TC PIPELINES LP
Form 10-K
February 27, 2009
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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, 2008

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 No.)**
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:

Common units representing limited partner interests	**NASDAQ Stock Market**
Title of each class	**Name of each exchange on which registered**

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

None

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

Yes o No x

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 accelerated 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 **(Do not check if a small reporting company)**	**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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as at June 30, 2008 was approximately $850.6 million.

As of February 27, 2009, there were 34,856,086 common units of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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

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Glossary

The abbreviations, acronyms, and industry terminology used in this annual report are defined as follows:

2007 Credit Agreement	Northern Border s $250.0 million amended and restated revolving credit agreement
ANR	ANR Pipeline Company
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BIA	Bureau of Indian Affairs
Bison Project	Bison Pipeline Project
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFATS	Chemical Facility Anti-Terrorism Standards
CWA	Clean Water Act
Collar Agreement	Northern Border s zero cost interest rate collar agreement
DCF	Discounted cash flow
Dth	Dekatherms
Dth/d	Dekatherms per day
EBITDA	Net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest Corporation
INGAA	Interstate Natural Gas Association of America
IRS	Internal Revenue Service
LDCs	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
MBT	Michigan Business Tax
MLP	Master Limited Partnership
MMcf/d	Million cubic feet per day
NEPA	National Environmental Policy Act
Net WCSB Flows to Markets	Net of WCSB production less WCSB demand that is available for transportation to downstream markets
NGA	Natural Gas Act
Northern Border	Northern Border Pipeline Company
NOV	Notice of Violation
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners GP	ONEOK Partners GP, LLC
Our pipeline systems	Great Lakes, Northern Border and Tuscarora
Partnership	TC PipeLines, LP and its subsidiaries
RCRA	Resource Conservation and Recovery Act
REX	Rockies Express Pipeline
REX East	Eastern segment of the Rockies Express Pipeline
REX West	Western segment of the Rockies Express Pipeline
ROE	Return on equity
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines revolving credit and term loan agreement
SFAS	Statement of Financial Accounting Standards
Sierra Pacific Power	Sierra Pacific Power Company, a subsidiary of NV Energy Inc. (formerly known as Sierra Pacific Resources)
TC PipeLines	TC PipeLines, LP and its subsidiaries
TC PipeLines GP	TC PipeLines GP, Inc.

TCNB	TransCanada Northern Border Inc., a wholly-owned subsidiary of TransCanada
TransCan Northern	TransCan Northern Ltd., a wholly-owned subsidiary of TransCanada

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TransCanada	Collectively, TransCanada Corporation and its wholly-owned subsidiary, TransCanada PipeLines Limited
TSA	Transportation Security Administration
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

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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 Gas Transmission Limited Partnership (Great Lakes) and Northern Border Pipeline Company (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;
  - level of natural gas basis differentials;
  - competitive conditions in the overall natural gas and electricity markets;
  - availability of supplies of Canadian and United States (U.S.) natural gas, including the newly discovered natural gas developments such as the Horn River and Montney shale gas developments in Western Canada, U.S. Rockies and U.S. Mid-Continent shale gas developments, and the Marcellus shale gas developments;
  - availability of additional storage capacity and current storage levels;
  - level of liquefied natural gas (LNG) imports;
  - weather conditions that impact supply and demand;
  - ability of shippers to meet credit worthiness requirements; and
  - competitive developments by Canadian and U.S. natural gas transmission companies;
- changes in relative cost structures of natural gas producing basins, such as changes in royalty programs, that may prejudice the development of the Western Canada Sedimentary Basin (WCSB);
- the decision by other pipeline companies to advance projects which will affect our pipeline systems and the regulatory, financing and construction risks related to construction of interstate natural gas pipelines;
- the successful completion, timing, cost, scope and future financial performance of our pipeline systems expansion projects could differ materially from our expectations due to availability of contractors or equipment, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages, expansion costs that are higher than anticipated and numerous other factors beyond our control;
- performance of contractual obligations by customers of our pipeline systems;
- the imposition of entity level taxation by states on partnerships;
- 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 Federal Energy Regulatory Commission (FERC) regulations, on us and our pipeline systems;
- our ability to control operating costs; and
- prevailing economic conditions, including the current uncertainty in the global economic markets, which impact the debt and equity capital 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 are made only as of the date of the filing of this report, and except as

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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 North American energy infrastructure businesses. To date, our primary focus has been in the transportation of natural gas from the WCSB to a variety of downstream markets.

TC PipeLines, LP and its subsidiaries 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.

The global economic slowdown is anticipated to have a short-term impact on demand for all forms of energy, including natural gas. However, when the economy returns to a growth cycle, North America s demand for natural gas is expected to increase.

Our pipeline investments are underpinned by contracts, regulation and strong business fundamentals. Customer demand for the transportation services our pipeline systems provide is directly related to the demand for natural gas in the markets served by our pipeline systems. Although North American demand for natural gas has recently declined and is expected to further decline in 2009 with the current economic downturn, we expect the demand to increase in the long-term.

Our strong financial position, including an available unused credit facility, gives us the capacity to pursue opportunities to grow in a sustained and disciplined manner for the long-term benefit of our unitholders.

Our current portfolio of interstate natural gas pipeline investments in the U.S. consists of:

- A 100 per cent general partner interest in Tuscarora Gas Transmission Company (Tuscarora). The final two per cent general partner interest was purchased in December 2007.
- A 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). This interest was purchased in February 2007 from El Paso Corporation. 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.

TransCanada operates Great Lakes, Northern Border and Tuscarora (collectively, our pipeline systems). See Item 13. Certain Relationships and Related Transactions, and Director Independence .

Year in Review 2008

Northern Border Expansion Project Commencement In September 2008, Northern Border commenced construction on its interconnect expansion project to support Northern States Power s request for firm backhaul service from a receipt point interconnection with ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada, to an existing delivery point at Ventura, Iowa (Des Plaines Project). The Des Plaines Project is estimated to cost approximately $18.0 million and was placed into service in late February 2009.

Northern Border Sale of Subsidiary In August 2008, Northern Border sold its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada PipeLine USA Ltd., a wholly-owned subsidiary of TransCanada, for $20.0 million. In

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connection with this transaction, Northern Border recognized a gain on sale of $16.2 million. TC PipeLines received a special distribution of $8.2 million in the third quarter of 2008 related to this transaction.

As part of the transaction, TransCanada has assumed the obligations of Northern Border related to the proposed Bison pipeline system (Bison Project), and continues to work with the Bison Project shippers to finalize the size and design of this project. The assets and obligations of Bison Pipeline LLC included executed precedent agreements, subject to certain shipper contingencies, as well as regulatory, environmental and engineering activities completed to date.

The proposed Bison Project would extend from natural gas gathering facilities located in the Powder River Basin in Wyoming to a point of interconnection with the Northern Border system in Morton County, North Dakota. The project has shipping commitments for approximately 407 million cubic feet per day (MMcf/d) and is projected to go into service late 2010. Shippers on the Bison Project have executed contracts for capacity on the Northern Border system from Port of Morgan, Montana to Ventura, Iowa, subject to the in-service date of the Bison Project. Project subscription that is subject to the upstream capacity condition is approximately 407 MMcf/d.

Tuscarora Expansion Project Completion On April 1, 2008, Tuscarora s compressor station expansion project to support Sierra Pacific Power Company s (Sierra Pacific Power s) Tracy Combined Cycle Power Plant went into service. Sierra Pacific Power is a subsidiary of NV Energy Inc. (formerly known as Sierra Pacific Resources).

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.

We seek opportunities to undertake accretive acquisitions and pursue organic growth projects to maximize the value of our existing portfolio of pipeline systems. Working with our partners 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.

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 links for the transportation of natural gas from the Alberta Hub in Canada 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 Montney and Horn River shale deposits in Western Canada, the Mackenzie Delta in Northern Canada and Alaska are constructed;

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

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- 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

One of our principal strengths is our relationship with TransCanada. TransCanada, a Canadian corporation, was founded in 1951 with the objective of transporting natural gas from Alberta to distant markets. Today, TransCanada is a major North American energy infrastructure company engaged in numerous aspects of the energy industry but is primarily focused on natural gas transmission and power generation services. TransCanada owns approximately 36,500 miles of wholly-owned natural gas pipelines, interests in an additional 4,800 miles of natural gas pipelines, approximately 370 Bcf of storage capacity and, including facilities that are under construction or in development, also owns, operates, and/or controls approximately 10,900 megawatts of power generation. Also, currently under construction is Keystone, an oil pipeline consisting of 2,147 miles of pipe that will initially transport crude oil from Hardisty, Alberta, Canada to U.S. Midwest markets and to Cushing, Oklahoma.

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.

See Item 5.   Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities   for more information regarding TransCanada s ownership in us.

Our Pipeline Systems

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All of our pipeline systems are 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. The FERC also governs the general terms and conditions for natural gas transportation service on interstate natural gas pipelines. 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.

Transportation Services

Our pipeline systems transportation contracts include specifications regarding the receipt and delivery of natural gas at points along the pipeline system. The transportation services provided by our pipeline systems are generally categorized as firm or interruptible. 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 based on 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. On Great Lakes system, interruptible and overrun revenues in excess of $0.5 million are generally subject to a sharing mechanism whereby 90 per cent of the revenue is refunded to firm shippers paying maximum tariff rates. The table below provides information with respect to tariff revenue composition for each of our investments for the year ended December 31, 2008. The weighted average remaining contract life is determined as at January 31, 2009.

		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%	2.7
Northern Border	50%	89%	8%	3%	2.1
Tuscarora	100%	100%	n/a	0%	11.6

(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 its tariff.

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

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. We own 46.45 per cent of Great Lakes. TransCanada owns the remaining 53.55 per cent and is also the operator.

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Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes primary receipt point is with 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. Great Lakes also delivers gas to other storage systems and interconnects with other interstate natural gas pipelines.

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 day capacity of 2,300 MMcf/d during the summer and 2,500 MMcf/d during the winter. Annual capacity is determined by the summer design day capacity. Great Lakes has 14 compressor stations with a total of 438,000 horsepower and measurement facilities to support the 58 receipt and delivery points on the system.

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.

The major policies of Great Lakes are established by the management committee of Great Lakes (GL Management Committee). The current 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 (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.

Business of Northern Border

Northern Border is a Texas general partnership formed in 1978. TC PipeLines and ONEOK Partners each own a 50 per cent interest in Northern Border.

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 11 receipt and 52 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.

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

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 $18.0 million and be financed by a combination of debt and equity. Construction commenced in September 2008. The project was placed into service in late February 2009. The Des Plaines Project is fully subscribed under a long-term compression and transportation contract. The term of the contract commences with the in service date of the project and ends March 31, 2027, with estimated annual revenues of $3.0 million.

Business of Tuscarora

Tuscarora is a Nevada general partnership formed in 1993. TC PipeLines owns 100 per cent of Tuscarora.

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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 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 230 MMcf/d. Tuscarora has three compressor stations with a total of over 17,100 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, 2005 and 2008.

2008 Expansion Project - In July 2007, Tuscarora received FERC approval for the construction of a compressor station and related facilities. The project was placed into service on April 1, 2008. The approximately $20.4 million project was underpinned by a 22.5 year long-term contract with Sierra Pacific Power to supply its Tracy Combined Cycle Power Plant. The contract is expected to generate approximately $5.8 million of annual revenue.

NATURAL GAS INDUSTRY OVERVIEW

North American Demand

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.

Natural gas demand fluctuates on an annual basis as a result of the factors described above. Although North American demand for natural gas has declined recently and is expected to continue to decline in 2009 with the current economic downturn, we expect the demand to decline only in the short-term. The impact to demand for natural gas transportation service on any one pipeline system will depend upon changes in demand in the market areas which that pipeline serves.

Other 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;
- the relative transportation rates; and
- the volume of natural gas delivered to the markets supplied by that system from other supply sources and storage facilities.

Our pipeline systems are exposed to business risk when they are marketing their available capacity. This occurs when existing transportation contracts expire and there is available capacity on the pipeline system. Customers can then, depending on the market, either renegotiate their contract commitments, including shorter terms and discounted rates, or they may choose not to renew their contract. 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.

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Our Pipeline Systems

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

Year Ended December 31 Average Throughput (MMcf/d)	2008	2007	2006
Great Lakes (1)	**2,143**	2,270	2,236
Northern Border	**2,041**	2,247	2,246
Tuscarora	**82**	77	77

(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.

Great Lakes provides transportation services to Midwest and Northeast U.S. markets, as well as Eastern Canadian markets. Demand for natural gas in these markets has remained relatively consistent over the last three years and is expected to increase over the long-term, particularly to meet the expected growth in natural gas fired power generation. However, we believe the current economic environment could reverse this trend in the short-term. The demand for transportation on Great Lakes is mainly from local distribution companies (LDCs) and industrial customers, as well as for transportation of volumes back into Canada. Throughput on Great Lakes was down slightly in 2008 relative to 2007 and 2006 primarily due to underutilization of firm contracts.

Northern Border provides transportation services to Midwest U.S. markets directly and through major interconnections with other interstate natural gas pipelines. Demand for natural gas in these markets has been relatively flat over the past three years and is expected to grow over the long-term. The current economic environment may cause a decline in 2009 natural gas demand in this market area, but is expected to increase in the long-term. Demand for transportation on Northern Border remained relatively constant until 2008 when a drop in demand occurred related to new volumes of natural gas delivered to its markets from the Rockies natural gas basin by a competitive pipeline. This is discussed further under Customers, Competition and Contracting .

Tuscarora provides transportation services to markets in Oregon, Northern California and Northern Nevada. Demand for natural gas in these markets has grown over the last three years due primarily to increased demand from electric generation companies and LDCs. The major customers on Tuscarora s system require transportation capacity to meet their obligations to their customers but are not necessarily required to flow any gas through the system. As a result, Tuscarora s throughput is not indicative of its revenue generation. This is discussed further under Customers, Competition and Contracting .

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. In the spring and fall, when there is less demand for heating and cooling requirements, gas is put in storage near industrial consuming areas for future use. Available storage capacity combined with price spreads between current and future pricing during certain periods of the year may make it more profitable to store the gas for use in the future when the price for natural gas may be more favorable.

Seasonal fluctuations in demand for natural gas between market regions will also impact supply available to a given market area.

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. Revenues of 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

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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, Manitoba receipt point is approximately 2.5 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 storage areas. This is due to the approximate 880 Bcf of working gas storage located at the Eastern 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 normally 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 heating demand requirements of Northern Minnesota, Northern Wisconsin, and Michigan. These deliveries are met through Great Lakes short haul, long haul, and backhauls from storage. Approximately 13 per cent of Great Lakes flows were contracted on a short-term basis in 2008.

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 transportation during certain winter periods.

Northern Border Seasonal supply and demand fundamentals are a growing influence on Northern Border s system 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. Approximately 24 per cent of Northern Border s design capacity was contracted on a short-term basis in 2008. 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. Moderate winter and summer temperatures can lead to a decline in the demand for Northern Border s service due to reduced demand for natural gas.

Northern Border s settlement of its 2005 rate case 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.

Tuscarora Tuscarora is fully contracted under long-term contracts (100 per cent contracted with a weighted average remaining contract life of 11.6 years) at January 31, 2009, with approximately two per cent of its design capacity uncontracted beginning in the second quarter of 2009. 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. In 2008, approximately 80 per cent, 79 per cent and 97 per cent of the natural gas transported by Great Lakes, Northern Border and Tuscarora, respectively, was produced in Canada. For this reason, the continuous supply of Canadian natural gas is crucial to the long-term financial condition of our pipeline systems.

The WCSB has 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. However, supply from the WCSB has declined in recent years due to a continued reduction in drilling activity in the basin. Drilling in the WCSB is expected to reach a low point in 2009 and begin to recover in the ensuing years assuming that gas prices stabilize and that finding and development costs decrease.

