through the acquisition TC PipeLines indirectly assumed $37.5 million of Tuscarora debt. The Partnership funded the transaction through the Senior Credit Facility (see note 8). In connection with this transaction, TCNB became the operator of Tuscarora.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated as follows using an estimate of fair value of the assets acquired and liabilities assumed at the date of acquisition:

Purchase Price Allocation (millions of dollars)	Acquisition of additional 49% interest
Current assets	4.7
Plant, property and equipment	56.6
Other non-current assets	0.7
Goodwill	79.1
Current liabilities	(2.6)
Long-term debt	(37.5)
Non-controlling interests	(1.2)
	99.8

On December 31, 2007, the Partnership acquired the other two per cent general partner interest in Tuscarora. One per cent was purchased from a wholly-owned subsidiary of TransCanada, while the other one per cent was purchased from Tuscarora Gas Pipeline Co. for a total purchase price of $3.9 million. The acquisitions were accounted for using the purchase method of accounting. The difference between the combined purchase prices and the non-controlling interest recorded on the Partnership s balance sheet of $2.6 million was recorded as goodwill.

Tuscarora s business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Tuscarora were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisitions.

Pro forma financial information for the Great Lakes, Northern Border and Tuscarora acquisitions

The following unaudited Partnership pro forma financial information for the years ended December 31, 2007 and 2006 has been prepared as if the significant acquisitions mentioned above occurred on January 1, 2006:

Year ended December 31 (millions of dollars except per unit amounts)	2007	2006
Equity income from investment in Great Lakes	**59.6**	56.8
Equity income from investment in Northern Border	**61.2**	64.1
Transmission revenues	**27.2**	29.5
Net income	**98.3**	99.9
Net income per common unit	**$ 2.58**	$ 2.70

NOTE 8 CREDIT FACILITIES AND LONG-TERM DEBT

(millions of dollars)	2007	2006
Senior Credit Facility	**507.0**	397.0
Series A Senior Notes	**54.5**	57.9
Series B Senior Notes	**5.5**	6.0
Series C Senior Notes	**6.4**	7.2
	573.4	468.1

On February 28, 2006, the Partnership renewed a $20.0 million unsecured credit facility (Revolving Credit Facility). In 2006, TC PipeLines repaid the Revolving Credit Facility in full and it was terminated. The interest rate on the Revolving Credit Facility averaged 5.60 per cent for the year ended December 31, 2006.

On March 31, 2006, the Partnership entered into an unsecured credit agreement for a $310.0 million credit facility (Bridge Loan Credit Facility) with a banking syndicate. Borrowings under the Bridge Loan Credit Facility bore interest, at the option of the Partnership, at the LIBOR or the base rate plus an applicable margin. On April 5, 2006, the Partnership borrowed $307.0 million under the Bridge Loan Credit Facility to finance the purchase price and a $10.0 million transaction fee payable in connection with the acquisition of an additional 20 per cent general partner interest in Northern Border. The remaining $3.0 million commitment under the Bridge Loan Credit Facility was terminated. On December 12, 2006, the Bridge Loan Credit Facility was refinanced through a $297.0 million draw on a $410.0 million credit agreement (Senior Credit Facility) with a banking syndicate and the use of $10.0 million cash on hand. The interest rate on the Bridge Loan Credit Facility averaged 6.29 per cent for the year ended December 31, 2006.

On December 12, 2006, the Partnership entered into a credit agreement for the Senior Credit Facility. On December 19, 2006, TC PipeLines borrowed an additional $100.0 million under the Senior Credit Facility to finance the purchase price of an additional 49 per cent general partner interest in Tuscarora.

On February 13, 2007, the Senior Credit Facility was amended and restated in connection with the Great Lakes acquisition. The amount available under the Senior Credit Facility increased from $410.0 million to $950.0 million, consisting of a $700.0 million senior term loan and a $250.0 million senior revolving credit facility, with $194.0 million of the senior term loan available being terminated upon closing of the Great Lakes acquisition. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. On November 29, 2007, $18.0 million of the senior term loan was repaid and hence terminated, leaving $488.0 million available and outstanding under the senior term loan. At December 31, 2007, $19.0 million is outstanding under the senior revolving credit facility, leaving $231.0 million available for future borrowings.

The Senior Credit Facility matures on December 12, 2011, at which time all amounts outstanding will be due and payable. Amounts borrowed may be repaid in part or in full prior to that time without penalty. Borrowings under the Senior Credit Facility will bear interest based, at the Partnership s election, on the LIBOR or the prime rate plus, in either case, an applicable margin. There was $507.0 million outstanding under the Senior Credit Facility at December 31, 2007 (2006 - $397.0 million). The interest rate on the Senior Credit Facility averaged 6.01 per cent for the year ended December 31, 2007 (2006 6.16 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.75 per cent for the year ended December 31, 2007. Prior to hedging activities, the interest rate was 5.62 per cent at December 31, 2007 (2006 6.07 per cent). At December 31, 2007, the Partnership was in compliance with its financial covenants.

In 1995, Tuscarora issued $91.7 million of 7.13 per cent senior secured notes, which mature on December 21, 2010 (Series A). In 2000, Tuscarora issued $8.0 million of 7.99 per cent senior secured notes, which mature on December 21, 2010 (Series B). In 2002, Tuscarora issued $10.0 million of 6.89 per cent senior secured notes, which mature on December 21, 2012 (Series C). The Series A, Series B and Series C notes (collectively, the Notes) have a final payment at maturity of $46.7 million, $4.1 million and $2.7 million, respectively. The Notes are secured by Tuscarora s transportation contracts, supporting agreements and substantially all of Tuscarora s property. The credit agreement for the Notes contains certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners.

Annual maturities of the Senior Credit Facility and the Notes are summarized as follows:

(millions of dollars)	
2008	4.6
2009	4.4
2010	53.5
2011	507.8
2012	3.1
	573.4

NOTE 9 PARTNERS EQUITY

On February 22, 2007, the Partnership completed a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million which closed concurrently with the Great Lakes acquisition. TransCan Northern Ltd. (TransCan Northern), a wholly-owned subsidiary of TransCanada, purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

At December 31, 2007, Partners equity consists of 34,856,086 common units representing an aggregate 98 per cent limited partner interest in the Partnership (including 2,035,106 common units held by the general partner and 8,678,045 common units held by TransCan Northern) and an aggregate two per cent general partner interest. In aggregate, the general partner s interests represent an effective 7.7 per cent ownership in the Partnership at December 31, 2007 (December 31, 2006 13.4 per cent).

NOTE 10 FINANCIAL CHARGES, NET AND OTHER

Year ended December 31 (millions of dollars)	**2007**	**2006**	**2005**
Interest expense on long-term debt	**34.9**	14.8	
Interest expense on short-term debt	**0.3**	0.3	1.1
Interest income	**(0.9)**	(0.4)	(0.1)
Amortization of other assets	**0.4**	0.9	
Other	**(0.9)**	0.2	
	33.8	15.8	1.0

NOTE 11 NET INCOME PER COMMON UNIT

Net income per common unit is computed by dividing net income, after deduction of the general partner s allocation, by the weighted average number of common units outstanding. The general partner s allocation is equal to an amount based upon the general partner s two per cent interest, adjusted to reflect an amount equal to incentive distributions. Incentive distributions are received by the general partner if quarterly cash distributions on the common units exceed levels specified in the partnership agreement. Net income per common unit was determined as follows:

Year ended December 31 (millions of dollars except per unit amounts)	**2007**	**2006**	**2005**
Net income	**89.0**	44.7	50.2
Net income allocated to general partner			
General partner interest	**(1.8)**	(0.9)	(1.0)
Incentive distribution income allocation	**(5.9)**	(2.0)	(1.9)
	(7.7)	(2.9)	(2.9
Net income allocable to common units	**81.3**	41.8	47.3
Weighted average common units outstanding *(millions)*	**32.3**	17.5	17.5
Net income per common unit	**$ 2.51**	$ 2.39	$ 2.70

NOTE 12 CASH DISTRIBUTIONS

The Partnership makes cash distributions to its partners with respect to each calendar quarter within 45 days after the end of each quarter. Distributions are based on available cash, which includes all cash and cash equivalents of the Partnership and working capital borrowings less reserves established by the general partner. The Unitholders currently receive a quarterly distribution of $0.665 per unit if and to the extent there is sufficient available cash.