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The net amount of WCSB natural gas flows available for downstream markets is the most significant factor affecting the volume of natural gas transported by our pipeline systems. Net WCSB flows to markets is the term we use to represent the net of the supply of and demand for WCSB natural gas. WCSB supply is made up of WCSB production with injections into WCSB storage reducing net supply, and withdrawals from WCSB storage increasing supply. The net WCSB flows to markets are determined by:

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

The extent to which net WCSB flows to markets 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 downstream 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

Great Lakes receives natural gas primarily 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 receives natural gas from its connection with one of TransCanada s pipelines at the Canadian border near Monchy, Montana. Northern Border also transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana, which accounted for approximately 15 per cent of the natural gas Northern Border transported in 2008. 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

Our pipeline systems transport natural gas for a variety of customers including other natural gas pipelines, LDCs, industrial companies, electric power generation companies, natural gas producers, and natural gas marketers. Each type of customer has a different reason for using certain natural gas transportation services and routes. LDCs, industrial companies and electric power 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 to meet their obligations to their customers over the life of the contracts with their customers. 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 marketers typically use transportation services to capitalize on natural gas price volatility and therefore tend to contract for shorter terms, which increases their flexibility.

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 WCSB 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 segments. Various LDCs in Minnesota, Wisconsin and Michigan contract for transportation on Great Lakes to diversify and add Canadian gas to their supply mix. In addition, natural gas marketers and producers hold transportation capacity on Great Lakes, either directly or through the capacity release program, and use Great Lakes

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flexibility to deliver gas to markets, interconnecting pipelines and storage facilities along its system to maximize the value of their transportation contracts. Great Lakes customer profile is becoming more heavily weighted towards natural gas marketers and less towards producers and end users, such as industrial customers and LDCs; however, Great Lakes largest customer remains TransCanada.

For the year ended December 31, 2008, TransCanada and ANR contracts represented approximately 47 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 to their 2008 revenues.

Northern Border - Northern Border s customers include natural gas producers, marketers, industrial companies, LDCs and electric power generating companies. Northern Border s contract life has been declining and its customer profile over the past five years has been mainly comprised of natural gas producers and marketers.

For the year ended December 31, 2008, contracts with BP Canada Energy Marketing Corp. and Cargill Inc. represented approximately 13 per cent and 11 per cent, respectively, of Northern Border s revenue. Northern Border did not have any other customers contributing more than 10 per cent of their 2008 revenues.

Tuscarora - Tuscarora s main customers are a power generation company and an LDC, along with a variety of industrial, commercial, and other companies.

For the year ended December 31, 2008, contracts with Sierra Pacific Power and Southwest Gas Company represented approximately 75 per cent and 11 per cent, respectively, of Tuscarora s revenue.

Competition

Competition among natural gas pipelines is based primarily on transportation rates 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. Other pipelines access the WCSB and provide alternative routes for shippers to access markets served by our systems or take gas to markets not served by our pipeline systems. Additionally, supply sourced from other U.S. supply basins is transported by other pipelines into our pipeline systems market areas.

Other factors affecting the market include an increase in the number of new pipeline projects in the U.S., which may change the natural gas supply and demand competition in the markets served by our pipeline systems. This growth in natural gas infrastructure has, in the recent past, led to rising costs, both in labor and materials, associated with these new pipeline projects. However, this trend of rising costs may be reversed with the current economic environment.

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 WCSB to Midwest and Northeast U.S. markets and Eastern Canadian markets. Natural gas is transported by TransCanada from Western Canada to near Emerson, Manitoba. Great Lakes provides transportation from Emerson to the TransCanada system at St. Clair, Michigan. TransCanada transports the gas received at St. Clair to Dawn, Ontario and points further east. 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, or the Alliance Pipeline which also interconnects with the Vector Pipeline. 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 or via ANR s and Great Lakes pipelines.

Northern Border Northern Border s system competes for natural gas supply with other pipelines that transport WCSB natural gas to markets in the West, Midwest and East in North America. The pipeline systems that offer primary competition include Alliance Pipeline, Great Lakes, Gas Transmission Northwest, and other pipelines that interconnect with the TransCanada mainline for WCSB supply. Northern Border also competes with other pipelines that serve Northern Border s market areas. Most of these pipelines have access to natural gas storage facilities, and alternate sources of supply from the Rockies, the Mid-Continent, the Permian Basin and the Gulf Coast, as well as LNG. These pipeline systems that offer primary competition include Northern Natural Gas Company in Northern Border s Ventura, Iowa market area and Alliance Pipeline, ANR, Midwestern Gas Transmission Company and Natural Gas Pipeline of America in the Chicago market region.

The Rockies Express Pipeline (REX) is a 1,679 mile pipeline originating in Rio Blanco County, Colorado to Monroe County, Ohio. Northern Border is experiencing increased competition from the Western segment (REX West), which delivers gas from the Rockies basin to Audrian County, Missouri, in the market area served by Northern

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Border. REX West was placed into service in May 2008. Northern Border experienced a reduction in its throughput and decreased demand for available capacity in 2008 related to this increased competition.

The Eastern segment (REX East) of the REX system will move gas from Audrian County, Missouri to Monroe County, Ohio and is expected to alleviate some of the excess supply in the Midwest markets. REX has announced that the REX East segment is expected to be fully in service in the fourth quarter of 2009. The combination of growing supply from the Rockies and shale developments reaching the Chicago market region through new and available pipeline capacity and reductions in demand resulting from the economic crisis has the potential to maintain competitive pressures in the Midwest markets on WCSB sourced natural gas. Any reductions in flows on Northern Border to the Chicago market will impact supply and demand fundamentals at the Ventura market.

Furthermore, overall North American natural gas flows will be impacted by pipeline projects that are anticipated to be in service in 2009 to move additional supply volumes from the lower Mid-Continent to existing Gulf Coast infrastructure.

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

Contracting

Transportation contracts mature at varying times and for varying amounts of throughput capacity. 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 length 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. Customer liquidity and capital constraints can also impact the length of contracts. If market conditions are not favorable at the time of renewal, transportation capacity may remain available 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.

The weighted average remaining contract life as at January 31, 2009 for each of our pipeline systems is included earlier in Item I in the table in the Our Pipeline Systems section.

Great Lakes For the year ended December 31, 2008, Great Lakes average contracted capacity compared to average design capacity was near 100 per cent (106 per cent of summer design day capacity). Great Lakes has long-term firm transportation contracts for 88 per cent of its average design capacity, as at January 31, 2009. Approximately two per cent of contracted capacity will expire by December 31, 2009 in the absence of extensions or renewals of this capacity.

Northern Border - Northern Border s average contracted capacity compared to design capacity for the year ended December 31, 2008 was 90 per cent. Some of this capacity was sold at a discount to maximize overall revenue on the Port of Morgan, Montana to Ventura and Harper, Iowa portions of the pipeline. As of January 31, 2009, Northern Border had 60 per cent of its design capacity uncontracted beginning in the second quarter of 2009 through the remainder of 2009. 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, 2008 was 98 per cent. Tuscarora has firm transportation contracts for 100 per cent of its available capacity, as at January 31, 2009. This includes contracts with Sierra Pacific Power for approximately 75 per cent of the total available capacity, the majority of which expire on October 31, 2017.

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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 businesses, 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, filed with the FERC on July 31, 2000, was approved by FERC Order issued October 26, 2000, and was effective November 1, 2000. The settlement continued the then existing base tariff rates, and reduced Great Lakes depreciation rate on transmission plant from 3.00 per cent to 2.75 per cent. Great Lakes continues to operate under rates established in that settlement. 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 effective January 1, 2007. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border s system. The settlement also provided for seasonal rates for short-term transportation services. Pursuant to the terms of the settlement, there is a moratorium on the parties to the settlement of raising any proceeding regarding Northern Border s currently effective rates until January 1, 2010 and Northern

Border must file a rate case by no later than December 31, 2012.

Cost and Revenue Study, Tuscarora As a result of an obligation to file a cost and revenue study with the FERC, the Public Utilities Commission of Nevada and Sierra Pacific Power agreed to a settlement with Tuscarora, which was approved by the FERC in July 2006. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (Dth/d) beginning June 1, 2006 and included a moratorium on all rate actions before the FERC by any party to the settlement until May 31, 2010. The settlement includes a moratorium by the settlement parties on rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate.

Income Tax Allowance In December 2007, the FERC issued an 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 their 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) their 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 In July 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 (ROE) for natural gas and oil pipelines, which is used by pipelines to establish rates for services. On April 17, 2008, the FERC issued a policy statement (2008 Policy Statement) that allows master limited partnerships (MLPs) to be included in a proxy group used to determine a pipeline s ROE. The 2008 Policy

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Statement provides that there should be no cap on the level of distributions included in the current Discounted Cash Flow (DCF) methodology for MLPs, but there should be an adjustment to the long-term growth rate used to calculate DCF for an MLP (halving the long-term GDP factor which has a one-third weighting in the total growth rate computation in the DCF methodology). On January 15, 2009, the FERC applied its policy statement in an order rejecting a contested Kern River Gas Transmission settlement in Docket No. RP04-274, finding that the 12.50 per cent return on equity in the settlement rates was excessive based on 2004 market data and would result in unjust and unreasonable rates. The FERC determined that Kern River s ROE should be 11.55 per cent, which was set at the median of a proxy group that included, for the first time in a litigated pipeline rate proceeding, both master limited partnerships and corporations.

The impact of applying this new policy to each of our pipeline systems will not be known until each pipeline system files a rate case.

Energy Affiliates In October 2008, the FERC issued Order No. 717, Standards of Conduct for Transmission Providers, which amended the regulations adopted on an interim basis in Order No. 690 to refocus the rules on the areas where there is the greatest potential for abuse; the day-to-day transmission transactions and operations that may involve marketing affiliates. This order identifies those affiliate relationships where there is the greatest potential and risk for undue discrimination and preference between a natural gas pipeline company and their marketing affiliates. The rule subjects the natural gas pipeline company to certain restrictions to function independently and not act as a conduit of transmission information to a marketing affiliate.

Promotion of a More Efficient Capacity Release Market Docket No. RM08-1 On June 19, 2008, the FERC issued a Final Rule to modify capacity release regulations (Capacity Release Final Rule). The Capacity Release Final Rule, in addition to other items, allows market-based pricing for short-term capacity releases by shippers through a permanent lifting of the maximum rate cap on short-term capacity releases (of one year or less terms). The Capacity Release Final Rule was effective July 30, 2008.

While implementation of the Capacity Release Final Rule is not expected to have a significant impact on our pipeline systems, the Interstate Natural Gas Association of America (INGAA), of which our pipeline systems are members, filed on July 21, 2008 a request for rehearing of the Capacity Release Final Rule, contending that as the FERC removed the rate cap for short-term released capacity, it should also remove the rate cap for short-term pipeline capacity. INGAA notes that short-term released capacity and short-term pipeline capacity compete in the same market, and argues that removing the rate cap for short-term released capacity and maintaining the cap for short-term pipeline capacity results in a bifurcated and distorted short-term capacity market. On November 21, 2008, the FERC issued Order No. 712-A addressing requests for clarification and rehearing. In that order, the FERC denied INGAA s request for rehearing and continued to maintain that the maximum rate ceilings for pipeline short-term transactions is necessary to protect against the potential exercise of market power. On January 15, 2009, INGAA filed an appeal of FERC s order with the U.S. Court of Appeals-D.C. Circuit.

Compliance with Statutes, Regulations, and Orders Docket No. PL09-1-000 On October 16, 2008, the FERC issued a Policy Statement on Compliance to provide additional guidance to the public on compliance with governing statutes, regulations and orders. The policy statement sets forth the following factors which will be considered when deciding to reduce or eliminate civil penalties for violations: 1) the role of senior management in fostering compliance; 2) effective preventive measures to ensure compliance; 3) prompt detection, cessation, and reporting of violations; and 4) remediation efforts.

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

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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. Inspection of the remaining 50 per cent of high consequence areas as mandated by regulation is expected to be completed, as required, by 2012.

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.

On February 2, 2009, Northern Border received a Notice of Violation from the United States Environmental Protection Agency alleging that Northern Border was in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on its system. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty, but does not expect such amounts to be material to its financial condition.

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 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

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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 The U.S. Congress or other federal government agencies may create legislation or regulations to reduce emissions of greenhouse gasses. 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.

Homeland Security The Department of Homeland Security Appropriations Act of 2007 required the Department of Homeland Security to issue regulations under the Chemical Facility Anti-Terrorism Standards (CFATS) establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that were deemed to present high levels of security risk. Our pipeline systems are not subject to the requirements of these regulations under CFATS.

The Transportation Security Administration (TSA) began in January 2009 a critical facility identification process of pipeline systems, which will include our pipeline systems. The TSA has released a second draft of the Pipeline Security Guidelines, which is likely to become regulation in 2009 or 2010. These guidelines distinguish between baseline security requirements for all pipeline facilities and enhanced measures for identified critical facilities. If our pipeline systems are deemed to be critical facilities, we do not anticipate additional costs related to compliance based on current draft guidelines.

Title to Properties

Our pipeline systems hold all rights, titles and interests in their respective pipeline systems. 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 the Bad River Chippewa Indian Reservation in Wisconsin. In 1968, Great Lakes obtained right-of-way across allotted lands located within each of the reservation s 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 1,000 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, with 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.

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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 our pipeline systems, in addition to providing services to the Partnership.

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 Securities and Exchange Commission (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 below, 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.

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. 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.*

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.

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

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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.

The recent global economic and financial market crisis has had and may continue to have a negative effect on our business.

The recent global economic and financial market crisis has caused, among other things, a general tightening in the credit markets, lower levels of liquidity, increases in the rates of default and bankruptcy, lower consumer and business spending, lower consumer net worth, and reduced energy demand. As a result of the continued economic weakness, there has been less demand for natural gas by residential, industrial and other users, which could have a negative effect on the business of our pipeline systems and our results of operations, financial condition and liquidity. Many natural gas producers, natural gas marketing companies, and end users have been negatively affected by the current economic conditions. Current or potential shippers may be unable to fund contracts or meet the creditworthiness requirements of our pipeline systems or they may reduce the amount or length of their transportation commitments on our pipeline systems, all of which could impact demand for transportation services on our pipeline systems, and may cause reduced revenue and increased customer payment delays or defaults. We are also limited in our ability to reduce costs to offset the results of a prolonged or severe economic downturn given the high percentage of fixed costs associated with our operations.

The timing and nature of any recovery in the credit and financial markets remains uncertain, and there can be no assurance that market conditions will improve in the near future or that our results will not be materially and adversely affected. Such conditions make it difficult to forecast operating results, make business decisions and identify and address material business risks. The foregoing conditions may also impact the valuation of certain long-lived or intangible assets, including goodwill, that are subject to impairment testing, potentially resulting in impairment charges which may be material to our financial condition or results of operations.

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If we do not identify opportunities for accretive growth through organic growth 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 and integrate 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. The current slowdown of the economy and restricted capital markets are negatively impacting development of natural gas reserves, which is expected throughout 2009.

Net WCSB flows to markets 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 downstream markets. 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 development of newly discovered natural gas plays such as the Montney and Horn River shale plays in Western Canada. Cancellation or delays in the construction of such pipelines or such projects could adversely affect the net WCSB flows to markets 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.

Customers may not extend their contracts or contract for transportation 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 two phases and the planned terminus is in Clarington, Ohio. REX West is completed and is currently delivering gas to interconnects in the Midwest region. The full in-service of REX West in May 2008 has resulted in significant downward pressure on natural gas prices in the Mid-Continent Region, and is having a negative impact on demand for Northern Border s transport and as REX extends east it may have an impact on Great Lakes in the future.

REX East is planned to extend from Audrain County, Missouri to Clarington in Monroe County, Ohio. Once in-service, REX East could improve the competitive position of Canadian supply with Mid-Continent sourced gas, potentially mitigating some of the excess supply in the Mid-Continent market. REX East will compete in some of Great Lakes markets, but will also potentially create demand for Great Lakes transportation of natural gas from REX East seeking access to and from storage locations in Michigan. It is now anticipated that the partial in-service and full in-service of REX East will occur in the second and fourth quarters of 2009, respectively. Although there can be no assurance on the timing or impact of REX East, we believe that any positive impact for Northern Border in the market it serves will not occur until 2010.