As an incentive, the general partner s percentage interest in quarterly distributions is increased after certain specified target levels are met. The incremental incentive distributions payable to the General Partner are 15 per cent, 25 per cent, and 50 per cent of all quarterly distributions of Available Cash that exceed target levels of $0.45, $0.5275 and $0.69, respectively, per unit. For the year ended December 31, 2007, the Partnership distributed $2.565 per unit (2006 - $2.325 per unit; 2005 - $2.30 per unit). The distributions for the year ended December 31, 2007 included incentive distributions to the general partner in the amount of $5.9 million (2006 - $2.0 million; 2005 - $1.9 million). Partnership income is allocated to the general partner and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated 100 per cent to the general partner.

NOTE 13 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee or other compensation in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $1.9 million for the year ended December 31, 2007 (2006 - $1.2 million; 2005 - $1.1 million).

A wholly-owned subsidiary of TransCanada became the operator of Great Lakes through TransCanada s acquisition of Great Lakes Gas Transmission Company on February 22, 2007. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. In connection with this transaction, TCNB became the operator of Tuscarora. TransCanada and its affiliates provide capital and operating services to our pipeline systems. TransCanada and its affiliates incur costs on behalf of our pipeline systems, including, but not limited to, employee benefit costs, property and liability insurance costs, and transition costs. Total costs charged to our pipeline systems in 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at December 31, 2007 are summarized in the following table:

(millions of dollars)	**Great Lakes**	**Northern Border**	**Tuscarora**
Costs charged by TransCanada and its affiliates	25.6	22.5	1.8
Impact on the Partnership s net income	11.2	11.0	0.9
Amount owed to TransCanada and its affiliates	1.9	3.0	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to ten years. Great Lakes earned $113.9 million of transportation revenues under these contracts for the period February 23, 2007 to December 31, 2007. This amount represents 48.2 per cent of total revenues earned by Great Lakes for the period February 23, 2007 to December 31, 2007. $52.9 million of transportation revenue is included in the Partnership s equity income from Great Lakes during the same period. At December 31, 2007, $10.0 million is included in Great Lakes receivables in regards to the transportation contracts with TransCanada and its affiliates.

For the year ended December 31, 2007, the Partnership recorded transmission revenues of $19.4 million in regards to various contracts with Sierra Pacific Power Company, a wholly-owned subsidiary of Sierra Pacific Resources.

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border. At the time of this transaction, the Partnership paid a $10.0 million transaction fee to TransCanada Northern Border related to the assumption of operatorship. This fee has been recorded as part of the Partnership s investment in Northern Border and is being amortized over the term of the related operating agreement partially offsetting equity income.

On May 8, 2007, the Partnership reimbursed TransCanada $2.8 million for third party costs related to the Partnership s acquisition of its interest in Great Lakes. On September 26, 2007, the Partnership reimbursed

TransCanada $1.2 million for a working capital adjustment related to the Partnership s acquisition of its interest in Great Lakes.

On December 31, 2007, the Partnership acquired a one per cent general partner interest in Tuscarora from a wholly-owned subsidiary of TransCanada for $2.0 million. The purchase price of this acquisition was derived from the formula used to calculate the purchase price of a separate one per cent general partner interest in Tuscarora which was purchased from Tuscarora Gas Pipeline Co. on the same day.

NOTE 14 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected financial data for the four quarters of each of 2007 and 2006.

Quarter ended (millions of dollars except per unit amounts)	Mar 31	Jun 30	Sep 30	Dec 31
2007				
Equity income	**24.8**	**23.4**	**30.4**	**31.6**
Transmission revenues	**6.9**	**6.7**	**6.7**	**6.9**
Net income	**20.0**	**17.7**	**24.6**	**26.7**
Net income per common unit	**$ 0.73**	**$ 0.45**	**$ 0.64**	**$ 0.70**
Cash distributions paid	**11.3**	**24.9**	**25.1**	**25.4**
2006				
Equity income	13.2	13.9	17.9	17.5
Transmission revenues				0.9
Net income	12.4	9.0	12.0	11.3
Net income per common unit	$ 0.67	$ 0.47	$ 0.65	$ 0.60
Cash distributions paid	10.7	10.8	10.7	11.3

NOTE 15 CAPITAL REQUIREMENTS

On April 30, 2007, the Partnership made a contribution of $7.5 million to Northern Border, representing the Partnership s 50 per cent share of a $15.0 million cash call issued by Northern Border. The funds were used by Northern Border to repay indebtedness.

Tuscarora incurred $13.2 million of capital expenditures during 2007, of which $12.2 million related to its compressor station expansion in Likely, California. These capital expenditures were funded with operating cash flows.

The Partnership contributed $3.1 million to Northern Border during 2006, representing its then 30 per cent share of a $10.3 million cash call issued by Northern Border. The funds were used by Northern Border to fund an expansion project.

NOTE 16 DERIVATIVE FINANCIAL INSTRUMENTS

The carrying value of cash and short-term investments, accounts receivable and other, accounts payable and accrued interest approximate their fair values because of the short maturity or duration of these instruments, or because the instruments carry a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership s long-term debt is estimated by discounting the future cash flows of each instrument at current borrowing rates.

The estimated fair values of the Partnership s and its subsidiary s long-term debt as of December 31, 2007 and 2006 are as follows:

	2007		2006	
(millions of dollars)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Senior Credit Facility	**507.0**	**507.0**	397.0	397.0
Series A Senior Notes	**54.5**	**58.7**	57.9	60.9
Series B Senior Notes	**5.5**	**6.0**	6.0	6.4
Series C Senior Notes	**6.4**	**7.0**	7.2	7.5
	573.4	**578.7**	468.1	471.8

The Partnership s short-term and long-term debt results in exposures to changing interest rates. The Partnership uses derivatives to assist in managing its exposure to interest rate risk.

At December 31, 2007, the fair value of the interest rate swaps and options accounted for as hedges was negative $9.8 million (2006 - positive $1.6 million). The fair value of interest rate swaps and options have been calculated using year-end market rates. The notional amount hedged was $475.0 million as at December 31, 2007 (2006 - $200.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $100.0 million of variable-rate debt is hedged by an interest rate option during the period from May 22, 2007 through May 22, 2009 to an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid will be 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility.

NOTE 17 ACCOUNTING PRONOUNCEMENTS

In 2006, the Financial Accounting Standards Board issued SFAS No. 157, *Fair Value Measurements,* and during 2007,issued SFAS No. 141(R), *Business Combinations - revised*, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115*, and SFAS No. 160, *Noncontrolling Interests in Consolidated financial Statements*.

SFAS No. 157 establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. The effect of adopting SFAS No. 157 is not expected to be material to our results of operations or financial position.

SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*. SFAS No. 141 (R) retains the fundamental requirements of SFAS No. 141 that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination, with the objective of improving the relevance and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. The requirements of this standard will not have a material impact on the results of the Partnership.

SFAS No. 159 permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. The effect of adopting SFAS No. 159 is not expected to be material to our results of operations or financial position.

SFAS No. 160 clarifies the classification of noncontrolling interests in consolidated statements of financial position and the accounting for and reporting of transactions between the reporting entity and holders of such noncontrolling interests. The Partnership does not have noncontrolling interests and therefore, is not affected by the changes resulting from this standard.

In June 2007 the Emerging Issues Task Force of the FASB issued EITF 07-4, Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share,* to Master Limited Partnerships . EITF 07-4 addresses how current period earnings of a Master Limited Partnership (MLP) should be allocated to the general partner, limited partners and when applicable, incentive distribution rights when applying the two-class method under Statement 128. A tentative conclusion was ratified by the FASB in December 2007. We are currently reviewing the applicability of EIFT 07-4 to our results of operations and financial position.

NOTE 18 SUBSEQUENT EVENTS

On January 17, 2008, the Board of Directors of the general partner declared the Partnership s 2007 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 14, 2008 to unitholders of record as of January 31, 2008, totaled $25.6 million and was paid in the following manner: $23.2 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $5.8 million to TransCan Northern as holder of 8,678,045 common units), $1.9 million to the general partner as holder of the incentive distribution rights, and $0.5 million to the general partner in respect of its two per cent general partner interest.

Great Lakes declared and paid a distribution of $25.0 million on February 1, 2008, of which the Partnership received its 46.45 per cent share or $11.6 million.

Northern Border declared and paid a distribution of $46.3 million on February 1, 2008, of which the Partnership received its 50 per cent share or $23.2 million.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners and Management Committee

Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary (partnership) as of December 31, 2007 and 2006, and the related consolidated statements of income and partners capital, and cash flows for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership s internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with U.S. generally accepted accounting principles.

The Partnership s consolidated financial statements for 2006 and 2005 were previously prepared as though the Partnership was a corporation and current income taxes and amounts equivalent to deferred income taxes were recorded in those financial statements. As more fully described in note 2 to the consolidated financial statements, the Partnership adopted a policy to exclude income taxes from the consolidated financial statements at the beginning of the current year. Consequently, the Partnership s consolidated financial statements for 2006 and 2005 have been restated to exclude income taxes.

/s/ KPMG LLP

Detroit, Michigan

January 22, 2008

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF INCOME AND PARTNERS CAPITAL

Years ended December 31 (Thousands of dollars)		**2007**	**2006 As Adjusted**	**2005 As Adjusted**
Transportation Revenues				
Affiliated Revenues	$	**137,166**	161,605	173,796
Nonaffiliated Revenues		**145,660**	110,652	106,947
		282,826	272,257	280,743
Operating Expenses				
Operation and Maintenance		**42,125**	34,083	41,312
Depreciation		**58,046**	57,612	57,693
Property and Other Non Income Taxes		**22,195**	25,965	26,756
		122,366	117,660	125,761
Operating Income		**160,460**	154,597	154,982
Other Income (Expense)				
Interest on Long Term Debt		**(35,096)**	(35,970)	(36,844)
Other, Net		**2,937**	3,704	1,897
		(32,159)	(32,266)	(34,947)
Net Income	$	**128,301**	122,331	120,035
Partners Capital				
Balance at Beginning of Year	$	**630,849**	640,617	674,409
Contributions by General Partners				30,976
Net Income		**128,301**	122,331	120,035
Distributions to Partners		**(193,500)**	(132,099)	(184,803)
Balance at End of Year	$	**565,650**	630,849	640,617

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

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED BALANCE SHEETS

As of December 31 (Thousands of dollars)		**2007**	**2006 As Adjusted**
ASSETS			
Current Assets			
Cash and Cash Equivalents	**$**	**31,960**	78,641
Accounts Receivable *(Net of allowance of $800 in 2007 and $1,000 in 2006)*		**29,229**	16,327
Receivable from Affiliates		**11,607**	18,954
Materials and Supplies		**11,257**	10,908
Prepayments		**3,424**	4,286
		87,477	129,116
Gas Utility Plant			
Property, Plant and Equipment		**2,045,133**	2,038,123
Less Accumulated Depreciation		**1,075,873**	1,030,059
		969,260	1,008,064
	$	**1,056,737**	1,137,180
LIABILITIES AND PARTNERS CAPITAL			
Current Liabilities			
Current Maturities of Long Term Debt	**$**	**10,000**	10,000
Accounts Payable		**26,468**	16,579
Payable to Affiliates		**1,871**	2,362
Property Taxes		**9,300**	17,793
Other Non Income Taxes		**3,645**	3,939
Accrued Interest		**9,143**	9,289
Other		**264**	4,136
		60,691	64,098
Long Term Debt		**430,000**	440,000
Other Liabilities		**396**	2,233
Partners Capital		**565,650**	630,849
	$	**1,056,737**	1,137,180

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

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 (Thousands of dollars)		2007	2006 As Adjusted	2005 As Adjusted
Cash Flow Increase (Decrease) from:				
Operating Activities				
Net Income	$	**128,301**	122,331	120,035
Adjustments to Reconcile Net Income to Operating Cash Flows:				
Depreciation		**58,046**	57,612	57,693
Allowance for Funds Used During Construction		**(438)**	(386)	(135)
Changes in Current Assets and Liabilities:				
Accounts Receivable		**(12,902)**	17,477	(2,516)
Receivable from Affiliates		**7,347**	(2,233)	(3,872)
Accounts Payable		**9,889**	(15,048)	6,631
Payable to Affiliates		**(491)**	(2,393)	1,767
Property and Other Non Income Taxes		**(8,787)**	(2,716)	341
Other		**(5,342)**	(3,309)	1,187
		175,623	171,335	181,131
Investing Activities				
Investment in Utility Plant		**(18,804)**	(18,953)	(16,102)
Insurance Proceeds			8,122	
		(18,804)	(10,831)	(16,102)
Financing Activities				
Repayment of Long Term Debt		**(10,000)**	(10,000)	(10,000)
Contributions by General Partners				30,976
Distribution to Partners		**(193,500)**	(132,099)	(184,803)
		(203,500)	(142,099)	(163,827)
Change in Cash and Cash Equivalents		**(46,681)**	18,405	1,202
Cash and Cash Equivalents:				
Beginning of Year		**78,641**	60,236	59,034
End of Year	$	**31,960**	78,641	60,236
Supplemental Disclosure of Cash Flow Information				
Cash Paid During the Year for Interest				
(Net of Amounts Capitalized of $184, $153 and $47, Respectively)	$	**35,294**	36,132	37,018

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

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

Great Lakes Gas Transmission Limited Partnership (Partnership) is a Delaware limited partnership that owns and operates an interstate natural gas pipeline system. The Partnership transports natural gas for delivery to wholesale customers in the Midwestern and northeastern United States and eastern Canada. The partners, their parent companies, and partnership ownership percentages at December 31 are as follows:

	Ownership %	
Partner (Parent Company)	**2007**	2006
General Partners:		
El Paso Great Lakes Company, LLC (El Paso Corporation)		46.45
TransCanada GL, Inc. (TransCanada Pipelines Limited)	**46.45**	46.45
TC GL Intermediate Limited Partnership (TC PipeLines, LP)	**46.45**	
Limited Partner:		
Great Lakes Gas Transmission Company (TransCanada Pipelines Limited - 2007 and El Paso Corporation and TransCanada Pipelines Limited - 2006)	**7.10**	7.10

On February 22, 2007 (acquisition date), TC PipeLines, LP (TCPL) and TransCanada Corporation (TransCanada) acquired El Paso Corporation s (El Paso) 46.45% ownership interest in the Partnership and 50% interest in Great Lakes Gas Transmission Company (Company), respectively.