An increase in competition in the key markets served by our pipeline systems could arise from new ventures or expanded operations from existing competitors. The combination of growing supply from the Rockies and shale developments reaching the Chicago market region through both new and available pipeline capacity and demand

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destruction from the economic crisis has the potential to maintain competitive pressures on WCSB supply into the Midwest. Northern Border is fully contracted on its Eastern system that deliveries gas to Chicago; however, any reduction in flows to this market will impact the supply and demand fundamentals at the Ventura market.

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 business, financial position, results of operations, and ability to make distributions.

Our pipeline systems may not be able to maintain existing customers or acquire new customers when the current shipper contracts expire or customers may 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;
- the liquidity and willingness of shippers to contract for transportation services; 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 lives of Great Lakes and Northern Border s contracts have generally declined over time. As of January 31, 2009, the weighted average remaining lives of Great Lakes and Northern Border s contracts were 2.7 years and 2.1 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.

At any time, each of our pipeline systems may have 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 75 per cent of its capacity. NV Energy Inc. (formerly known as Sierra Pacific Resources) and its subsidiary, Sierra Pacific Power, have non-investment grade credit ratings.

Our pipeline systems are subject to regulation by agencies, including the FERC, which could have an adverse impact on our ability to establish transportation rates that would allow recovery of the full cost of operating our pipeline systems, including a reasonable return, and our ability to make distributions.

Under the Natural Gas Act (NGA), interstate transportation rates must be just, reasonable and not unduly discriminatory. Our pipeline systems are subject to extensive regulation by the FERC, the United States Department of Transportation, and other federal, state and local regulatory agencies. Regulatory actions taken by these agencies have the potential to adversely affect our pipeline systems profitability. Federal regulation extends to such matters as:

- 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;

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- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- income tax allowance policies;
- the acquisition and disposition of facilities;
- initiation and discontinuation of services;
- standards of conduct business relations with certain affiliates; and
- the integrity and safety of our pipeline systems and related operations.

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 preclude a party to the rate settlements from bringing any rate actions prior to December 31, 2009 and May 31, 2010, respectively. Northern Border is required to file a new rate proceeding before December 31, 2012.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our pipeline systems abilities 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 $1.0 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 collect from customers, as a result of a rate case, decreases as the rate base declines due to, among other things, depreciation and amortization.

Our pipeline systems pipeline integrity testing programs and any necessary pipeline repairs, or preventative or remedial measures may impose significant costs and liabilities.

The U.S. Department of Transportation has adopted regulations that require pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the regulations refer to as high consequence areas, where a leak or rupture could do the most harm. 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. Inspection of the remaining 50 per cent of high consequence areas as mandated by regulation is expected to be completed, as required, by 2012. After that point, the inspection of high consequence areas is required to reoccur every seven years. Once 100 per cent of our pipeline systems high consequence areas 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

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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. Additionally, any failure to comply with these regulations could subject our pipeline systems to penalties and fines. If these costs were significantly higher than estimated, our cash available for distribution may be correspondingly reduced.

Our pipeline systems operations are regulated by federal, state and local agencies responsible for environmental protection and operational safety, and costs of environmental compliance and the costs of environmental liabilities could exceed our estimates.

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, we may be required to obtain and maintain permits and approvals issued by various federal, state and local governmental authorities; limit or prevent releases of materials from our operations in accordance with these permits and approvals; and install pollution control equipment. Also, under certain environmental laws and regulations, we may be exposed to potentially substantial liabilities for any pollution or contamination that may result from our operations.

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. At this time, it is unclear what our pipeline systems future environmental compliance costs relating to greenhouse gases will be. Various federal and state legislative proposals have been made over the last several years and it is possible that legislation will be enacted in the future that could negatively impact the operations of our pipeline systems and our financial results. The level of such impact will likely depend upon whether any of our pipeline systems facilities will be directly responsible for compliance with any adopted program; whether cost containment measures will be available; the ability of our pipeline systems to recover compliance costs from their customers; and the manner in which allowances are provided. At the federal regulatory level, the U.S. Environmental Protection Agency (EPA) has requested public comments on the potential regulation of greenhouse gases under the Clean Air Act. It is uncertain whether the EPA will proceed with adopting final rules or whether the regulation of greenhouse gases will be addressed in federal and state legislation.

It is uncertain what impact these actions might have on our pipeline systems until further definition is known; there is risk that such future measures could result in changes to the operations of our pipeline systems and to the consumption and demand for natural gas. Changes to the operations of our pipeline systems could include increased costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; (iii) construct new facilities; and (iv) administer and manage any greenhouse gas emissions reduction program that may be applicable to our operations. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental compliance, including future compliance with greenhouse gas laws and regulations, in the rates charged by our pipeline systems, their ability to recover such costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

One of our pipeline systems, Northern Border, received a Notice of Violation (NOV) from the EPA alleging that Northern Border was in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on its system. As provided by the NOV, Northern Border has requested a conference with the EPA to discuss the violations alleged in the NOV. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty.

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, 2008, Great Lakes, Northern Border and Tuscarora had $430.0 million, $631.0 million and $61.8 million of debt outstanding, respectively. Of the debt outstanding, Great Lakes, Northern Border and Tuscarora have $19.0 million, $200.0 million and $4.4 million of debt maturing in 2009, respectively. Their respective levels of debt could have important consequences to Great Lakes, Northern Border and Tuscarora, including the following:

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- 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 unitholders.

The current capital and credit market conditions may adversely affect the Partnership s and/or our pipeline systems access to capital and cost of capital.

Access to capital markets is important to the Partnership to enable it to execute its business strategies, which include seeking opportunities to undertake accretive acquisitions and organic growth projects, and maximize the value of our existing portfolio of pipeline systems. Access to capital markets is also important to our pipeline systems ability to meet liquidity and capital resource requirements. Additionally, market conditions will impact the ability of our pipeline systems to access capital markets for debt under reasonable terms. Northern Border expects to refinance $200.0 million of Senior Notes in 2009 with a combination of equity contributions from its partners, fixed-rate and short-term variable-rate debt.

Recently, the general economic and capital market conditions in the United States and other parts of the world have deteriorated significantly and have adversely affected access to capital and increased the cost of capital. If recent conditions in the U.S. capital markets continue or become worse, the Partnership s and our pipeline systems future cost of debt and equity capital, and future access to capital markets could be adversely affected.

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 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.

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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 Partners. 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, governmental agencies and Indian reservations 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. Additionally, should we lose the services of TransCanada, we may not be able to replace those services for the same cost and our costs could increase. Further, we would not be able to evaluate potential growth opportunities and successfully complete acquisitions without TransCanada s resources.

Our pipeline systems may undertake or be dependent upon expansion and build projects which involve significant risks that could adversely affect our business.

Our pipeline systems have expansion and new build projects planned or underway, including Northern Border s $18.0 million Des Plaines Project. Additionally, expansion and new build projects, such as the Bison Project that would potentially deliver gas to Northern Border, are subject to a variety of factors outside their control. Factors such as weather, natural disasters, delays in obtaining key materials and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors may result in increased costs or delays in construction. Cost overruns or delays in completing a project could result in reduced transportation rates and liquidated damages to customers, as well as lost revenue opportunities. In addition, we cannot be certain

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that, if completed, these projects will perform in accordance with our expectations. Each of these risks could have a material adverse effect on our results of operations and cash flows.

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. The conditions of the U.S. and international credit markets may adversely affect our ability to obtain credit or draw on our current credit facility.

As of December 31, 2008, the Partnership had $536.8 million of debt outstanding, including the revolving credit and term loan agreement (Senior Credit Facility) and Senior Notes (2007 - $573.4 million). 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.

If the financial institutions that have extended credit commitments to us and our pipeline systems are adversely affected by the conditions of the U.S. and international capital markets, they may become unable to fund borrowings under their credit commitments, which could have a material and adverse impact on our financial condition and our ability to borrow additional funds, if needed.

In addition, our credit facilities contain restrictive covenants that may prevent us from engaging in certain transactions that are deemed 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 unitholders.

Any future debt may contain similar restrictions.

Increases in interest rates and general volatility in the financial markets and economy could adversely affect our business, our common unit price, results of operations, cash flows and financial condition.

As of December 31, 2008, TC PipeLines had $475.0 million outstanding under the Senior Credit Facility (2007 - $507.0 million), 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, 2008, 100 per cent of the variable interest rate exposure related to the Partnership s $475.0 million of debt outstanding under the Senior Credit Facility was mitigated by fixed interest rate swap arrangements. However, the interest rate option on $100.0 million of the Partnership s debt expires in May 2009.

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.

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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 662/3 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 the 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.

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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, but not the obligation, 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:

- 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 their 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

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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 interests in our pipeline systems may force TransCanada 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, 2008, we paid fees and reimbursements to our general partner in the amount of $2.1 million (2007 $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 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 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.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Tax Risks to Common Unitholders

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 tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal and state income taxes on our income at the applicable corporate tax rate. 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.

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Current laws 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 held in the operating Partnerships, which are generally treated as flow-through entities for income tax purposes, and as such the income from the pipeline systems generally have not been subject to income tax at the entity level. Several states have either adopted or are evaluating a variety of ways to subject partnerships to entity level taxation. For example, in 2008, Great Lakes recorded a Michigan business tax of $5.5 million relating to a new partnership level tax, of which the Partnership s share of the tax was $2.6 million. Imposition of such taxes on our pipeline systems will reduce the cash available for distribution to us and for other business needs by our pipeline systems, and adversely affect the amount of funds available for distribution to our unitholders.

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 tax 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 losses 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.

Tax-exempt and non-U.S. investors may have adverse tax consequences from owning common units.

An investment in common units by tax-exempt entities and foreign persons raises issues unique to these persons. For example, virtually all of our income allocated to organizations which is 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. Distributions to foreign persons will be reduced by withholding taxes, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We treat a purchaser of common units as having the same tax benefits without regard to the actual common units purchased. A successful IRS challenge could adversely affect the value of the common units.

To maintain uniformity of the economic and tax characteristics of our 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.

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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 and return filing requirements in states where they do not live as a result of an investment in our common 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. We may be required to withhold income taxes with respect to income allocable or distributions made to our unitholders. In addition, 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. We currently own assets and conduct business in California, Illinois, Indiana, Iowa, Michigan, Minnesota, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, Texas, and Wisconsin. Each of these states except for Nevada, South Dakota, and Texas, currently impose personal income taxes on individuals. Generally, these states also impose income taxes on corporations and other entities. 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.

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Item 3. Legal Proceedings

Our pipeline systems are parties to various legal actions or governmental proceedings that have arisen 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, 2008.

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.

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**	
2008			
First Quarter	**$ 37.30**	**$ 31.60**	**$ 0.700**
Second Quarter	**$ 36.96**	**$ 33.75**	**$ 0.705**
Third Quarter	**$ 34.98**	**$ 30.42**	**$ 0.705**
Fourth Quarter	**$ 31.72**	**$ 18.82**	**$ 0.705**
2007			
First Quarter	$ 37.54	$ 35.29	$ 0.650

Second Quarter	$	42.83	$	36.34	$	0.655
Third Quarter	$	40.69	$	32.98	$	0.660
Fourth Quarter	$	37.35	$	35.50	$	0.665

As of February 19, 2009, there were 100 registered holders of common units and approximately 16,200 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

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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 2008, the Partnership made cash distributions to unitholders and the general partner that amounted to $108.6 million compared to $86.7 million in 2007. These payments represented $0.665 per common unit for the quarter ended December 31, 2007, $0.700 per common unit for the quarter ended March 31, 2008 and $0.705 per common unit for the quarters ended June 30, 2008 and September 30, 2008. On February 13, 2009, the Partnership paid a cash distribution of $27.8 million to unitholders and the general partner, representing a cash distribution of $0.705 per common unit for the quarter ended December 31, 2008. The distribution was allocated in the following manner: $24.6 million to the holders of common units as of the close of business on January 30, 2009 (including $1.4 million to the general partner as holder of 2,035,106 common units and $6.1 million to TransCan Northern as holder of 8,678,045 common units), $2.6 million to the general partner as holder of incentive distribution rights, and $0.6 million to the general partner in respect of its two per cent general partner interest.

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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)	2008	2007(1)	2006(2)	2005	2004
Income Data (for the year ended December 31)					
Equity income from investment in Great Lakes	**57.3**	49.0			
Equity income from investment in Northern Border	**65.3**	61.2	56.6	45.7	50.0
Equity income from investment in Tuscarora			5.9	7.5	7.5
Transmission revenues	**31.6**	27.2	0.9		
Financial charges, net and other	**(30.1)**	(33.8)	(15.8)	(1.0)	(0.5)
Net income	**107.7**	89.0	44.7	50.2	55.1
Basic and diluted net income per unit	**$ 2.75**	$ 2.51	$ 2.39	$ 2.70	$ 2.99
Cash Flow Data (for the year ended December 31)					
Cash distribution paid per unit	**$ 2.775**	$ 2.565	$ 2.325	$ 2.300	$ 2.250
Balance Sheet Data (at December 31)					
Total assets	**1,448.5**	1,492.6	777.8	315.7	332.1
Long-term debt (including current maturities)	**536.8**	573.4	468.1	13.5	36.5
Partners equity	**875.6**	900.1	303.9	301.6	294.9

(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 Gas Transmission Limited Partnership (Great Lakes) and Northern Border Pipeline Company (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 United States of America (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

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

As of December 31, 2007, we acquired the remaining two per cent general partner interest in Tuscarora Gas Transmission Company (Tuscarora), thereby making it a wholly-owned subsidiary.

Our general partner interests in Great Lakes, Northern Border and Tuscarora represent our only material assets at December 31, 2008. As a result, we are dependent upon Great Lakes, Northern Border and Tuscarora for all of our available cash. Our pipeline systems derive their operating revenue from the provision of natural gas transportation services.

Great Lakes Overview

Great Lakes is a Delaware limited partnership formed in 1990. 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 transports natural gas from the Canadian 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 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 through Northeastern California and Northwestern Nevada to a terminus near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada.

OBSERVATIONS ON CURRENT ENVIRONMENT

With the economic conditions in the U.S. having changed dramatically in the last half of 2008, there has been a tightening of the credit markets, impacting the availability and cost of financing. Both industrial production and consumer spending fell sharply in the last half of 2008. Businesses have been increasingly faced with reduced demand for their products, increased credit tightening, and deteriorating counterparty creditworthiness. In addition, commodity prices have decreased dramatically from multi-year highs in the summer of 2008 to multi-year lows by the end of the year. In short, worldwide economies have entered a recessionary period.

While the current economic environment has reduced the demand for natural gas, once the economy returns to growth mode, North America s demand for natural gas is expected to rise, especially in light of reduced commodity prices combined with the relative environmental merits of natural gas versus other carbon based forms of energy. Natural gas supplies in North America are also expected to be impacted by the current environment, mainly due to lower prices, along with credit and liquidity impacts on natural gas producers. Production from specific natural gas basins in North America will be dependent upon relative operating costs, with reduced natural gas drilling activity expected to contribute to lower production overall.

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These reductions in natural gas demand and the changing geography and quantity of supply from various basins will impact the overall natural gas transportation infrastructure. With respect to our systems, demand for our pipeline systems transportation services are directly related to the demand and supply alternatives for natural gas in the markets served by our pipeline systems. In addition, the impact of any changes in demand on the revenues of our pipeline systems is dependent upon the levels of firm transportation contracts and the creditworthiness of the counterparties which hold those positions. Tuscarora has firm transportation contracts for 100 per cent of its available capacity as at January 31, 2009. Great Lakes average design capacity is 88 per cent contracted at January 31, 2009. Northern Border s system has the most exposure to changes in demand with approximately 60 per cent of its capacity available for 2009.