The day-to-day operation of the Partnership activities is the responsibility of the Company pursuant to the Partnership s Operating Agreement with the Company. As of the acquisition date, the Company uses TransCanada and its affiliates to provide operating services. The Partnership is charged for the salaries, benefits and expenses of TransCanada and its affiliates for services attributable to its operations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary. GLGT Aviation Company owns a fractional interest in a transport aircraft used principally for pipeline operations. Intercompany amounts have been eliminated.

For purposes of reporting cash flows, the Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents. Under the Partnership s cash management system, the bank notifies the Partnership daily of checks presented for payment against its disbursement account. The Company transfers funds from short-term investments to cover the checks presented for payment. This system results in a book cash overdraft in the disbursement account as a result of checks outstanding. The book overdraft, which was reclassified to accounts payable, was $5.8 million and $0.3 million at December 31, 2007 and 2006, respectively.

The fair value of long term debt is discussed in footnote 4. All other financial instruments approximate fair value due to the short maturity of these instruments.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the use of estimates and assumptions that affect the amounts reported as assets, liabilities, revenues and expenses and the disclosures in these financial statements. Although management believes these estimates are reasonable, actual results could differ from those estimates.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, CONTINUED

Regulation

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership s accounting policies follow regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. There are no regulatory assets or liabilities reflected in these consolidated financial statements.

Revenue and Accounts Receivable

The Partnership generates transportation revenues based on transportation service contracts under a tariff regulated by the FERC. The tariff specifies maximum transportation rates and the contracts general terms and conditions of service. The majority of the service contracts are for firm service in which the customers pay a reservation fee for capacity on the pipeline system regardless of whether they actually utilize their reserved capacity. The Partnership recognizes reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. In addition to the reservation fee, a utilization fee is charged and the related revenue is recognized based on the volume of natural gas transported.

Accounts receivable are reported at the invoiced amount. The Partnership establishes an allowance for losses on accounts receivable if it is determined that all or a portion of the outstanding balance will not be collected. The Partnership also considers historical industry data and customer credit trends. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received differs from the scheduled amount of natural gas delivered or received. The Partnership values these imbalances due to or from customers and interconnecting pipelines at fair value. Imbalances are made up in kind, in accordance with the terms of the tariff.

Imbalances due from others are reported on the consolidated balance sheet as either accounts receivable or receivable from affiliates. Imbalances owed to others are reported on the consolidated balance sheet as either accounts payable or payable to affiliates. Imbalances are expected to settle within a year.

Materials and Supplies

Materials and supplies are valued at the lower of cost or market value with cost determined using the average cost method.

Gas Utility Plant and Depreciation

Gas utility plant is stated at cost and includes certain administrative and general expenses, plus an allowance for funds used during construction. The Partnership capitalizes major units of property replacements or improvements and expenses minor items. Planned major maintenance is accrued when, and only when, an obligating event occurs, and is recorded using the direct expensing method or the deferral method. The cost of plant retired is charged to accumulated depreciation net of salvage and cost of removal. Depreciation of gas utility plant is computed using the composite (group) method. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The Partnership s principal operating assets, which comprise approximately 98% of total property, plant and

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, CONTINUED

equipment, are depreciated at an annual rate of 2.75%. The remaining assets are depreciated at an annual rate ranging from 4% to 20%.

The allowance for funds used during construction represents the debt and equity costs of capital funds applicable to utility plant under construction, calculated in accordance with a uniform formula prescribed by the FERC. The rates used were 10.25%, 10.37%, and 10.50% for years 2007, 2006, and 2005, respectively.

Asset Retirement Obligations

In the fourth quarter of 2005, the Partnership adopted Financial Accounting Standards Board Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations.* FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing and/or amount of settlement of the obligations are uncertain. These conditional obligations were not addressed by SFAS No. 143, *Accounting for Asset Retirement Obligations,* which the Partnership adopted on January 1, 2003. FIN No. 47 requires accrual of a liability when a range of scenarios indicates that the potential timing and/or settlement amounts of conditional asset retirement obligations can be determined. The Partnership has asset retirement obligations if it were to permanently retire all or part of the pipeline system; however, the amount of asset retirement obligations cannot be reasonably estimated due to the inability to determine the scope and timing of asset retirements.

Impairment of Long-Lived Assets

The Partnership assesses its long-lived assets for impairment based on SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed the undiscounted cash flows expected to be generated by the asset. If the carrying amount exceeds the undiscounted cash flows, an impairment is recognized to the extent the carrying amount exceeds its fair value.

Accounting for Pipeline Integrity Costs

Prior to January 1, 2006, the Partnership capitalized certain costs incurred related to its pipeline integrity assessment programs as part of property, plant and equipment.

In June 2005, the FERC issued an order on *Accounting for Pipeline Assessment Costs* which generally requires that pipeline inspections and assessments incurred after January 1, 2006 be expensed. The Partnership expensed $3.3 million and $2.4 million of pipeline integrity costs in 2007 and 2006, respectively.

Change in Accounting Principle

In previously issued financial statements, the Partnership accounted for income taxes as if it were a corporation and recorded current income taxes and amounts equivalent to deferred income taxes in those financial statements. In 2007, the Partnership has concluded that a preferable accounting method is to exclude income taxes from its consolidated financial statements, as federal and most state income taxes are the responsibility of the partners.

The change in accounting principle is reported through retrospective application in accordance with SFAS No. 154, *Accounting Changes and Error Corrections.* The change in accounting principle increased 2007, 2006 and 2005 Operating Income and Net Income by $46 million, $44 million and $43 million, respectively. Cash flows from Operating Activities/Financing Activities increased/decreased by $41 million, $39 million and $33 million in 2007, 2006 and 2005, respectively. In addition, amounts equivalent to deferred income tax liabilities were removed and Partners Capital was increased by approximately $254

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, CONTINUED

million as of January 1, 2005, $264 million as of December 31, 2005, $269 million as of December 31, 2006, and $139 million as of December 31, 2007.

Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these consolidated financial statements. The Partnership is required, for FERC regulatory purposes, to account for income taxes as if it were a corporation. As a result, for purposes of determining Partners capital for regulatory accounting purposes, it is reduced by the amounts equivalent to the net deferred income tax liability balances.

As a result of the sale of the partnership interest, and a corresponding Internal Revenue Code Section 754 election, the pre-acquisition amounts equivalent to net deferred income tax liability balances were reduced by 46.45%. In addition, amounts equivalent to net deferred tax liabilities for pre-acquisition retirement plans were eliminated. As a result, Partners Capital and amounts equivalent to net deferred tax liabilities were adjusted on the acquisition date by approximately $135 million as approved by the FERC. Amounts equivalent to net deferred income tax liabilities were approximately $139 million and $269 million at December 31, 2007 and 2006, respectively, and are primarily related to accelerated depreciation on utility plant.

In the third quarter of 2007, the state of Michigan enacted the Michigan Business Tax (MBT), which replaces the Michigan Single Business Tax effective January 1, 2008. The MBT is an income tax levied at the partnership level. The MBT is expected to result in an annual income tax expense of approximately $4 to $5 million and to provide a property tax credit of approximately $1 million, for a net annual impact of $3 to $4 million beginning in 2008.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements , which provides guidance on measuring the fair value of assets and liabilities in the financial statements. Certain provisions are effective in 2008 and others in 2009. The effect of adopting SFAS No. 157 is not expected to be material to the consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115, which permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity shall report unrealized gains and losses in earnings, on items for which the fair value option has been elected, at each subsequent reporting date. SFAS No. 159 is effective for our fiscal year beginning January 1, 2008. The effect of adopting SFAS No. 159 is not expected to be material to the consolidated financial statements.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for prior years to conform to the current year presentation.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. AFFILIATED COMPANY TRANSACTIONS

Affiliated company amounts included in the Partnership s consolidated financial statements, not otherwise disclosed, are as follows:

Transportation Revenues (In thousands)		**2007**	**2006**	**2005**
TransCanada and affiliates	$	**135,629**	150,067	156,561
El Paso and affiliates		**1,537**	11,538	17,235

Affiliated transportation revenues are primarily provided under fixed priced contracts with remaining terms ranging from 1 to 10 years.