As we are dependent upon cash flows received from our pipeline systems to fund our distributions, if there is a prolonged impact to demand for natural gas transportation services or creditworthiness of our pipeline systems shippers, our partnership cash flows may be negatively impacted. However, we have a strong financial position, including an available unused credit facility at favorable rates, which gives us the capacity to meet any funding commitments to our investments, along with pursuing opportunities to grow.

OUTLOOK

The Partnership

Access to capital markets is important to the Partnership to enable it to execute its business strategies, which include seeking opportunities to undertake accretive acquisitions and organic growth projects, and maximize the value of our existing portfolio of pipeline systems. Recently, the general economic and capital market conditions in the U.S. and other parts of the world have deteriorated significantly and have adversely affected access to capital and increased the cost of capital. If these conditions continue or become worse, the Partnership s future cost of debt and equity capital, and future access to capital markets could be adversely affected.

Our strong financial position, including an available unused credit facility, gives us the capacity to pursue opportunities to grow in a sustained and disciplined manner for the long-term benefit of our unitholders.

Great Lakes

At January 31, 2009, the weighted average remaining contract life of Great Lakes contracts was 2.7 years and 88 per cent of its average design capacity was contracted on a firm basis for the first quarter of 2009. As of January 31, 2009, Great Lakes had approximately 12 per cent of its average design capacity uncontracted beginning in the second quarter of 2009 and 14 per cent by December 31, 2009. Dependent on competitive factors and prevailing market conditions, Great Lakes may discount transportation capacity as needed to optimize revenue.

Northern Border

At January 31, 2009, the weighted average remaining contract life of Northern Border s contracts was 2.1 years and 82 per cent of its capacity was contracted on a firm basis for the first quarter of 2009. As of January 31, 2009, Northern Border had approximately 60 per cent of its design capacity uncontracted beginning in the second quarter of 2009 through the remainder of 2009. Prevailing market conditions and increasing competitive factors in North America expected in 2009, including REX, will continue to challenge Northern Border s ability to market its available capacity, and may negatively impact revenue in 2009.

Tuscarora

At January 31, 2009, the weighted average remaining contract life of Tuscarora s contracts was 11.6 years. As of January 31, 2009, Tuscarora has approximately two per cent of its design capacity uncontracted beginning in the second quarter of 2009.

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FACTORS THAT IMPACT OUR BUSINESS

Key factors that impact our business are the cash flows received from our investments and our ability to maintain a strong financial position. Cash flows from our investments are dependent upon the ability of Great Lakes and Northern Border to make distributions to us and of Tuscarora to generate positive operating cash flows. Partnership cash flows from our investments are necessary to fund distributions to our unitholders. A strong 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

Our pipeline systems provide natural gas transportation services to their customers. Key factors that impact their business 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 they access, primarily the Western Canada Sedimentary Basin (WCSB). Our pipeline systems provide their customers with natural gas transportation services to market demand areas. The net WCSB flows to U.S. markets are dependent upon natural gas production levels, demand for natural gas in Canada, and storage capacity for Canadian natural gas and demand for storage injection in Canada. The net WCSB flows to U.S. markets were lower in 2008 compared to 2007, due mainly to a decrease in production. Colder than normal weather conditions also contributed to increased Canadian demand. At the same time, there has been an increase in U.S. natural gas production, mainly due to the development of unconventional reserves in the lower-48 States.

Decreases in WCSB production are expected to continue in 2009 as there has been a decline in drilling and exploration activity by WCSB producers, mainly related to the sharp reductions in commodity prices over the last half of 2008. Decreases in WCSB production are also related to higher supply costs, including higher royalties, and competition for capital from other North American basins that have lower exploration costs. Commodity prices, combined with restrictions on liquidity and access to capital, have contributed to the postponement and/or cancellation of certain oil sands projects, which may impact Canadian demand for WCSB natural gas.

Factors which may mitigate declines related to WCSB production in the future include strengthening gas prices and decreases in oil prices as they affect demand from Alberta oil sands production. We expect WCSB producers will continue to explore and develop new fields in Western Canada as well as direct significant activity at unconventional resources such as coalbed methane and shale gas. As well, additional Canadian natural gas supply sources may be available in the future if new pipeline projects associated with the Montney and Horn River shale gas regions in Western Canada, the Mackenzie Delta in Northern Canada and the North Slope of Alaska are constructed.

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. Although demand for natural gas is expected to decline in North America in 2009 with the current economic downturn, we expect a demand increase in the long-term. Demand for natural gas transportation service on our pipeline systems is directly correlated to the activity in the natural gas markets served by these systems. 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.

The decline in net WCSB flows to markets in 2008 was not the primary factor which negatively impacted throughput on our pipeline systems in 2008. We cannot predict the impact of any continued declines in net WCSB flows to markets on 2009 throughput as this will depend on those net flows in the future and market conditions in the markets our pipeline systems serve.

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The impact of changes in demand for natural gas transportation services on operating revenues for our pipeline systems is dependent upon the extent to which capacity has been contracted under long-term firm contracts.

Throughput on Great Lakes pipeline system in 2008 was slightly lower than 2007 and 2006 primarily due to underutilization of firm contracts, and therefore had minimal impact on revenue.

The majority of Northern Border s supply comes from the WCSB. Increased drilling and production activity, primarily in Wyoming within the Powder River Basin, has resulted in producers expressing interest in the proposed Bison Pipeline Project which, if completed, would bring approximately 407 MMcf/d of additional supply from this region to Northern Border and would increase Northern Border s supply diversity. See the Year in Review 2008 section of Item 1. Business for additional information about the Bison Pipeline Project. Growth in other producing regions such as the Williston Basin of Montana and Northern Dakota, and further development of the Rockies supply basin, may provide future opportunities for supplies being delivered from these other producing regions which would further diversify Northern Border s supply sources. Finally, another source of supply could come from future development of coal gasification projects that would be built close to coal producing regions most likely in North Dakota.

The Midwest markets served by Northern Border were impacted in 2008 by incremental supply from the Rockies natural gas basin with the completion of the Western segment of the Rockies Express Pipeline. Demand for transportation on Northern Borders pipeline system in 2008 declined as a result of this increased supply competition, as discussed further under Competition .

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 s largest customers are in the Reno-Sparks area of Washoe County, Storey County and downstream of the Paiute system, where gas consumption has increased significantly as a result of increased industrial use, population growth and gas-fired power generation.

Customers and Contracting

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 marketers.

Our pipeline systems are subject to credit risk related to the ability of their customers or shippers to meet their contractual payment obligations. The tariffs on our pipeline systems allow for them to require customers to post credit support under the terms of these tariffs. This somewhat mitigates our pipeline systems exposure to counterparty credit risk. During 2008, the bankruptcy of Lehman Brothers Holdings Inc. and the weakening of companies within the energy industry have underscored the importance of these tariff provisions. However, in some instances it is also limiting the amount of capacity a customer can contract for, as their ability to meet or post the required support is being negatively impacted by their liquidity constraints.

Great Lakes average contracted capacity was near 100 per cent of its average design capacity for 2008. At January 31, 2009, 88 per cent of its average design capacity was contracted on a firm basis. In November 2008, TransCanada renewed 360 million Dth/d, or 16 per cent, of capacity on Great Lakes through October 2012. As well, Great Lakes transportation values increased throughout 2008, partially due to the increase in tolls from its main competitor (the TransCanada Mainline), and partially because of strong spread values between Alberta and Dawn, Ontario. As a result, Great Lakes sold new contracts as well as renewed long and short haul contracts at maximum tariff rates for the next two years. Depleted storage inventories in Eastern Canada and the U.S. supported demand for Great Lakes transportation, as customers utilized Great Lakes transportation to access and fill storage locations adjacent to its pipeline over the summer months.

Northern Border s average contracted capacity was 90 per cent of its design capacity for 2008. Transportation values on Northern Border s system were strong in the fourth quarter, mainly related to weather conditions, which enabled Northern Border to sell its available capacity in the fourth quarter of 2008 at maximum rates. Northern Border s capacity to Chicago remains attractive and is substantially under contract for multiple years. Legacy contacts related to this capacity that were set to expire in the near term have been renewed. However, prevailing market conditions and increasing competitive factors in North America, including in-service of the Western segment of the Rockies

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Express Pipeline (REX West), have caused Northern Border to experience a reduction in its revenues due to lower capacity sales and greater discounting of its rates. These factors, as well as expirations of certain long-term contracts, will continue to impact Northern Border s ability to market its available capacity into 2009. As of January 31, 2009, Northern Border had approximately 60 per cent of its design capacity uncontracted beginning in the second quarter of 2009 through the remainder of 2009.

Tuscarora operates under long-term contacts with 100 per cent of its design capacity contracted with a weighted average remaining life on those contracts of 11.6 years as of January 31, 2009. The weighted average remaining life of Tuscarora s contracts increased during 2008 with the completion of the compressor station expansion project, which was underpinned by a 22.5-year contract.

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.

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 (REX East), discussed below, may provide opportunities for Great Lakes to market its Eastern zone capacity for storage injection and withdrawal, which has historically been underutilized.

The pipeline systems that offer primary competition to Northern Border include Alliance Pipeline, Great Lakes, Gas Transmission Northwest, and other pipelines that interconnect with the TransCanada mainline for WCSB supply. Additionally, Northern Border competes with other pipelines that serve Northern Border s market areas, including Northern Natural Gas Company, Alliance Pipeline, ANR Pipeline Company, Midwestern Gas Transmission Company and Natural Gas Pipeline of America. 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. REX West increased supply competition in Midwest markets and negatively impacted Northern Border s flows and sales of available capacity in 2008 and is anticipated to continue to impact in 2009. REX East, from Missouri to Ohio, will transport natural gas further east, potentially mitigating excess supply in Northern Border s Ventura market. REX has announced that REX East will be placed in service in the second and fourth quarters of 2009. As well, two other new pipeline projects are projected to go into service in 2009 that will ship growing supply volumes from the lower Mid-Continent east to the existing gulf coast infrastructure that includes transportation access to the Chicago market. As with all new pipeline projects, these will impact overall North American natural gas flows.

As of January 31, 2009, Northern Border had approximately 60 per cent of its design capacity uncontracted beginning in the second quarter of 2009 through the remainder of 2009. Additional supply in the Chicago market may impact Northern Border s ability to contract upstream available capacity in 2009 if flows to Chicago materially decrease.

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 also has access to supply regions as its upstream pipelines have excess capacity.

Government Regulation

Natural gas transportation is regulated by the Federal Energy Regulatory Commission (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 regulated 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

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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. This measure does not have any standardized meaning prescribed by U.S. generally accepted accounting principles (GAAP). It is, therefore, considered to be a non-GAAP measure and is unlikely to be comparable to similar measures presented by other entities. Partnership cash flows is the sum of net income, cash distributions received from Great Lakes, Northern Border and Tuscarora (in 2006), and cash flows provided by Tuscarora s operating activities (in 2007 and 2008) less equity income from investments in Great Lakes, Northern Border and Tuscarora (in 2006) and Tuscarora s net income (in 2007 and 2008).

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 2008; 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 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. The following summarizes the Partnership s and our pipeline systems accounting policies and estimates, and 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.

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* (SFAS No. 71). 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, 2008, Northern Border reflected regulatory assets of $21.7 million on its balance sheet (2007 - $20.7 million). 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.

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As at December 31, 2008 and 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 value is a market-based measure of the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

We assess our goodwill for impairment at least annually, based on SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). 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, 2008 and 2007, we had $81.7 million of goodwill recorded on our balance sheet related to the Tuscarora acquisitions. No impairment of goodwill existed at December 31, 2008.

Impact of New Accounting Standards

The Partnership adopted the provisions of SFAS No. 157, *Fair Value Measurements* (SFAS No. 157) for its financial assets and liabilities measured at fair value on a recurring basis effective January 1, 2008. *Under SFAS No. 157, the financial assets and liabilities that are recorded at fair value on a recurring basis are categorized into one of three categories based upon a fair value hierarchy. We have classified all of our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. Refer to Note 17 of the Partnership s financial statements for the impact to our financial statements.*

The Financial Accounting Standards Board (FASB) issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157* (Staff Position No. 157-2), in February 2008, which delayed the effective date of SFAS No. 157 for all non-financial assets and liabilities that are measured at fair value on a non-recurring basis until fiscal years beginning after November 15, 2008. These non-financial items include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and asset retirement obligations initially measured at fair value. The effect of adopting Staff Position No. 157-2 is not expected to be material to our results of operations or financial position.

The FASB issued Staff Position No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,* in October 2008, which clarifies the application of SFAS No. 157 in a market that is not active. This Staff Position is effective upon issuance and the Partnership s financial statements were not impacted by this standard.

The FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS No. 159), in February 2007, which permits entities to choose to measure selected financial assets and financial liabilities at fair value for fiscal years beginning on or after November 15, 2007. The fair value option established by SFAS No. 159 permits all entities to choose to measure

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eligible items at fair value at specified election dates. The Partnership has not elected the fair value option for any non-derivative financial assets or liabilities.

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) in June 2007. EITF 07-4 addresses how current period earnings of a Master Limited Partnership 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 conclusion was ratified by the FASB in March 2008 and is effective for fiscal years beginning after December 15, 2008. We are currently reviewing the applicability of EITF 07-4 to our results of operations and financial position.

The FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162), in May 2008, which codifies the sources of accounting principles and the related framework to be utilized in preparing financial statements in conformity with GAAP. The requirements of this standard are not expected to have a material impact on our results of operations or financial position.

The FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS No. 161) in March 2008. SFAS No. 161 expands the disclosure requirements for derivative instruments and hedging activities with respect to how and why entities use derivative instruments, how they are accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and the related impact on financial position, financial performance and cash flows. The requirements of this standard will not have a material effect on the Partnership s disclosure as a result of adoption on January 1, 2009.

The FASB issued SFAS No. 141(R), *Business Combinations* (SFAS No. 141(R)) in December 2007, which replaces SFAS No. 141, *Business Combinations* (SFAS No. 141). 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 impact the accounting for business combinations subsequent to January 1, 2009.

YEAR IN REVIEW

TC PipeLines

Liquidity and Capital Resources

In 2008, $13.0 million of the senior term loan was repaid, leaving $475.0 million outstanding under the senior term loan at December 31, 2008. $19.0 million of the senior revolving facility was repaid in 2008, leaving no amount outstanding under the senior revolving credit facility at December 31, 2008. The Partnership has $250.0 million of capacity available under its senior revolving credit facility.

Great Lakes

Operating Revenues

Operating revenues increased in 2008 compared to 2007 primarily due to the timing of the Great Lakes acquisition, which resulted in a full first quarter of income contribution in 2008 as compared to 37 days in the first quarter of 2007. Additionally, increased sales of short-term firm transportation services at higher average transportation rates, as well as increased transport of interruptible services and storage-related services contributed to higher operating revenues, partially offset by decreased long-term services due to capacity turn back and underutilization of contracts. For the year ended December 31, 2008, Great Lakes average contracted capacity was near 100 per cent of its average design capacity. As of January 31, 2009, the weighted average remaining life of Great Lakes contracts was 2.7 years.

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	2008	For the period February 23 to December 31, 2007
MMcf delivered	**784,284**	693,017
MMcf/d average throughput	**2,143**	2,221
Average contracted capacity(1)	**100%**	100%

(1) Great Lakes average contracted capacity for the comparative period is calculated for the period March 1 to December 31, 2007.

Michigan Business Tax

Beginning in 2008, the state of Michigan enacted the Michigan Business Tax (MBT) which is an income tax levied at the partnership level. Great Lakes files the MBT return on a unitary basis with certain TransCanada affiliates. A tax payment agreement between Great Lakes and these affiliates provides that Great Lakes MBT liability is determined as if a separate return was filed. In 2008, the MBT income tax expense was $5.5 million.