The Partnership reimbursed the Company and affiliates for salaries, benefits and other administrative and operating incurred expenses. Benefits include pension, defined contribution plans, and other post-retirement benefits. Operating expenses charged by the Company and affiliates in 2007, 2006, and 2005 were $26,836,000, $18,022,000 and $23,913,000, respectively.

The Company participated in El Paso sponsored pension and defined contribution plans until February 28, 2007. The Company also participated in a post-retirement health care plan. After the acquisition date, the Partnership is charged for benefit plan expenses and other benefits by a TransCanada affiliate through a benefit rate on labor costs.

4. DEBT

(In thousands)		**2007**	**2006**
Senior Notes, unsecured, interest due semiannually, principal due as follows:			
8.74% series, due 2008 to 2011	$	**40,000**	50,000
9.09% series, due 2012 to 2021		**100,000**	100,000
6.73% series, due 2009 to 2018		**90,000**	90,000
6.95% series, due 2019 to 2028		**110,000**	110,000
8.08% series, due 2021 to 2030		**100,000**	100,000
		440,000	450,000
Less current maturities		**10,000**	10,000
Total long term debt less current maturities	$	**430,000**	440,000

The aggregate estimated fair value of long term debt was $525,104,000 and $516,698,000 for 2007 and 2006, respectively. The fair value is determined using discounted cash flows based on the Partnership s estimated current interest rates for similar debt.

The aggregate annual required repayments of Senior Notes is $10,000,000 in 2008 and $19,000,000 for each year 2009 through 2012.

Under the most restrictive covenants in the Senior Note Agreements, approximately $237,000,000 of partners capital is restricted as to distributions as of December 31, 2007.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Management Committee

Northern Border Pipeline Company:

We have audited the accompanying balance sheets of Northern Border Pipeline Company (the Company) as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, cash flows, and changes in partners equity for each of the years in the three-year period ended December 31, 2007. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northern Border Pipeline Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Omaha, Nebraska
February 27, 2008

NORTHERN BORDER PIPELINE COMPANY

BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22,937	$ 10,997
Accounts receivable	31,307	30,073
Related party receivables	2,754	355
Materials and supplies, at cost	4,205	3,970
Prepaid expenses and other	1,506	1,118
Total current assets	62,709	46,513
Property, plant and equipment:		
In service natural gas transmission plant	2,485,607	2,488,765
Construction work in progress	2,876	2,522
Total property, plant and equipment	2,488,483	2,491,287
Less: Accumulated provision for depreciation and amortization	1,060,195	1,015,646
Property, plant and equipment, net	1,428,288	1,475,641
Other assets:		
Regulatory assets (Note 2)	20,638	19,144
Unamortized debt expense	2,662	3,284
Other	589	109
Total other assets	23,889	22,537
Total assets	$ 1,514,886	$ 1,544,691
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Current maturities of long-term debt (Note 6)	$	$ 170,000
Accounts payable	7,179	4,577
Related party payables	5,852	2,539
Accrued taxes other than income	27,625	27,571
Accrued interest	11,283	11,515
Other	1,487	1,511
Total current liabilities	53,426	217,713
Long-term debt, net of current maturities (Note 6)	615,286	449,844
Deferred credits and other liabilities		
Related party payables	2,260	
Regulatory liabilities (Note 2)	2,393	
Derivative financial instruments (Note 7)	1,852	
Other	1,616	2,099
Total deferred credits and other liabilities	8,121	2,099
Commitments and contingencies (Note 8)		
Partners equity:		
Partners capital	840,494	874,057
Accumulated other comprehensive income (loss)	(2,441)	978
Total partners equity	838,053	875,035
Total liabilities and partners equity	$ 1,514,886	$ 1,544,691

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

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF INCOME

	Years Ended December 31, 2007	2006	2005
	(In thousands)		
Operating revenue	$ 309,376	$ 310,900	$ 321,651
Operating expenses			
Operations and maintenance	54,057	49,500	39,506
Depreciation and amortization	60,733	58,721	58,052
Taxes other than income	29,379	31,541	31,345
Operating expenses	144,169	139,762	128,903
Operating income	165,207	171,138	192,748
Interest expense			
Interest expense	43,082	43,218	42,792
Interest expense capitalized	(11)	(137)	(157)
Interest expense, net	43,071	43,081	42,635
Other income (expense)			
Allowance for equity funds used during construction	30	192	269
Other income (Note 10)	2,427	2,218	2,396
Other expense (Note 10)	(488)	(622)	(532)
Other income, net	1,969	1,788	2,133
Net income to partners	$ 124,105	$ 129,845	$ 152,246

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31, 2007	2006	2005
	(In thousands)		
Net income to partners	$ 124,105	$ 129,845	$ 152,246
Other comprehensive income:			
Changes associated with hedging transactions	(3,419)	(1,284)	(1,500)
Total comprehensive income	$ 120,686	$ 128,561	$ 150,746

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

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2007	2006 (In thousands)	2005
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	$ 124,105	$ 129,845	$ 152,246
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	61,115	59,325	58,404
Allowance for equity funds used during construction	(30)	(192)	(269)
Changes in components of working capital	1,457	1,827	(127)
Other	(2,146)	(5,479)	(3,793)
Total adjustments	60,396	55,481	54,215
Net cash provided by operating activities	184,501	185,326	206,461
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	(10,636)	(20,857)	(28,555)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	15,000	10,330	
Distributions to partners	(172,668)	(178,841)	(202,901)
Issuance of debt	269,000	105,000	136,000
Retirement of debt	(273,000)	(112,000)	(109,000)
Debt financing costs	(257)		(321)
Net cash used in financing activities	(161,925)	(175,511)	(176,222)
Net change in cash and cash equivalents	11,940	(11,042)	1,684
Cash and cash equivalents at beginning of year	10,997	22,039	20,355
Cash and cash equivalents at end of year	$ 22,937	$ 10,997	$ 22,039
Supplemental disclosures for cash flow information:			
Cash paid for interest, net of amount capitalized	$ 44,481	$ 45,170	$ 44,067
Changes in components of working capital:			
Accounts receivable	$ (1,234)	$ 8,179	$ (5,694)
Related party receivables	(2,399)	1,939	(983)
Materials and supplies	(235)	(404)	(157)
Prepaid expenses and other	(388)	422	149
Accounts payable	2,602	(5,973)	6,491
Related party payables	3,313	(1,016)	(1,731)
Accrued taxes other than income	54	(66)	524
Accrued interest	(232)	(10)	160
Other current liabilities	(24)	(1,244)	1,114
Total	$ 1,457	$ 1,827	$ (127)

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

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF CHANGES IN PARTNERS EQUITY

	TC PipeLines Intermediate Limited Partnership	ONEOK Partners Intermediate Limited Partnership	Accumulated Other Comprehensive Income (Loss)	Total Partners Equity
	(In thousands)			
Partners equity at December 31, 2004	$ 289,014	$ 674,364	$ 3,762	$ 967,140
Net income to partners	45,674	106,572		152,246
Changes associated with hedging transactions			(1,500)	(1,500)
Distributions paid	(60,870)	(142,031)		(202,901)
Partners equity at December 31, 2005	273,818	638,905	2,262	914,985
Net income to partners	57,452	72,393		129,845
Changes associated with hedging transactions			(1,284)	(1,284)
Equity contributions received	3,099	7,231		10,330
Distributions paid	(80,420)	(98,421)		(178,841)
Ownership change	183,080	(183,080)		
Partners equity at December 31, 2006	437,029	437,028	978	875,035
Net income to partners	62,052	62,053		124,105
Changes associated with hedging transactions			(3,419)	(3,419)
Equity contributions received	7,500	7,500		15,000
Distributions paid	(86,334)	(86,334)		(172,668)
Partners equity at December 31, 2007	$ 420,247	$ 420,247	$ (2,441)	$ 838,053

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

NORTHERN BORDER PIPELINE COMPANY

NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

In this report, references to we, us or our collectively refer to Northern Border Pipeline Company.

We are a Texas general partnership formed in 1978. We own a 1,249-mile natural gas transmission pipeline system extending from the United States-Canadian border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana. In April 2006, ONEOK Partners Intermediate Limited Partnership (ONEOK Partners) completed the sale of a 20 percent partnership interest in us to TC PipeLines Intermediate Limited Partnership (TC PipeLines). As a result of the transaction, our General Partnership Agreement was amended and restated effective April 6, 2006.

The ownership and voting percentages of our partners at December 31, 2007 and 2006 are as follows:

Partner	**Ownership**
ONEOK Partners	50%
TC PipeLines	50%

We are managed by a Management Committee that consists of four members. Each partner designates two members, and TC PipeLines designates one of its members as chairman. The Management Committee designates the members of the Audit Committee, which consists of three members. One member is selected by the members of the Management Committee designated by the partner whose affiliate is the operator and two members are selected by the members of the Management Committee designated by the other partner.

The day-to-day management of our affairs is the responsibility of TransCanada Northern Border, Inc., (TransCanada Northern Border) pursuant to an operating agreement between us and TransCanada Northern Border effective April 1, 2007. TransCanada Northern Border utilizes the services of TransCanada Corporation (TransCanada) and its affiliates for management services related to us. We are charged for the salaries, benefits and expenses of TransCanada and its affiliates attributable to our operations. For the year ended December 31, 2007, our charges from TransCanada and its affiliates totaled approximately $22.5 million.

Prior to April 1, 2007, the day-to-day management of our affairs was the responsibility of ONEOK Partners GP, L.L.C. (ONEOK Partner GP) pursuant to an operating agreement between us and ONEOK Partners GP. ONEOK Partners GP also utilized ONEOK, Inc. (ONEOK) and its affiliates for management services related to us. We were charged for the salaries, benefits and expenses of ONEOK Partners GP, ONEOK and its affiliates attributable to our operations. For the years ended December 31, 2007, 2006, and 2005, our charges from ONEOK Partners GP and its current and former affiliates totaled approximately $9.3 million, $26.2 million and $20.1 million, respectively. Our 2007 charges include $3.6 million for transition related costs. See Note 8 for further discussion of transition related costs.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make assumptions and use estimates that affect the reported amounts of assets, liabilities, revenue and expenses as well as the disclosure of contingent assets and liabilities during the reporting period. Actual results could differ from these estimates if the underlying assumptions are incorrect.

Government Regulation

We are subject to regulation by the Federal Energy Regulatory Commission (FERC). Our accounting policies conform to 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 reflected on the balance sheets as regulatory assets and regulatory liabilities.

At December 31, 2007 and 2006, we have reflected regulatory assets of approximately $20.6 million and $19.1 million, respectively, on the balance sheets. These assets are being amortized, as directed by the FERC, over varying time periods up to 43 years.

The following table presents a summary of regulatory assets, net of amortization, at December 31, 2007, and 2006.

	December 31, 2007	December 31, 2006
	(In thousands)	
Fort Peck lease option	$ 10,797	$ 9,507
Pipeline extension project	6,459	6,920
Unamortized loss on reacquired debt	308	376
Deferred rate case expenditures	1,953	2,341
Compressor usage surcharge tracker	1,121	
Total regulatory assets	$ 20,638	$ 19,144

At December 31, 2007, we have reflected a regulatory liability of $2.4 million on the balance sheet related to negative salvage accrued for estimated net costs of removal of transmission plant. See the Property, Plant and Equipment and Related Depreciation and Amortization policy in this note for further discussion of negative salvage.

We assess the recoverability of costs recognized as regulatory assets and liabilities and the ability to continue to account for our activities based on the criteria set forth in SFAS No. 71, which includes such factors as regulatory changes and the impact of competition. Our review of these criteria currently supports the continuing application of SFAS No. 71. If we cease to meet the criteria of SFAS No. 71, a write-off of related regulatory assets and liabilities could be required.

Revenue Recognition

We transport gas for shippers under a tariff regulated by the FERC. The tariff specifies the maximum rates we may charge shippers and the general terms and conditions of transportation service on our pipeline system. We recognize revenue according to each transportation contract for transportation service that is provided to our customers. Customers with firm service transportation agreements pay a reservation fee for capacity on the pipeline system known as a reservation charge regardless of whether they actually utilize their reserved capacity. Firm service transportation customers also pay a fee known as a commodity charge that is based on the mileage and the volume of natural gas they transport. Customers with interruptible service transportation agreements may utilize available capacity on our pipeline after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges based on mileage and the volume of natural gas they transport. An allowance for doubtful accounts is recorded in situations where collectibility is not reasonably assured. We had no allowance for doubtful accounts at December 31, 2007 and 2006. We do not own the gas that we transport, and therefore we do not assume the related natural gas commodity price risk.

Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these financial statements. Our FERC tariff, through December 31, 2006, established the method of accounting for and calculating income taxes which would have been paid or accrued if we were organized during the period as a corporation. Pursuant to the terms of the settlement of our 2005 rate case, during the time period that the rates effective January 1, 2007 are in effect, the treatment historically accorded income taxes will be observed by us for regulatory accounting purposes.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

Property, Plant and Equipment and Related Depreciation and Amortization

Property, plant and equipment is stated at original cost. During periods of construction, we are permitted to capitalize an allowance for funds used during construction, which represents the estimated costs of funds used for construction purposes. The original cost of property retired is charged to accumulated depreciation and amortization. No retirement gain or loss is included in income except in the case of retirements or sales of entire regulated operating units or systems.

Maintenance and repairs are charged to operations in the period incurred. The provision for depreciation and amortization of the transmission line is an integral part of our FERC tariff. As a result of the settlement of our 2005 rate case, the effective depreciation rate applied to our transmission plant in 2007 is 2.40 percent. The effective depreciation rate applied to our transmission plant in 2006 and 2005 was 2.25 percent. The transmission plant depreciation rate in 2007 of 2.40 percent is comprised of two components: one based on economic service life or capital recovery and one based on cost of removal, net of salvage value received, or negative salvage. We accrue the estimated net costs of removal of transmission plant as a regulatory liability, which does not represent an existing legal obligation. The net cost of removal incurred on retirements of transmission plant is recorded as a reduction to the regulatory liability. As of December 31, 2007, $2.4 million for accrued negative salvage is included as a regulatory liability on the accompanying balance sheet. Composite rates are applied to all other functional groups of property having similar economic characteristics. See Note 4 for discussion of our 2005 rate case settlement.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received by a pipeline system or storage facility differs from the contractual amount of natural gas scheduled to be delivered or received. We value these imbalances due to or from shippers and interconnecting parties at an appropriate index price. Imbalances are made up in-kind, subject to the terms of our tariff.

Imbalances due from others are reported on the balance sheets as accounts receivable. Imbalances owed to others are reported on the balance sheets as accounts payable. All imbalances are classified as current.