Northern Border

Operating Revenues

Operating revenues in 2008 were lower compared to 2007 primarily due to decreased contracted capacity as a result of the increase of supply competition in Northern Border s market area, largely from REX West going in-service in 2008. Correspondingly, Northern Border s average throughput decreased from 2007 to 2008 as shown in the table below. The weighted average life of Northern Border s contracts increased to 2.1 years at January 31, 2009 from 1.3 years at January 31, 2008. In August 2008, Northern Border conducted a binding open season seeking interest in an expansion project from Harper, Iowa to Manhattan, Illinois and received binding shipper commitments. As a result of an open season, Northern Border renewed approximately 350 MMcf/d at maximum and discount rates, for terms ranging from 5 to 12 years for various transportation paths to Chicago, which eliminated the interest in the proposed expansion project.

Year Ended December 31	2008	2007
MMcf delivered	**731,138**	799,637
MMcf/d average throughput	**2,041**	2,247
Average contracted capacity	**90%**	97%

Sale of Bison Pipeline LLC

A gain of $16.2 million was recognized on the sale of Northern Border s wholly-owned subsidiary, Bison Pipeline LLC, which resulted in higher net income in 2008 compared to 2007. Distributions paid in the third quarter of 2008 included a special distribution of $16.4 million due to the sale.

Tuscarora

Operating Revenues

Operating revenues for the year ended December 31, 2008 were higher compared to 2007 primarily due to a new firm transportation service contract that supported the Likely compressor station expansion project that went into service on April 1, 2008 (2008 Expansion Project). Tuscarora s average throughput and contracted capacity increased in 2008 compared to 2007 as shown in the table below. The weighted average remaining life of Tuscarora s contracts increased to 11.6 years at January 31, 2009 from 10.4 years at January 31, 2008 due to the contract mentioned above.

Year Ended December 31	**2008**	**2007**
MMcf delivered	**30,061**	28,257
MMcf/d average throughput	**82**	77
Average contracted capacity	**98%**	96%

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2008 Expansion Project

Tuscarora s 2008 Expansion Project to support Sierra Pacific Power Company s Tracy Combined Cycle Power Plant went into service on April 1, 2008, with a final cost of approximately $20.4 million which was within the original cost estimate. The costs will be recovered from rates charged to Sierra Pacific Power under a transportation service agreement for 40,000 Dth/d for a term of 22.5 years. The contract is expected to generate approximately $5.8 million of annual revenue.

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 our financial performance. We believe this summary provides a more meaningful comparison of our 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.

Year Ended December 31, 2008 (millions of dollars)	**Partnership**	**Tuscarora(1)**	**Corporate**	**Great Lakes(2)**	**Northern Border(3)**
Transmission revenues	**31.6**	31.6		287.1	293.1
Operating expenses	**(9.5)**	(5.4)	(4.1)	(67.1)	(78.0)
	22.1	26.2	(4.1)	220.0	215.1
Depreciation	**(6.9)**	(6.9)		(58.5)	(61.1)
Financial charges, net and other	**(30.1)**	(4.3)	(25.8)	(32.6)	(21.8)
Michigan business tax				(5.5)	
				123.4	132.2
Equity income	**122.6**			57.3	65.3
Net income	**107.7**	15.0	(29.9)	57.3	65.3

Year Ended December 31, 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; therefore, the amounts for 2007 only include results for the period of February 23 to December 31, 2007.

(3) TC PipeLines owns a 50 per cent general partner interest in Northern Border. Equity income from Northern Border includes amortization of a $10.0 million transaction fee paid to the operator of Northern Border at the time of the additional 20 per cent acquisition in April 2006.

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Year Ended December 31, 2006 (millions of dollars)	Partnership	Tuscarora(4) Dec 20-31	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 $10.0 million transaction fee paid to the operator of Northern Border at the time of the acquisition.

Year Ended December 31, 2008 Compared with the Year Ended December 31, 2007

Net income increased $18.7 million to $107.7 million in 2008 compared to $89.0 million in 2007. This increase is primarily due to increased financial results from each of our pipeline systems, combined with a reduction in financial charges, net and other at the Partnership level.

Equity income from investment in Great Lakes was $57.3 million in 2008, an increase of $8.3 million compared to $49.0 million for the period February 23 to December 31, 2007. The increase in equity income is primarily due to the timing of the Great Lakes acquisition, which resulted in a full first quarter of income contribution in 2008 as compared to 37 days in the first quarter of 2007. In addition, Great Lakes experienced an overall increase in transmission revenues in 2008 as compared to 2007, offset by increased operating expenses and the implementation of Michigan Business Tax. Transmission revenues increased primarily due to increased sales of short-term firm transportation services at higher average transportation rates, as well as increased transport of interruptible services and storage related services, offset by decreased long-term services. Operating expenses increased primarily due to integration costs related to its acquisition, employee benefit costs, and pipeline inspection costs, partially offset by decreased property and other non-income taxes and lower main engine repair costs. In 2008, Great Lakes recorded Michigan Business Tax of $5.5 million.

Equity income from investment in Northern Border increased $4.1 million to $65.3 million in 2008 compared to 2007. The increase in equity income is primarily due to a $16.2 million (Partnership share - $8.1 million) gain on the sale of Bison Pipeline LLC. Excluding this gain, Northern Border s net income decreased $4.0 million compared to the prior year due to a $16.3 million decrease in transmission revenues, partially offset by decreased financial charges and operating expenses. Northern Border s transmission revenues decreased in 2008 compared to the prior year primarily due to a decrease in contracted capacity as natural gas supply from the Rockies Basin into the Mid-Continent market from the in-service of the Western segment of the Rockies Express Pipeline impacted demand. Interest expense decreased in 2008 compared to the prior year due to lower interest rates. Operating expenses decreased in 2008 compared to 2007 primarily due to decreased taxes other than income and a $2.3 million transition related charge in 2007 related to the reimbursement for shared equipment and furnishings, partially offset by increased electric compressor charges..

Tuscarora s net income was $15.0 million in 2008, an increase of $3.4 million compared to 2007. The increase in net income is primarily due to increased transmission revenues resulting from the 2008 Expansion Project.

Costs at the Partnership level decreased $2.9 million to $29.9 million in 2008 compared to 2007. This decrease relates primarily to lower financial charges as a results of lower interest rates and average debt outstanding, partially offset by losses on interest rate derivatives.

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

Net income increased $44.3 million 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, of which we acquired a 46.45 per cent interest on February 22, 2007. At Great Lakes level, net income for the period from acquisition to December 31, 2007 was $105.5 million, in line with our expectations. In 2007, approximately 91 per cent of Great Lakes transportation revenues were derived from long-term firm service contracts.

Equity income from investment in Northern Border increased $4.6 million to $61.2 million in 2007 compared to 2006 due to the additional 20 per cent general partner interest in Northern Border acquired on April 6, 2006, offset by a reduction in Northern Border s net income. At Northern Border s level, slight increases in operating and depreciation expenses, along with a small reduction in transmission revenues contributed to the decrease in net income. Operating expenses increased compared to 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. Depreciation expense increased compared to the prior year primarily due to the change in depreciation rates effective January 1, 2007 as a result of the 2005 rate case settlement. 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.

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.

Tuscarora s net income decreased $1.7 million 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.

Partnership Cash Flows

The Partnership uses the non-GAAP financial measures Partnership cash flows and Partnership cash flows allocated to common units as financial performance measures. As the Partnership s financial performance underpins the availability of cash flows to fund the cash distributions that the Partnership pays to its unitholders, the Partnership believes these are key measures of the available cash flows to its unitholders. The following Partnership cash flows information is presented to enhance investors understanding of the way that management analyzes the Partnership s financial performance. Partnership cash flows and Partnership cash flows allocated to common units are provided as a supplement to financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP.

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Year Ended December 31 (millions of dollars except per common unit amounts)	2008	2007	2006
Net Income	**107.7**	89.0	44.7
Add:			
Cash distributions from Great Lakes	**73.9**	61.3	
Cash distributions from Northern Border	**90.7**	86.3	80.4
Cash flows provided by Tuscarora s operating activities(1)	**21.5**	17.6	
Cash distributions from Tuscarora(1)			7.7
	186.1	165.2	88.1
Less:			
Equity income from investment in Great Lakes	**(57.3)**	(49.0)	
Equity income from investment in Northern Border	**(65.3)**	(61.2)	(56.6)
Tuscarora s net income(1)	**(15.0)**	(11.6)	
Equity income from investment in Tuscarora(1)			(5.9)
	(137.6)	(121.8)	(62.5)
Partnership cash flows	**156.2**	132.4	70.3
Partnership cash flows allocated to general partner (2)	**(11.8)**	(7.7)	(2.9)
Partnership cash flows allocated to common units	**144.4**	124.7	67.4
Cash distributions declared	**(110.8)**	(101.0)	(44.1)
Cash distributions declared per common unit (3)	**$ 2.815**	$ 2.630	$ 2.350
Cash distributions paid	**(108.6)**	(86.7)	(43.5)
Cash distributions paid per common unit (3)	**$ 2.775**	$ 2.565	$ 2.325
Weighted average common units outstanding *(millions)*	**34.9**	32.3	17.5

(1) Refer to Note 5 of the Partnership s financial statements for cash flows from Tuscarora s operating activities for the year ended December 31, 2006. 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.

(2) Partnership cash flows allocated to general partner represents the cash distributions paid to the general partner with respect to its two per cent interest plus an amount equal to incentive distributions.

(3) Cash distributions declared per common unit and cash distributions paid per common unit are computed by dividing cash distributions, after the deduction of the general partner s allocation, by the number of common units outstanding. The general partner s allocation is computed based upon the general partner s two per cent interest plus an amount equal to incentive distributions.

Year Ended December 31, 2008 Compared with the Year Ended December 31, 2007

Partnership cash flows increased $23.8 million to $156.2 million in 2008 compared to $132.4 million in 2007. This increase was a result of increased cash distributions from Great Lakes and Northern Border, increased cash flows provided by Tuscarora s operating activities and decreased costs at the Partnership level.

Cash distributions from Great Lakes were $73.9 million in 2008, an increase of $12.6 million compared to the prior year. The increase in cash distributions from Great Lakes is due primarily to a full year of ownership in 2008. Cash distributions from Northern Border increased $4.4 million to $90.7 million in 2008 compared to 2007 due primarily to the special distribution of $8.2 million received in relation to the gain on the sale of Bison Pipeline LLC. Cash flows provided by Tuscarora s operating activities were $21.5 million in 2008, an increase of $3.9 million compared to the prior year primarily due to additional transmission revenues resulting from the 2008 Expansion Project. Costs at the Partnership level decreased by $2.9 million to $29.9 million in 2008 compared to 2007 primarily due to lower

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financial charges as a result of lower interest rates and average debt outstanding, partially offset by losses on interest rate derivatives.

In 2008, Tuscarora made capital expenditures of $6.8 million that related primarily to the 2008 Expansion Project, compared to $13.2 million in 2007. In February 2007, the Partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation for $733.0 million in cash. In April 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 Partnership paid distributions of $108.6 million in 2008, an increase of $21.9 million compared to 2007 due to an increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts. In 2007, the proceeds from net equity issuances of $607.0 million, including the general partner s contribution to maintain its two per cent interest, were used to acquire Great Lakes. The Partnership funded the balance of the acquisition cost with a draw on its revolving credit and term loan agreement (Senior Credit Facility). We repaid a net $36.6 million of the outstanding balance on our debt in 2008.

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

Partnership cash flows increased $62.1 million to $132.4 million in 2007 compared to $70.3 million in 2006. This increase was primarily a result of cash flows received from acquisitions made in 2007 and 2006, partially offset by increased costs at the Partnership level.

Partnership cash flows in 2007 included cash distributions received of $61.3 million resulting from the acquisition of Great Lakes. Cash distributions 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 $17.6 million, while the distributions received from Tuscarora in 2006 were $7.7 million. Costs at the Partnership level increased $14.6 million to $32.8 million in 2007 compared to 2006 primarily due to increased financial charges related to higher outstanding debt balances.

In 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation for $733.0 million in cash. 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. 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.

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 2008 Expansion Project.

The Partnership paid distributions of $86.7 million in 2007, an increase of $43.2 million compared to 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.

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

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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, 2008 included the following:

		Payments Due by Period			
(millions of dollars)	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
Senior Credit Facility due 2011	475.0		475.0		
7.13% Series A Senior Notes due 2010	51.3	3.1	48.2		
7.99% Series B Senior Notes due 2010	5.0	0.5	4.5		
6.89% Series C Senior Notes due 2012	5.5	0.8	1.6	3.1	
Interest payments on Senior Credit Facility (a)	62.7	21.7	41.0		
Interest payments on Senior Notes	8.6	4.3	4.2	0.1	
Fair value of derivative contracts (b)	31.7	11.8	19.9		
Operating leases	0.3	0.1	0.1	0.1	
	640.1	42.3	594.5	3.3	

(a) Interest payments on Senior Credit Facility include the hedging effect of the derivative financial instruments placed on all of the outstanding debt. Refer to the Interest Rate Swaps and Options section below for details of the hedges. The weighted average interest rate incurred for the quarter ended December 31, 2008 of 3.18% was used to calculate interest payments for all unhedged debt. The interest payment calculation assumes no principal repayments until maturity.

(b) The anticipated timing of settlement of the fair value of derivative contracts assumes no changes in interest rates from December 31, 2008.

The Partnership s Debt and Credit Facilities

The Partnership has a revolving credit and term loan agreement (Senior Credit Facility) with a banking syndicate. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. In 2008, $13.0 million of the senior term loan was repaid (2007 - $18.0 million), leaving $475.0 million outstanding under the senior term loan at December 31, 2008. No amount is outstanding under the revolving portion of the Senior Credit Facility at December 31, 2008 (2007 - $19.0 million), leaving $250.0 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 London Interbank Offered Rate (LIBOR) or the prime rate plus, in either case, an applicable margin. There was $475.0 million outstanding under the Senior Credit Facility at December 31, 2008 (2007 - $507.0 million). The underlying interest rate on the Senior Credit Facility averaged 3.75 per cent for the year ended December 31, 2008 (2007 6.01 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.15 per cent for the year ended December 31, 2008 (2007 5.55 per cent). Prior to hedging activities, the interest rate was 2.67 per cent at December 31, 2008 (2007 5.62 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, 2008, the Partnership was in compliance with all of its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

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Series A, B and C Senior Notes are secured by Tuscarora s transportation contracts, supporting agreements and substantially all of Tuscarora s property. The note purchase agreements contain certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners.

The Partnership views its core banking group as solid, particularly in light of the current market environment, and has established a strong relationship with these institutions. As of February 27, 2009, the Partnership had no outstanding borrowings under the $250.0 million revolving portion of the Senior Credit Facility which expires on December 12, 2011. Additionally, the Partnership renewed an existing $250.0 million debt and equity shelf prospectus in December 2008.

Interest Rate Swaps and Options

The Partnership uses derivatives to assist in managing its exposure to interest rate risk. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $475.0 million at December 31, 2008 (2007 - $400.0 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 at 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 is 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

Effective January 1, 2008, we adopted the provisions of SFAS No. 157. Under SFAS No. 157, financial assets and liabilities that are recorded at fair value on a recurring basis are categorized into one of three categories based upon a fair value hierarchy. We have classified all our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At December 31, 2008, the fair value of the interest rate swaps and options accounted for as hedges was negative $31.7 million (2007 - negative $9.8 million), of which $11.8 million is classified as a current liability (2007 - $2.5 million). The fair value of the interest rate swaps and options is calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change.

For the year ended December 31, 2008, we recorded interest expense of $6.9 million in regards to the interest rate swaps and options (2007 interest income of $1.4 million).

Capital Requirements

Northern Border s distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by the Management Committee to establish the timing and amount of required equity contributions. In accordance with this policy and, to a lesser extent, in anticipation of the equity financing of Northern Border s Des Plaines Project, Northern Border currently estimates an equity contribution of approximately $85 million in 2009, of which the Partnership s share would be approximately $43 million. The Partnership expects to finance this equity contribution with a combination of debt and operating cash flows.

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 to repay indebtedness.

In 2008, Tuscarora incurred $6.8 million of capital expenditures (2007 - $13.2 million), of which $6.7 million related to its 2008 Expansion Project (2007 - $12.2 million). These capital expenditures were funded with operating cash flows.

To the extent the Partnership has any additional capital requirements with respect to our pipeline systems or makes acquisitions in 2009, 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, represents the incentive distribution rights.

2008 Fourth Quarter Cash Distribution

On January 20, 2009, the Board of Directors of the general partner declared the Partnership s 2008 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 13, 2009 to unitholders of record as of January 30, 2009, totaled $27.8 million and was paid in the following manner: $24.6 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $6.1 million to TransCan Northern Ltd. (TransCan Northern) as holder of 8,678,045 common units), $2.6 million to the general partner as holder of the incentive distribution rights, and $0.6 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 sources of liquidity are cash generated from operating activities, bank credit facilities and equity contributions from their partners. 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 unsecured notes or equity contributions from our pipeline systems partners. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends on their financial position and if market conditions permit.

Our pipeline systems believe that their ability to obtain financing at reasonable rates, together with their history of consistent cash flow from operating activities, provide a solid foundation to meet their future liquidity and capital resource requirements. The Partnership s pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs, which allow them to request credit support as circumstances dictate.

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Summary of Great Lakes Contractual Obligations

Great Lakes contractual obligations related to debt as of December 31, 2008 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
8.74% series Senior Notes due 2009 to 2011	30.0	10.0	20.0		
6.73% series Senior Notes due 2009 to 2018	90.0	9.0	18.0	18.0	45.0
9.09% series Senior Notes due 2012 to 2021	100.0			20.0	80.0
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	355.8	32.9	61.3	55.3	206.3
	785.8	51.9	99.3	93.3	541.3

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 restrictive covenants in the Senior Note Agreements, approximately $232.0 million of Great Lakes partners capital was restricted as to distributions as of December 31, 2008 (2007 - $237.0 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2008.

The aggregate estimated fair value of Great Lakes long-term debt was $413.1 million for 2008. The aggregate annual required repayment of senior notes is $19.0 million for each year 2009 through 2013. In 2008, interest expense related to Great Lakes senior notes was $34.2 million (2007 - $35.1 million) (2006 - $36.0 million).

Other

Great Lakes entered into a cash management agreement with TransCanada whereby Great Lakes funds are pooled with other TransCanada affiliates. The agreement also gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for Great Lakes operating needs.

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, 2008, included the following:

		Payments Due by Period			
(millions of dollars)	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**More Than 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	181.0			181.0	
Interest payments on debt	270.4	36.4	49.9	39.6	144.5
Operating leases	69.6	2.5	4.1	3.8	59.2
Other long-term obligations	4.5	3.0	1.5		
	975.5	241.9	55.5	224.4	453.7

Interest Payments on Debt

Interest payments on Northern Border s credit agreement include the hedging effect of the Collar Agreement. Refer to the Interest Rate Collar Agreement section below for further details. The interest rate at December 31, 2008 of 3.36 per cent was used to calculate the interest payments for all unhedged debt. The interest payment calculation

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assumes no principal repayments until maturity.

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, LLC (ONEOK Partners GP) and TransCanada Northern Border (TCNB), 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.

In connection with the construction of the Des Plaines Project, Northern Border has commitments of $2.2 million as of December 31, 2008.

Amended and Restated Credit Agreement

On April 27, 2007, Northern Border entered into a $250.0 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 Northern Border s $175.0 million revolving credit agreement dated as of May 16, 2005 and was used to repay all of the $150.0 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 $100.0 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 an applicable margin 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. 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 maintain a leverage ratio (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 specified material acquisitions are consummated, the permitted leverage ratio is increased to 5.50 to 1 for the first three full calendar quarters following the acquisition. At December 31, 2008, 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, 2008, Northern Border s outstanding borrowings under its credit agreement were $181.0 million (2007 - $166.0 million). The average interest rate on Northern Border s credit agreement at December 31, 2008 was 3.36 per cent (2007 5.35 per cent).

Interest Rate Collar Agreement

In August 2007, Northern Border entered into a zero cost interest rate collar agreement (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. Northern Border has designated the Collar Agreement as a cash flow hedge. At December 31, 2008, Northern Border s balance sheet reflected an unrealized loss of approximately $3.6 million (2007 - $1.9 million) with a corresponding decrease to accumulated other comprehensive loss related to the changes in fair value of the Collar Agreement since inception. In 2008, Northern Border recorded interest expense of $1.7 million under the Collar Agreement (2007 - nil). Since inception, hedge ineffectiveness has had no impact on income.

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,

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maturity dates and prepayment premiums.

Northern Border s senior notes issuances of $200.0 million due in 2009 and $250.0 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 on September 1, 2009 with a combination of equity contributions from its partners, fixed-rate and short-term variable-rate debt. The existing conditions in the capital and credit markets could result in less favorable terms and higher rates than are currently in place. 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 $150.0 million of its 6.25 per cent senior notes due May 1, 2007 with borrowings under the 2007 Credit Agreement. At December 31, 2008, the aggregate fair value of the outstanding senior notes was approximately $447.0 million (2007 - $493.0 million). In 2008, interest expense related to the senior notes was $34.3 million (2007 - $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 amounts and timing of cash distributions, where the amounts of such distributions are 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.

Great Lakes distribution policy is to distribute 100 per cent of distributable cash flow based generally on earnings before current income taxes and depreciation less debt repayments and capital expenditures. This defined formula is subject to Management Committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

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 January 30, 2009, a cash distribution of $27.0 million was declared and paid by Great Lakes for the fourth quarter of 2008, of which TC PipeLines 46.45 per cent share was $12.5 million. On February 2, 2009, a cash distribution of $48.4 million was declared and paid by Northern Border for the fourth quarter of 2008, of which TC PipeLines 50 per cent share was $24.2 million.

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Investing Activities for our Pipeline Systems

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

Year Ended December 31 (millions of dollars)	2008	2007	2006
Great Lakes(a):			
Maintenance	**12.3**	16.7	
Growth			
Great Lakes capital spending	**12.3**	16.7	
Northern Border:			
Maintenance	**8.4**	10.6	10.4
Growth	**12.1**		10.5
Northern Border s capital spending	**20.5**	10.6	20.9
Tuscarora:			
Maintenance	**0.1**	0.1	0.3
Growth	**6.7**	13.1	1.3
Tuscarora s capital spending	**6.8**	13.2	1.6

(a) Great Lakes 2007 capital spending information includes only capital expenditures from February 23 to December 31, 2007.

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.

Great Lakes capital spending is comprised of maintenance capital projects including compressor engine overhauls and pipeline remediation. In 2009, Great Lakes expects to invest approximately $11.8 million for maintenance capital expenditures. No significant growth capital expenditures are planned for 2009.

Northern Border s maintenance capital expenditures decreased $2.2 million in 2008 compared to 2007 due to a decrease in expenditures related to compressor engine overhauls. Growth capital expenditures in 2008 and 2006 were primarily related to spending for the Des Plaines Project and the Chicago III Expansion Project, respectively. In 2009, Northern Border expects to spend approximately $14.2 million for capital expenditures. Maintenance capital expenditures are estimated at $8.2 million and include renewals and replacements of existing facilities. Northern Border plans to spend approximately $6.0 million for growth capital expenditures related to the Des Plaines Project.

In 2008, Tuscarora made capital expenditures of $6.8 million that related primarily to the 2008 Expansion Project compared to $13.2 million last year. In 2009, Tuscarora expects to invest approximately $0.5 million for maintenance capital expenditures. No significant growth capital expenditures are planned for 2009.

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

We believe that our pipeline systems are in substantial compliance with applicable environmental laws and regulations. For additional information regarding environmental matters, see Note 4 of the Partnership s financial statements included elsewhere in this report.

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RELATED PARTY TRANSACTIONS

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to nine years. Great Lakes earned $144.1 million of transportation revenues under these contracts in 2008 ($113.9 million for the period February 23, 2007 to December 31, 2007). This amount represents 50.0 per cent of total revenues earned by Great Lakes in 2008 (48.2 per cent for the period February 23, 2007 to December 31, 2007). $67.0 million of affiliated revenue is included in the Partnership s equity income from Great Lakes in 2008 ($52.9 million for the period February 23, 2007 to December 31, 2007). At December 31, 2008, $12.7 million was included in Great Lakes receivables from affiliates, of which $12.5 million related to the transportation contracts with TransCanada and its affiliates. At December 31, 2007, $11.6 million was included in Great Lakes receivables from affiliates, of which $10.0 million related to the transportation contracts with TransCanada and its affiliates. In November 2008, TransCanada renewed 360 Mdth/d (or 16 per cent) of capacity on Great Lakes system through October 31, 2012.

In August 2008, Northern Border sold its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada for $20.0 million. In connection with this transaction, Northern Border recorded a gain on sale of $16.2 million, of which the Partnership s share was $8.1 million.

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 its affiliates and Northern Border s sale of Bison Pipeline LLC.

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.

We are 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 to 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. Our primary risk management objective is to protect earnings and cash flow, and ultimately unitholder value. We do not use financial instruments for trading purposes.

In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* (SFAS No. 133) 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.

MARKET RISK AND INTEREST RATE RISK

From time to time, and in order to finance our business and that of our pipeline systems, the Partnership and our pipeline systems issue debt to invest in growth opportunities and provide for ongoing operations. The issuance of debt exposes the Partnership and our pipeline systems to market risk from changes in interest rates which affect earnings and the value of the financial instruments we hold.

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The Partnership and our pipeline systems use derivatives as part of our overall risk management policy to manage exposures to market risk resulting from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Swaps contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Partnership and our pipeline systems enter into interest rate swaps to mitigate the impact of changes in interest rates.

- Options contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period. The Partnership and our pipeline systems enter into option agreements to mitigate the impact of changes in interest rates.

Interest rate risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in the market interest rates. Our interest rate exposure results from our Senior Credit Facility, which is subject to variability in London Interbank Offered Rate (LIBOR) interest rates. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk. The notional amount hedged at December 31, 2008 was $475.0 million (2007 - $400.0 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 at 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 is 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, 2008, the fair value of the Partnership s interest rate swaps and options accounted for as hedges was negative $31.7 million (2007 negative $9.8 million), of which $11.8 million is classified as a current liability (2007 - $2.5 million). The fair value of the interest rate swaps and options is calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change.

At December 31, 2008, we had $475.0 million (2007 - $507.0 million) outstanding on our Senior Credit Facility. Utilizing the conditions of the interest rate swaps and options, if LIBOR interest rates hypothetically increased or decreased by one per cent (100 basis points) compared to the rates in effect as of December 31, 2008, our annual interest expense for the year ended December 31, 2008 would be unchanged, as all of our outstanding debt at December 31, 2008 was hedged using interest rates swaps and options.

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, 2008, 71 per cent of Northern Border s outstanding debt was at fixed rates (2007 73 per cent). 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 by one per cent (100 basis points) compared with rates in effect as of December 31, 2008, Northern Border s annual interest expense would increase and its net income would decrease by approximately $0.6 million (2007 - $0.8 million); and if interest rates hypothetically decreased by one per cent (100 basis points) compared with rates in effect as of December 31, 2008, Northern Border s annual interest expense would decrease and its net income would increase by approximately $0.4 million (2007 - $1.1 million).

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

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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.

Counterparty credit risk represents the financial loss that the Partnership and our pipeline systems would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Partnership or its pipeline systems. Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consist primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets. At December 31, 2008, the Partnership s maximum counterparty credit exposure consisted of accounts receivable of $2.9 million.

The Partnership and our pipeline systems have significant credit exposure to financial institutions as they provide committed credit lines and critical liquidity in the interest rate derivative market, as well as letters of credit to mitigate exposures to non-creditworthy parties. During the deterioration of global financial markets in 2008, we continued to closely monitor the creditworthiness of our counterparties, including financial institutions. Overall, we do not believe the Partnership and our pipeline systems have any significant concentrations of counterparty credit risk.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they fall due. Our approach to managing liquidity risk is to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation. At December 31, 2008, the Partnership has a committed revolving bank line of $250.0 million maturing in December 2011. As of December 31, 2008, no draws were made on this facility. In addition, at December 31, 2008, Northern Border has a committed revolving bank line of $250.0 million maturing in April 2012. As of December 31, 2008, $181.0 million was drawn on this facility.

Northern Border has $200.0 million of senior notes due in 2009. It intends to refinance the senior notes with a combination of equity contributions from its partners, fixed-rate and short-term variable-rate debt.

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 $0.6 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.

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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 Securities and Exchange Commission s (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, 2008, 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, 2008 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-2 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

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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	46	Chairman, Chief Executive Officer and Director
Mark A.P. Zimmerman	44	President
Jack F. Jenkins-Stark	58	Independent Director
David L. Marshall	69	Independent Director
Walentin (Val) Mirosh	63	Independent Director
Gregory A. Lohnes	52	Director
Kristine L. Delkus	51	Director
Steven D. Becker	58	Director
Terry C. Ofremchuk	58	Vice-President, Taxation
Rhonda L. Amundson	47	Treasurer
Donald J. DeGrandis	60	Secretary
Amy W. Leong	41	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 May 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.

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 Special Advisor to the President and Chief Operating Officer. Prior to April 2008, Mr. Mirosh was Vice-President and President of Olefins and Feedstocks, a division of NOVA Chemicals Corporation (commodity chemical company), positions he has held since July 2003. Mr. Mirosh is also a director of 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.

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

Ms. Amundson was appointed Treasurer of the general partner in December 2008. Ms. Amundson s principal occupation is Manager, Capital Markets of 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.

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

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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, 2008.

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.

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The following table summarizes the salary allocated to and paid by us in 2008 and 2007 for our principal executive officer, president and principal financial officer. 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**	**Total (1)**
Russell K. Girling, Chief Executive Officer	**2008**	**68,251**	**55,733**	**55,733**
	2007	60,250	60,973	60,973
Mark A.P. Zimmerman, President	**2008**	**108,753**	**88,808**	**88,808**
	2007	102,500	103,729	103,729
Amy W. Leong, Controller and Principal Financial Officer	**2008**	**27,390**	**22,366**	**22,366**
	2007	16,475	16,673	16,673

(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, 2008 and 2007 noon buying rates of 0.8166 and 1.0120, 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 .35 for benefits in 2008 (2007 factor of .38) and a factor of .30 for incentive compensation in 2008 (2007 factor of .30). The total amount reimbursed for benefits and incentive compensation were $610,801 in 2008 and $548,665 in 2007 for all employees providing services to the Partnership, including the named officers in the above table.

Compensation Committee Report

Neither we, nor our general partner, has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

The Board of Directors of TC PipeLines GP, Inc:
Russell K. Girling
Jack F. Jenkins-Stark
David L. Marshall
Walentin Mirosh
Gregory A. Lohnes
Kristine L. Delkus

Steven D. Becker

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Independent Director Compensation

Independent Director Compensation(1) **For the year ended December 31, 2008 (in dollars)**	**Earned or Paid in Cash (4)**	**Unit Awards (5)**	**All Other Compensation (6)**	**Total**
David L. Marshall (2)	62,500	17,283	1,713	81,496
Jack F. Jenkins-Stark (3)	65,000	17,283	2,460	84,743
Walentin (Val) Mirosh	58,500	17,283	1,713	77,496

(1) Employee directors do not receive any additional compensation for serving on the board of directors of our general partner; therefore, no amounts are shown for Russell K. Girling, Gregory A. Lohnes, Kristine L. Delkus and Steven D. Becker. Amounts paid as reimbursable business expenses to each director for attending board functions are not reflected in this table. Our general partner does not consider the directors reimbursable business expenses for attending board functions and other business expenses required to perform board duties to have a personal benefit and thus be considered a perquisite.