Risk Management

We use financial instruments in the management of our interest rate exposure. A control environment has been established which includes policies and procedures for risk assessment and the approval, reporting and monitoring of financial instrument activities. We do not use these instruments for trading purposes. SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137 and SFAS No. 138, requires that all derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at their fair value. We determine the fair value of a derivative instrument by the present value of its future cash flows based on market prices from third party sources. We record changes in the derivative s fair value currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the income statement, and requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. See Note 7 for a discussion of our derivative instruments and hedging activities.

Unamortized Debt Premium, Discount and Expense

We amortize premiums, discounts and expenses incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Operating Leases

We have non-cancelable operating leases for office space and rights-of-way. We record rent expense over the lease term as it becomes payable. If operating leases include escalating rental payments, we determine the cumulative rental payments anticipated and recognize rent expense on a straight-line basis over the term of the lease.

Impairment of Long-Lived Assets

We assess our long-lived assets for impairment based on SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Contingencies

Our accounting for contingencies covers a variety of business activities including contingencies for legal exposures and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with SFAS No. 5, Accounting for Contingencies. We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

Reclassifications

Certain reclassifications have been made to the financial statements for prior years to conform to the current year presentation. These reclassifications did not impact previously reported net income or partners equity.

3. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. Effective December 31, 2005, we adopted FIN 47, Accounting for Conditional Asset Retirement Obligations an interpretation of SFAS No. 143. FIN 47 clarifies the term conditional asset retirement obligation, as used in SFAS No. 143 and the circumstances under which an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. We have determined that asset retirement obligations exist for certain of our transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system life is not determinable with the degree of accuracy necessary to currently establish a liability for the obligations.

4. RATES AND REGULATORY ISSUES

The FERC regulates the rates and charges for transportation of natural gas in interstate commerce. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline s actual prudent historical cost investment. The rates and terms and conditions for service are found in each pipeline s FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

As required by the provisions of the settlement of our 1999 rate case, on November 1, 2005 we filed a rate case with the FERC. In December 2005, the FERC issued an order that identified issues that were raised in the proceeding and accepted the proposed rates, but suspended their effectiveness until May 1, 2006. Beginning May 1, 2006, the new rates were collected subject to refund through September 30, 2006. Based on the settlement, discussed below, we refunded $10.8 million to our customers in the fourth quarter of 2006.

The settlement of our 2005 rate case was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on our system. Beginning in 2007, overall rates were reduced, compared with rates prior to the filing, by approximately 5 percent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dekatherm (Dth) is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The factors used in calculating depreciation expense for transmission plant were increased from 2.25 percent to 2.40 percent. The settlement also provided for seasonal rates for short-term transportation services. Seasonal maximum rates vary on a monthly basis from approximately $0.54 per Dth to approximately $0.29 per Dth for the full transportation route from Port of Morgan, Montana to the Chicago area. The settlement included a three-year moratorium on filing rate cases and participants challenging these rates, and requires that we file a rate case within six years from the date the new rates went into effect.

The compressor usage surcharge rate is designed to recover the actual costs of electricity at our electric compressors and any compressor fuel use taxes imposed on our pipeline system. Any difference between the compressor usage surcharge collected and the actual costs for electricity and compressor fuel use taxes is recorded as either an increase to expense for an over recovery of actual costs or as a decrease to expense for an under recovery of actual costs, and is included in operations and maintenance expense on the income statement and as either a regulatory liability or a regulatory asset, respectively, on the balance sheet. The compressor usage surcharge rate is adjusted annually. The regulatory liability or regulatory asset will reflect the net over or under recovery of actual compressor usage related costs at the date of the balance sheet. As of December 31, 2007, we had recorded $1.1 million as a regulatory asset on the accompanying balance sheet for the net under recovery of compressor usage related costs.

5. TRANSPORTATION SERVICE AGREEMENTS

Operating revenues are collected pursuant to the FERC tariff through transportation service agreements. Our firm service agreements at December 31, 2007, extend for various terms with termination dates that range from one day to approximately eight years. We also have interruptible transportation service agreements and other transportation service agreements with numerous shippers. Under the capacity release provisions of our FERC tariff, shippers under firm contracts are allowed to release all or part of their capacity either permanently for the full term of the contract or temporarily. A temporary capacity release does not relieve the original contract shipper from its payment obligations if the replacement shipper fails to pay for the capacity temporarily released to it.

At December 31, 2007, our largest shippers, Cargill Inc. (Cargill) and BP Canada Energy Marketing Corp. (BP Canada) were obligated for approximately 15 percent and 14 percent of summer day design capacity, respectively. The Cargill and BP Canada firm service agreements extend for various terms with termination dates ranging from March 2008 to December 2008 and January 2008 to April 2014, respectively.

For the year ended December 31, 2007, shippers providing significant operating revenues were BP Canada, Nexen Marketing U.S.A. Inc. (Nexen) and Cargill with revenues of $49.7 million, $44.1 million, and $42.0 million, respectively. For the year ended December 31, 2006, shippers providing significant operating revenues were BP Canada and Cargill with revenues of $66.7 million and $43.0 million, respectively. For the year ended December 31, 2005, shippers providing significant operating revenues were BP Canada, Nexen, EnCana Marketing (USA) Inc. and Cargill with revenues of $56.1 million, $38.1 million, $37.9 million and $34.1 million, respectively.

For the years ended December 31, 2007, 2006 and 2005, we had contracted firm capacity held by one shipper affiliated with one of our general partners. ONEOK Energy Services Company, LP (ONEOK Energy), a subsidiary of ONEOK, holds firm service agreements representing approximately 3 percent of summer day design capacity at December 31, 2007. The firm service agreements with ONEOK Energy extend for various terms with termination dates that range from March 2008 to November 2011. Revenue from ONEOK Energy for 2007, 2006 and 2005 was $5.1 million, $7.0 million and $7.7 million, respectively. At December 31, 2007 and 2006, we had outstanding receivables from ONEOK Energy of $0.8 million and $0.3 million, respectively.

6. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
2007 Credit Agreement - average interest rate of 5.35% at December 31, 2007 due 2012	$ 166,000	$
2005 Credit Agreement - average interest rate of 6.33% at December 31, 2006 refinanced in 2007		20,000
1999 Senior Notes 7.75%, due 2009	200,000	200,000
2001 Senior Notes 7.50%, due 2021	250,000	250,000
2002 Senior Notes 6.25%, due 2007		150,000
Unamortized debt discount, net of premium	(714)	(156)
Subtotal	615,286	619,844
Current maturities		(170,000)
Long-term debt	$ 615,286	$ 449,844

On April 27, 2007, we entered into a $250 million amended and restated revolving credit agreement (2007 Credit Agreement) with certain financial institutions. The 2007 Credit Agreement was used to refinance the outstanding indebtedness under our $175 million revolving credit agreement dated as of May 16, 2005 (2005 Credit Agreement) and was used to repay all of the $150 million of our 6.25 percent Senior Notes due May 1, 2007. The 2007 Credit Agreement can also be used to finance permitted acquisitions, pay related fees and expenses, issue letters of credit and provide for ongoing working capital needs and for other general business purposes, including capital expenditures.

At December 31, 2007, based on the principal commitment amount of $250 million, available capacity under the 2007 Credit Agreement was $84 million. We may, at our option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under our 2007 Credit Agreement by an aggregate amount not to exceed $100 million, provided that lenders are willing to commit additional amounts. At our option, the interest rate on the outstanding borrowings may be the lenders base rate or the London Interbank Offered Rate plus a spread that is based on our long-term unsecured credit ratings. The 2007 Credit Agreement permits us to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. We are required to pay a facility fee of 0.05 percent based on the principal amount of the commitment of $250 million. The term of the agreement is five years, with options for two one-year extensions.