(2) Chairman of the Audit Committee

(3) Lead Director and Chairman of the Conflicts Committee

(4) Pursuant to the Deferred Share Unit Plan for Non-Employee Directors, Jack F. Jenkins-Stark elected to receive half of his fees ($32,500) in Deferred Share Units. Due to this election, 1,098 Deferred Share Units were credited to Mr. Jenkins-Stark's account in 2008, all of which were outstanding at December 31, 2008.

(5) Amounts presented reflect the compensation expense recognized related to the Deferred Share Units granted during 2008 under the Deferred Share Unit Plan for Non-Employee Directors. On January 17, 2008, each independent director was granted 540 Deferred Share Units, all of which were outstanding at December 31, 2008. These compensation amounts were calculated using an estimated common unit price of $32.00 with no allowance for forfeiture. At December 31, 2008, David L. Marshall, Jack F. Jenkins-Stark and Walentin (Val) Mirosh held 590, 1,721 and 590 Deferred Share Units, respectively. The fair value of Deferred Share Units held by Mr. Marshall, Mr. Jenkins-Stark and Mr. Mirosh at December 31, 2008 was $18,880, $55,072 and $18,880, respectively.

(6) Amounts presented reflect Deferred Share Units credited to each independent director's account equal to the distributions payable on the Deferred Share Units previously granted or credited. In this regard, David L. Marshall and Walentin (Val) Mirosh were credited 50 Deferred Share Units in 2008, while Jack F. Jenkins-Stark was credited 83 Deferred Share Units. All Deferred Share Units credited during 2008 were outstanding at December 31, 2008.

Cash 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 $50,000 per annum, of which $20,000 is automatically granted in Deferred Share Units (see Deferred Share Units section below). 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. 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. All fees are paid by the Partnership on a quarterly basis. The independent directors are permitted to elect to receive any portion of their fees in the form of Deferred Share Units pursuant to The TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2007).

Deferred Share Units

The TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2007) was established in 2007 with the first grant occurring in January 2008. In 2008, as part of the retainer fee, each independent director received an annual grant of Deferred Share Units with a value of $20,000, which has been increased to a value of $30,000 commencing January 1, 2009.

At the time of grant, the value of a Deferred Share Unit is equal to the market value of a common unit at the time the independent director is credited with the units. The value of a Deferred Share Unit when redeemed is equivalent to the market value of a common unit at the time the redemption takes place. Deferred Share Units cannot be redeemed

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until the director ceases to be a member of the Board. Directors may redeem Deferred Share Units for cash or common units at their option.

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 26, 2009 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.

	Amount and Nature of Beneficial Ownership		
Name and Business Address	**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		1,872	*
Walentin (Val) Mirosh (8) 10th Floor, 1000-7th Avenue SW Calgary, Alberta T2P 5L5		1,872	*
Jack F. Jenkins-Stark (9) 1999 Harrison Street, Suite 500 Oakland, CA 94612	4,933	3,035	*
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 people)			*

(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.

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(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) No common units are currently held 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 one named director 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 521,170 options and 22,525 shares of TransCanada; Kristine L. Delkus holds 108,423 options and 4,360 shares of TransCanda; Steven D. Becker holds 81,343 options and 3,089 shares of TransCanada; Terry C. Ofremchuk holds 5,250 options and 5,667 shares of TransCanada; Gregory A. Lohnes holds 92,029 options and 13,503 shares of TransCanada; Amy W. Leong holds 5,600 options and 3,658 shares of TransCanada; Donald J. DeGrandis holds 15,800 options and 769 shares of TransCanada; Mark A.P. Zimmerman holds 30,451 options and 383 shares of TransCanada; and Rhonda L. Amundson holds 6,100 options of TransCanada and 3,063 shares of TransCanada. The directors and executive officers as a group hold 866,166 options of TransCanada and 57,743 shares of TransCanada. All options listed above are exercisable within 60 days from February 26, 2009.

* Less than one per cent.

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

At February 27, 2009, 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.

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- 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 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 $2.1 million for the year ended December 31, 2008 (2007 - $1.9 million; 2006 - $1.2 million).

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.

TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became the operator of Northern Border effective April 1, 2007. The operator of Great Lakes became a wholly-owned subsidiary of TransCanada through TransCanada s acquisition of Great Lakes Gas Transmission Company on February 22, 2007. TCNB also became the operator of Tuscarora, as part of the December 19, 2006 acquisition of an additional 49 per cent general partner interest in Tuscarora. TransCanada and its affiliates provide capital and operating services to Great Lakes, Northern Border and Tuscarora (together, our pipeline systems). TransCanada and its affiliates incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, property and liability insurance costs, and transition costs. Total costs charged to our pipeline systems for the years ended December 31, 2008 and 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at December 31, 2008 and 2007 are summarized in the following tables:

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Year ended December 31 (millions of dollars)	2008	2007 (1)
Costs charged by TransCanada and its affiliates:		
Great Lakes	**34.3**	25.6
Northern Border (2)	**30.5**	22.5
Tuscarora	**3.7**	1.8
Impact on the Partnership s net income:		
Great Lakes	**14.2**	11.2
Northern Border	**12.9**	11.0
Tuscarora	**2.7**	0.9

(1) The amounts disclosed for Great Lakes are for the period February 23 to December 31, 2007. The amounts disclosed for Northern Border are for the period April 1 to December 31, 2007.

(2) Northern Border s costs charged by TransCanada and its affiliates include $2.0 million of charges related to Bison Pipeline LLC through the effective date of the sale.

December 31 (millions of dollars)	2008	2007
Amount owed to TransCanada and its affiliates:		
Great Lakes	**4.5**	1.9
Northern Border	**2.8**	3.0
Tuscarora	**0.8**	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to nine years. Great Lakes earned $144.1 million of transportation revenues under these contracts in 2008 ($113.9 million for the period February 23, 2007 to December 31, 2007). This amount represents 50.0 per cent of total revenues earned by Great Lakes for in 2008 (48.2 per cent for the period February 23, 2007 to December 31, 2007). $67.0 million of affiliated revenue is included in the Partnership s equity income from Great Lakes in 2008 ($52.9 million for the period February 23, 2007 to December 31, 2007). At December 31, 2008, $12.7 million was included in Great Lakes receivables from affiliates, of which $12.5 million related to the transportation contracts with TransCanada and its affiliates. At December 31, 2007, $11.6 million was included in Great Lakes receivables from affiliates, of which $10.0 million related to the transportation contracts with TransCanada and its affiliates. In November 2008, TransCanada renewed 360 Mdth/d (or 16 per cent) of capacity on Great Lakes system through October 16, 2012.

In August 2008, Northern Border sold its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada for $20.0 million. In connection with this transaction, Northern Border recorded a gain on sale of $16.2 million, of which the Partnership s share is $8.1 million.

Northern Border s Des Plaines Project consists of the construction, ownership and operation of interconnect facilities near Joliet, Illinois. In June 2008, in connection with the Des Plaines Project, Northern Border and ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada, have entered into an Interconnect Agreement, which provides that Northern Border will reimburse ANR for the cost of the interconnect facilities to be owned by ANR. In June, Northern Border paid ANR $0.5 million and it is estimated that additional costs to complete the interconnect will be $0.1 million. Northern Border will be responsible for the final costs to construct the interconnect and any difference between the final actual costs and the estimated amounts paid will be remitted by or refunded to Northern Border.

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Item 14. Principal Accounting Fees and Services

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

Year Ended December 31	2008	2007
Audit Fees (1)	**284,303**	310,745
Audit Related Fees (2)	**12,947**	170,014
Tax Fees (3)		
All Other Fees (3)		

(1) Audit Fees include services performed related to Sarbanes-Oxley Act reporting requirements, and includes services for the statutory audit of Tuscarora.

(2) Audit Related Fees in 2007 related primarily 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 2008 or 2007.

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.

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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	General Partnership Interest Purchase Agreement dated as of December 20, 2007 by and between TCPL Tuscarora Ltd. and TC Pipelines Tuscarora LLC. (Exhibit 2.5 to TC PipeLines, LP s Form 10-K filed on February 28, 2008 (File No. 000-26091)).
*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. (Exhibit 3.1.1 to TC PipeLines, LP s Form 10-K filed on February 28, 2008 (File No. 000-26091)).
*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.

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	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)).
*10.3.1	First Amendment to Amended and Restated Revolving Credit Agreement dated as of July 31, 2008 between Northern Border Pipeline Company and the lenders named therein. (Exhibit 10.2 to TC PipeLines, LP s Form 10-Q filed on November 3, 2008 (File No. 000-26091)).
*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	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)).
*10.8	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)).
*10.9	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)).
10.9.1	Amendment No. 1 to Northern Border Pipeline Company Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated as of April 22, 2008.
*10.10	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)).
10.10.1	First Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated as of June 21, 2007.
10.10.2	Second Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated as of December 31, 2007.
10.10.3	Third Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated as of December 31, 2008.

*10.11	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)).
*10.12	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)).
*10.13	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)).
*10.14	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)).
*10.15	Transportation Service Agreement FT 4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 7, 2007. (Exhibit 10.20 to TC PipeLines, LP s Form 10-K filed on February 28, 2008 (File No. 000-26091)).
*10.16	Transportation Service Agreement FT 8742 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 6, 2007. (Exhibit 10.21 to TC PipeLines, LP s Form 10-K filed on February 28, 2008 (File No. 000-26091)).
*10.17	Transportation Service Agreement FT8945 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated February 1, 2008. (Exhibit 10.1 to TC PipeLines, LP s Form 10-Q filed on April 30, 2008 (File No. 000-26091)).
*10.18	Transportation Service Agreement FT9141 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 12, 2008. (Exhibit 10.1 to TC PipeLines, LP s Form 10-Q filed on August 5, 2008 (File No. 000-26091)).
*10.19	Transportation Service Agreement FT9158 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 14, 2008. (Exhibit 10.2 to TC PipeLines, LP s Form 10-Q filed on August 5, 2008 (File No. 000-26091)).
10.20	Transportation Service Agreement FT11544 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 3, 2008.
10.21	Transportation Service Agreement FT11701 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 26, 2008.
10.22	Transportation Service Agreement FT4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 26, 2008.
*10.23	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)).
*10.24	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)).
#10.25	The TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), dated October 18, 2007, as amended on December 10, 2008.

*10.26	Membership Interest Purchase Agreement as of August 28, 2008, by and between Northern Border Pipeline Company and TransCanada Pipeline USA Ltd. (Exhibit 10.1 to TC PipeLines, LP s Form 10-Q filed on November 3, 2008 (File No. 000-26091)).
*10.27	Interconnect Agreement between ANR Pipeline Company and Northern Border Pipeline Company, dated June 9, 2008. (Exhibit 10.3 to TC PipeLines, LP s Form 10-Q filed on August 5, 2008 (File No. 000-26091)).
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, 2007 and 2006. (Exhibit 99.1 to TC PipeLines, LP s Form 10-Q filed on April 30, 2008 (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.

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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 27th day of February 2009.

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 27, 2009
/s/	Amy W. Leong Amy W. Leong	Controller and Principal Financial Officer	February 27, 2009
/s/	Gregory A. Lohnes Gregory A. Lohnes	Director	February 27, 2009
/s/	Kristine L. Delkus Kristine L. Delkus	Director	February 27, 2009
/s/	Steven D. Becker Steven D. Becker	Director	February 27, 2009
/s/	Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 27, 2009
/s/	Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	February 27, 2009

/s/	David L. Marshall		
	David L. Marshall	Director	February 27, 2009

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TC PIPELINES, LP

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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 of TC PipeLines, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2008 and 2007, 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, 2008. We also have audited TC PipeLines, LP internal control over financial reporting as of December 31, 2008, 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 these consolidated financial statements, 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 Annual Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Partnership s internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 company; (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 company are being made only in accordance with authorizations of management and directors of the company; 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, 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, 2008 and 2007, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also in our opinion, TC PipeLines, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Calgary, Canada
February 26, 2009

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TC PIPELINES, LP

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2008**	**2007**
Assets		
Current Assets		
Cash and cash equivalents	**8.4**	7.5
Accounts receivable and other	**3.4**	4.2
	11.8	11.7
Investment in Great Lakes *(Note 3)*	**704.5**	721.1
Investment in Northern Border *(Note 4)*	**514.8**	541.9
Plant, property and equipment *(Note 6)*	**134.2**	134.1
Goodwill *(Note 7)*	**81.7**	81.7
Other assets	**1.5**	2.1
	1,448.5	1,492.6
Liabilities and Partners Equity		
Current Liabilities		
Bank indebtedness		1.4
Accounts payable	**2.2**	4.8
Accrued interest	**2.1**	3.0
Current portion of long-term debt *(Note 8)*	**4.4**	4.6
Current portion of fair value of derivative contracts *(Note 17)*	**11.8**	2.5
	20.5	16.3
Fair value of derivative contracts and other *(Note 17)*	**20.0**	7.4
Long-term debt *(Note 8)*	**532.4**	568.8
	572.9	576.2
Partners Equity *(Note 9)*		
Common units	**891.4**	892.3
General partner	**19.1**	19.1
Accumulated other comprehensive loss	**(34.9)**	(11.3)
	875.6	900.1
	1,448.5	1,492.6

Subsequent events *(Note 19)*

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

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TC PIPELINES, LP

CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 (millions of dollars except per common unit amounts)	2008	2007	2006
Equity income from investment in Great Lakes *(Note 3)*	**57.3**	49.0	
Equity income from investment in Northern Border *(Note 4)*	**65.3**	61.2	56.6
Equity income from investment in Tuscarora *(Note 5)*			5.9
Transmission revenues	**31.6**	27.2	0.9
Operating expenses	**(9.5)**	(8.3)	(2.7)
Depreciation *(Note 6)*	**(6.9)**	(6.3)	(0.2)
Financial charges, net and other *(Note 10)*	**(30.1)**	(33.8)	(15.8)
Net income	**107.7**	89.0	44.7
Net income allocation			
Common units	**95.9**	81.3	41.8
General partner	**11.8**	7.7	2.9
	107.7	89.0	44.7
Net income per common unit *(Note 11)*	**$ 2.75**	$ 2.51	$ 2.39
Weighted average common units outstanding *(millions)*	**34.9**	32.3	17.5
Common units outstanding, end of the period *(millions)*	**34.9**	34.9	17.5

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	2008	2007	2006
Net income	**107.7**	89.0	44.7
Other comprehensive (loss)/income			
Change associated with current period hedging transactions *(Note 17)*	**(22.0)**	(11.4)	1.6
Change associated with current period hedging transactions of investees	**(1.6)**	(1.7)	(0.5)
	(23.6)	(13.1)	1.1
Total comprehensive income	**84.1**	75.9	45.8

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

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TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	2008	2007	2006
Cash Generated From Operations			
Net income	**107.7**	89.0	44.7
Depreciation *(Note 6)*	**6.9**	6.3	0.2
Amortization of other assets *(Note 10)*	**0.5**	0.4	0.9
Non-controlling interests *(Note 7)*		0.2	
Increase in long-term liabilities	**0.1**		
Equity allowance for funds used during construction	**(0.2)**	(0.2)	
(Increase)/decrease in operating working capital *(Note 13)*	**(1.4)**	0.6	(0.3)
	113.6	96.3	45.5
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Great Lakes	**16.6**	12.3	
Northern Border	**25.4**	25.1	23.8
Tuscarora			1.8
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)
Increase in cash due to the consolidation of Tuscarora			2.6
Capital expenditures	**(6.8)**	(13.2)	
Other assets		(1.1)	(1.9)
(Increase)/decrease in investing working capital *(Note 13)*	**(2.7)**	2.3	0.6
	32.5	(719.0)	(381.4)
Financing Activities			
Distributions paid *(Note 12)*	**(108.6)**	(86.7)	(43.5)
Equity issuances, net		607.0	
Long-term debt issued *(Note 8)*	**4.0**	171.5	707.0
Long-term debt repaid *(Note 8)*	**(40.6)**	(66.2)	(325.9)
	(145.2)	625.6	337.6
Increase in cash and cash equivalents	**0.9**	2.9	1.7
Cash and cash equivalents, beginning of year	**7.5**	4.6	2.9
Cash and cash equivalents, end of year	**8.4**	7.5	4.6
Interest payments made	**24.4**	34.3	13.9

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

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TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS EQUITY

	Common Units		General Partner	Accumulated Other Comprehensive Loss (1)	Partners Equity	
	(millions of units)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of units)	(millions of dollars)
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
Net income		95.9	11.8			107.7
Distributions paid		(96.8)	(11.8)			(108.6)
Other comprehensive loss				(23.6)		(23.6)
Partners equity at December 31, 2008	**34.9**	**891.4**	**19.1**	**(34.9)**	**34.9**	**875.6**

(1) TC PipeLines, LP uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at December 31, 2008, the amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in the next 12 months is $11.8 million, which will be offset by a reduction to interest expense of a similar amount.