Certain of our long-term debt arrangements contain certain covenants that restrict the incurrence of secured indebtedness or liens upon property by us. Under the 2007 Credit Agreement, we are required to comply with certain financial, operational and legal covenants. Among other things, we are required to maintain a ratio of total debt to EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges) of no more than 4.75 to 1. Pursuant to the 2007 Credit Agreement, if one or more acquisitions are consummated in which the aggregate purchase price is $25

million or more, the allowable ratio of total debt to EBITDA is increased to 5.50 to 1 for the first three full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2007 Credit Agreement may become immediately due and payable. At December 31, 2007, we were in compliance with all of our financial covenants.

Aggregate required repayments of long-term debt for the next five years are $200 million in 2009 and $166 million in 2012. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2008, 2010 or 2011.

The following estimated fair values of financial instruments represent the amount at which each instrument could be exchanged in a current transaction between willing parties. Based on quoted market prices for similar issues with similar terms and remaining maturities, the estimated fair value of the aggregate of the senior notes outstanding at December 31, 2007 and 2006, was approximately $493 million and $623 million, respectively. We presently intend to maintain the current schedule of maturities for the 1999 Senior Notes and the 2001 Senior Notes, which will result in no gains or losses on their respective repayments. The fair value of the 2007 Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

7. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Prior to the anticipated issuance of fixed rate debt, we entered into forward starting interest rate swap agreements. The interest rate swap agreements were designated as cash flow hedges as they hedged the fluctuations in Treasury rates and spreads between the execution date of the swap agreements and the issuance of the fixed rate debt. The notional amount of the interest rate swap agreements did not exceed the expected principal amount of fixed rate debt to be issued. Upon issuance of the fixed rate debt, the swap agreements were terminated and the proceeds received or amounts paid to terminate the swap agreements were recorded in accumulated other comprehensive income and amortized to interest expense over the term of the debt.

During the years ended December 31, 2007, 2006, and 2005, respectively, we amortized approximately $1.6 million, $1.3 million, and $1.5 million related to the terminated interest rate swap agreements as a reduction to interest expense from accumulated other comprehensive income. We expect to amortize approximately $1.5 million as a reduction to interest expense in 2008.

We record in long-term debt amounts received or paid related to terminated interest rate swap agreements for fair value hedges and amortize these amounts to interest expense over the remaining original term of the interest rate swap agreements. During the years ended December 31, 2007, 2006, and 2005, we amortized approximately $0.7 million, $2.1 million and $2.1 million, respectively, as a reduction to interest expense. Amounts received or paid related to terminated interest rate swap agreements for fair value hedges were fully amortized at June 30, 2007.

In August 2007, we entered into a zero cost interest rate collar agreement (the Collar Agreement) to limit the variability of the interest rate on $140 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 percent and a cap of 5.36 percent. We have designated the Collar Agreement as a cash flow hedge. At December 31, 2007, the balance sheet reflected an unrealized loss of approximately $1.9 million with a corresponding decrease to accumulated other comprehensive income (loss) related to the changes in fair value of the Collar Agreement since inception. Since inception, no amounts have been recognized in income due to ineffectiveness or amounts received or paid under the Collar Agreement.

8. COMMITMENTS AND CONTINGENCIES

Operating Leases

Future minimum lease payments under non-cancelable operating leases on office space and rights-of-way are as follows:

		(In thousands)
Year ending December 31,		
2008		2,540
2009		2,541
2010		2,194
2011		1,889
2012		1,889
Thereafter		61,072
	$	72,125

Expenses incurred related to these lease obligations for the years ended December 31, 2007, 2006 and 2005 were $1.5 million, $0.7 million, and $0.6 million, respectively.

In August 2004, we signed an Option Agreement and Expanded Facilities Lease (Option Agreement) with the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. The Option Agreement documented the settlement of certain pipeline and right-of-way lease and taxation issues. The Option Agreement grants to us, among other things: (i) an option to renew the pipeline right-of-way lease upon agreed terms and conditions on or before April 1, 2011, for a term of 25 years with a renewal right for an additional 25 years; (ii) a right to use additional tribal lands for expanded facilities; and (iii) release and satisfaction of all tribal taxes against us. In consideration of this option and other benefits, we paid a lump sum amount of $7.4 million and will make additional annual option payments of approximately $1.5 million through March 31, 2011.

Transition Related Costs

We are required to pay $3.6 million over a five year period under a transition services agreement between ONEOK Partners GP and TransCanada Northern Border, related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used or currently in use for our operations. During the second quarter of 2007 a charge of $2.3 million was recorded in operations and maintenance expense and $1.3 million was recorded as natural gas transmission plant for the shared equipment and furnishings previously used or currently in use by us, respectively. Amounts related to this obligation are included in related party payables on the balance sheet. Future remaining payments for this obligation are as follows:

Year ending December 31,	**(In thousands)**
2008	753
2009	753
2010	753

2011		753
	$	3,012

Environmental Matters

We are not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

Other

Various legal actions that have arisen in the ordinary course of business are pending. We believe that the resolution of these issues will not have a material adverse impact on our results of operations or financial position.

9. CASH DISTRIBUTION POLICY

Our General Partnership Agreement provides that distributions to our partners are to be made on a pro rata basis according to each partner s capital account balance. Our Management Committee determines the amount and timing of the distributions to our partners including equity contributions and the funding of growth capital expenditures. Any changes to, or suspension of, our cash distribution policy requires the unanimous approval of the Management Committee. Our cash distributions are equal to 100 percent of our distributable cash flow as determined from our financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. In 2006, upon the closing of the sale of a 20 percent general partnership interest in us from ONEOK Partners to TC PipeLines, our Management Committee adopted certain changes to our cash distribution policy related to financial ratio targets and equity contributions. The change defined minimum equity to total capitalization ratios to be used by the Management Committee to establish the timing and amount of required equity contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by equity contributions.

For the years ended December 31, 2007, 2006 and 2005, we paid distributions to our general partners of $172.7 million, $178.8 million and $202.9 million, respectively. In 2007, we issued an equity cash call to our general partners in the amount of $15.0 million for the previously approved 2007 equity cash call. The proceeds were used to repay indebtedness. We issued an equity cash call to our general partners of $10.3 million in 2006 to fund approximately 50 percent of our growth capital expenditures.

10. OTHER INCOME (EXPENSE)

Other income (expense) on the statements of income includes such items as investment income, nonoperating revenues and expenses, and nonrecurring other income and expense items. For the years ended December 31, 2007, 2006 and 2005, other income (expense) included:

	Years Ended December 31,		
	2007	2006	2005
	(In thousands)		
Other income			
Nonoperating revenue	$ 1,638	$ 1,086	$ 1,134
Investment income	691	627	487
Bad debt expense adjustment			408
Other	98	505	367
Other income	$ 2,427	$ 2,218	$ 2,396
Other expense			
Depreciation and amortization for non-regulated property	$ (382)	$ (604)	$ (351)
Other	(106)	(18)	(181)
Other expense	$ (488)	$ (622)	$ (532)

11. ACCOUNTING PRONOUNCEMENTS

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. SFAS No. 157 is effective for our fiscal year beginning January 1, 2008. The effect of adopting SFAS No. 157 is not expected to be material to our results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115, which permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity shall report unrealized gains and losses in earnings, on items for which the fair value option has been elected, at each subsequent reporting date. SFAS No. 159 is effective for our fiscal year beginning January 1, 2008. The effect of adopting of SFAS No. 159 is not expected to be material to our results of operations or financial position.

12. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $46.3 million was declared and paid on February 1, 2008 for the fourth quarter of 2007.