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TC PIPELINES, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiaries, including TC GL Intermediate Limited Partnership, TC PipeLines Intermediate Limited Partnership and TC Tuscarora 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, a wholly-owned subsidiary of TransCanada, to a terminus in 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, 2008. 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, 2008.

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, 2008 and 2007 and the results of its operations, cash flows and changes in partners equity for the years ended December 31, 2008, 2007 and 2006. 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 (GAAP) 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.

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(c) Cash and Cash Equivalents

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 of Tuscarora 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. Amounts included in construction work in progress are not amortized until transferred into service.

The Partnership assesses its long-lived assets for impairment based on Statement of Financial Accounting Standards (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, impairment is recognized to the extent the carrying amount exceeds its fair value.

(e) Partners Equity

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

(f) Revenue Recognition

Transmission revenues relate solely to Tuscarora, and are recognized in the period in which the service is provided. When a rate case is pending final FERC approval, a portion of the revenue collected is subject to possible refund. As of December 31, 2008 and 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 hedging instruments must be designated as hedges and be effective to qualify for hedge accounting. 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.

Effective January 1, 2008, the Partnership adopted the provisions of SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). Under this standard, these financial assets and liabilities that are recorded at fair value on a recurring basis are categorized into one of three categories based upon a fair value hierarchy. The Partnership has

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classified all of its derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices.

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 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

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 may be recorded that would not be recorded under GAAP 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, 2008 and 2007, the Partnership has no regulatory assets or liabilities.

(l) Debt Issuance Costs

Costs related to the issuance of debt are deferred and amortized using the effective interest rate method over the term of the related debt.

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. On the same day, a wholly-owned subsidiary of TransCanada acquired 100 per cent ownership of 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 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 $57.3 million for the year ended December 31, 2008 ($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, 2008 and the period February 23, 2007 to December 31, 2007.

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The following sets out summarized financial information for Great Lakes as at December 31, 2008 and 2007 and for the year ended December 31, 2008 and for the period February 23, 2007 to December 31, 2007:

Summarized Consolidated Great Lakes Balance Sheet

December 31 (millions of dollars)	**2008**	**2007**
Assets		
Cash and cash equivalents	**1.6**	32.0
Other current assets	**80.2**	55.5
Plant, property and equipment, net	**923.4**	969.2
	1,005.2	1,056.7
Liabilities and Partners Equity		
Current liabilities	**43.0**	50.7
Deferred credits and other	**2.3**	0.4
Long-term debt, including current maturities	**430.0**	440.0
Partners capital	**529.9**	565.6
	1,005.2	1,056.7

Summarized Consolidated Great Lakes Income Statement

December 31 (millions of dollars)	**2008**	**For the period February 23 to December 31, 2007**
Transmission revenues	**287.1**	236.2
Operating expenses	**(67.1)**	(53.7)
Depreciation	**(58.5)**	(49.4)
Financial charges, net and other	**(32.6)**	(27.6)
Michigan business tax	**(5.5)**	
Net income	**123.4**	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 $10.0 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 $65.3 million for the year ended December 31, 2008 (2007 - $61.2 million; 2006 - $56.6 million). Northern Border had no undistributed earnings for the years ended December 31, 2008, 2007 and 2006.

On February 2, 2009, Northern Border received a Notice of Violation from the United States Environmental Protection Agency alleging that Northern Border was in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on its system. At this time, Northern Border is unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty, but does not expect such amounts to be material to its financial condition.

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The following sets out summarized financial information for Northern Border as at December 31, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006:

Summarized Northern Border Balance Sheet

December 31 (millions of dollars)	**2008**	**2007**
Assets		
Cash and cash equivalents	**21.6**	22.9
Other current assets	**39.1**	39.8
Plant, property and equipment, net	**1,390.8**	1,428.3
Other assets	**24.5**	23.9
	1,476.0	1,514.9
Liabilities and Partners Equity		
Current liabilities	**48.7**	53.4
Deferred credits and other	**11.2**	8.1
Long-term debt, including current maturities	**630.4**	615.3
Partners equity		
Partners capital	**791.4**	840.5
Accumulated other comprehensive loss	**(5.7)**	(2.4)
	1,476.0	1,514.9

Summarized Northern Border Income Statement

Year ended December 31 (millions of dollars)	**2008**	**2007**	**2006**
Transmission revenues	**293.1**	309.4	310.9
Operating expenses	**(78.0)**	(83.5)	(81.0)
Depreciation	**(61.1)**	(60.7)	(58.7)
Financial charges, net and other *(Note 14)*	**(21.8)**	(41.1)	(41.3)
Net income	**132.2**	124.1	129.9

NOTE 5 INVESTMENT IN TUSCARORA

The Partnership wholly-owns Tuscarora. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. 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. Tuscarora is operated by TCNB. Tuscarora is regulated by the FERC.

The Partnership recorded net income from Tuscarora under the consolidation method of $15.0 million for the year ended December 31, 2008 (2007 - $11.4 million; $0.4 million for the period December 20, 2006 to December 31, 2006). TC PipeLines equity income from its investment in Tuscarora amounted to $5.9 million for the period January 1, 2006 to December 19, 2006.

For the year ended December 31, 2008, the following customers contributed more than 10 per cent of Tuscarora s revenue: Sierra Pacific Power Company (75 per cent), and Southwest Gas Company (11 per cent). For the year ended December 31, 2007, the following customers contributed 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).

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The following sets out summarized financial information for Tuscarora as at December 31, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006:

Summarized Tuscarora Balance Sheet

December 31 (millions of dollars)	2008	2007
Assets		
Cash and cash equivalents		6.2
Other current assets	**3.1**	2.6
Plant, property and equipment, net	**134.2**	134.1
Other assets	**0.3**	0.5
	137.6	143.4
Liabilities and Partners Equity		
Current liabilities	**2.0**	6.1
Long-term debt, including current maturities	**61.8**	66.4
Partners capital	**73.8**	70.9
	137.6	143.4

Summarized Tuscarora Income Statement

Year ended December 31 (millions of dollars)	2008	2007	2006
Transmission revenues	**31.6**	27.2	29.5
Operating expenses	**(5.4)**	(4.9)	(4.7)
Depreciation	**(6.9)**	(6.3)	(6.2)
Financial charges, net and other	**(4.3)**	(4.4)	(5.3)
Net income	**15.0**	11.6	13.3

Summarized Tuscarora Cash Flow Statement

Year ended December 31 (millions of dollars)	2008	2007	2006
Cash flows provided by operating activities	**21.5**	17.6	19.9
Cash flows used in investing activities	**(9.4)**	(10.9)	(0.9)
Cash flows used in financing activities	**(18.3)**	(3.3)	(20.6)
(Decrease)/increase in cash and cash equivalents	**(6.2)**	3.4	(1.6)
Cash and cash equivalents, beginning of year	**6.2**	2.8	4.4
Cash and cash equivalents, end of year		6.2	2.8

NOTE 6 PLANT, PROPERTY AND EQUIPMENT

	2008			2007	
	Accumulated	Net Book		Accumulated	Net Book

December 31 (millions of dollars)	Cost	Depreciation	Value	Cost	Depreciation	Value
Tuscarora						
Pipeline	**146.6**	**57.9**	**88.7**	146.6	53.1	93.5
Compression	**45.1**	**7.0**	**38.1**	25.0	5.5	19.5
Metering and other	**11.0**	**3.6**	**7.4**	11.0	3.1	7.9
Under construction				13.2		13.2
	202.7	**68.5**	**134.2**	195.8	61.7	134.1

NOTE 7 ACQUISITIONS

Great Lakes

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes. The total purchase price was $942.4 million 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. 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 acquisition with a draw on its senior credit facility.

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.

Pro forma financial information for the Great Lakes acquisition

The following unaudited Partnership pro forma financial information for the years ended December 31, 2008 and 2007 has been prepared as if the Great Lakes acquisition mentioned above occurred on January 1, 2006:

Year ended December 31 (millions of dollars except per unit amounts)		**2007**		**2006**
Pro forma equity income from investment in Great Lakes		59.6		56.8
Pro forma net income		99.6		93.7
Pro forma net income per common unit	$	2.63	$	2.52

Tuscarora

On December 31, 2007, the Partnership acquired a two per cent general partner interest in Tuscarora, thereby making it a wholly-owned subsidiary. 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.

The entire goodwill balance of $81.7 million as at December 31, 2008 and 2007 relates to acquisitions of general partner interests in Tuscarora.

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.

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NOTE 8 CREDIT FACILITIES AND LONG-TERM DEBT

December 31 (millions of dollars)	2008	2007
Senior Credit Facility	**475.0**	507.0
7.13% Series A Senior Notes due 2010	**51.3**	54.5
7.99% Series B Senior Notes due 2010	**5.0**	5.5
6.89% Series C Senior Notes due 2012	**5.5**	6.4
	536.8	573.4

The Partnership has a revolving credit and term loan agreement (Senior Credit Facility) with a banking syndicate. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. In 2008, $13.0 million of the senior term loan was repaid (2007 - $18.0 million), leaving $475.0 million outstanding under the senior term loan at December 31, 2008. No amount is outstanding under the revolving portion of the Senior Credit Facility at December 31, 2008 (2007 - $19.0 million), leaving $250.0 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 London Interbank Offered Rate (LIBOR) or the prime rate plus, in either case, an applicable margin. There was $475.0 million outstanding under the Senior Credit Facility at December 31, 2008 (2007 - $507.0 million). The underlying interest rate on the Senior Credit Facility averaged 3.75 per cent for the year ended December 31, 2008 (2007 6.01 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.15 per cent for the year ended December 31, 2008 (2007 5.55 per cent). Prior to hedging activities, the interest rate was 2.67 per cent at December 31, 2008 (2007 5.62 per cent). At December 31, 2008, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

Series A, B and C Senior Notes are secured by Tuscarora s transportation contracts, supporting agreements and substantially all of Tuscarora s property. The note purchase agreements contain 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)	
2009	4.4
2010	53.5
2011	475.8
2012	3.1
	536.8

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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, 2008, Partners equity includes 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, 2008 (December 31, 2007 7.7 per cent).

NOTE 10 FINANCIAL CHARGES, NET AND OTHER

Year ended December 31 (millions of dollars)	2008	2007	2006
Interest expense on long-term debt	**23.1**	35.1	14.8
Interest expense on short-term debt	**0.3**	0.3	0.3
Capitalized interest	**(0.2)**	(0.2)	
Loss/(gain) on interest rate swaps and options	**6.9**	(1.4)	
Interest income	**(0.5)**	(0.9)	(0.4)
Amortization of other assets	**0.5**	0.4	0.9
Other		0.5	0.2
	30.1	33.8	15.8

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, plus 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)	2008	2007	2006
Net income	**107.7**	89.0	44.7
Net income allocated to general partner			
General partner interest	**(2.1)**	(1.8)	(0.9)
Incentive distribution income allocation	**(9.7)**	(5.9)	(2.0)
	(11.8)	(7.7)	(2.9)
Net income allocable to common units	**95.9**	81.3	41.8
Weighted average common units outstanding *(millions)*	**34.9**	32.3	17.5
Net income per common unit	**$ 2.75**	$ 2.51	$ 2.39

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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 $0.705 per common 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 common unit. For the year ended December 31, 2008, the Partnership distributed $2.775 per common unit (2007 - $2.565 per common unit; 2006 - $2.325 per common unit). The distributions for the year ended December 31, 2008 included incentive distributions to the general partner in the amount of $9.7 million (2007 - $5.9 million; 2006 - $2.0 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 CHANGE IN WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2008**	**2007**
(Decrease)/increase in bank indebtedness	**(1.4)**	1.4
Decrease/(increase) in accounts receivable and other	**0.8**	(1.7)
(Decrease)/increase in accounts payable	**(2.6)**	1.5
(Decrease)/increase in accrued interest	**(0.9)**	1.7
	(4.1)	2.9
(Increase)/decrease in investing working capital	**(2.7)**	2.3
(Increase)/decrease in operating working capital	**(1.4)**	0.6

NOTE 14 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 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 $2.1 million for the year ended December 31, 2008 (2007 - $1.9 million; 2006 - $1.2 million).

TCNB became the operator of Northern Border effective April 1, 2007. The operator of Great Lakes became a wholly-owned subsidiary of TransCanada through TransCanada s acquisition of Great Lakes Gas Transmission Company on February 22, 2007. TCNB also became the operator of Tuscarora, as part of the December 19, 2006 acquisition of an additional 49 per cent general partner interest in Tuscarora. TransCanada and its affiliates provide capital and operating services to Great Lakes, Northern Border and Tuscarora (together, our pipeline systems). TransCanada and its affiliates incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, property and liability insurance costs, and transition costs.

Total costs charged to our pipeline systems for the years ended December 31, 2008 and 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at December 31, 2008 and 2007 are summarized in the following tables:

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Year ended December 31 (millions of dollars)	2008	2007 (1)
Costs charged by TransCanada and its affiliates:		
Great Lakes	**34.3**	25.6
Northern Border (2)	**30.5**	22.5
Tuscarora	**3.7**	1.8
Impact on the Partnership s net income:		
Great Lakes	**14.2**	11.2
Northern Border	**12.9**	11.0
Tuscarora	**2.7**	0.9

(1) The amounts disclosed for Great Lakes are for the period February 23 to December 31, 2007. The amounts disclosed for Northern Border are for the period April 1 to December 31, 2007.

(2) Northern Border s costs charged by TransCanada and its affiliates include $2.0 million of charges related to Bison Pipeline LLC through the effective date of the sale.

December 31 (millions of dollars)	2008	2007
Amount owed to TransCanada and its affiliates:		
Great Lakes	**4.5**	1.9
Northern Border	**2.8**	3.0
Tuscarora	**0.8**	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to nine years. Great Lakes earned $144.1 million of transportation revenues under these contracts in 2008 ($113.9 million for the period February 23, 2007 to December 31, 2007). This amount represents 50.0 per cent of total revenues earned by Great Lakes for in 2008 (48.2 per cent for the period February 23, 2007 to December 31, 2007). $67.0 million of affiliated revenue is included in the Partnership s equity income from Great Lakes in 2008 ($52.9 million for the period February 23, 2007 to December 31, 2007). At December 31, 2008, $12.7 million was included in Great Lakes receivables from affiliates, of which $12.5 million related to the transportation contracts with TransCanada and its affiliates. At December 31, 2007, $11.6 million was included in Great Lakes receivables from affiliates, of which $10.0 million related to the transportation contracts with TransCanada and its affiliates.

In August 2008, Northern Border sold its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada for $20.0 million. In connection with this transaction, Northern Border recorded a gain on sale of $16.2 million, of which the Partnership s share is $8.1 million. In the Summarized Northern Border Income Statement provided in Note 4, the gain on sale is included in Financial charges, net and other.

Northern Border s Des Plaines Project consists of the construction, ownership and operation of interconnect facilities near Joliet, Illinois. In June 2008, in connection with the Des Plaines Project, Northern Border and ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada, have entered into an Interconnect Agreement, which provides that Northern Border will reimburse ANR for the cost of the interconnect facilities to be owned by ANR. In June, Northern Border paid ANR $0.5 million and it is estimated that additional costs to complete the interconnect will be $0.1 million. Northern Border will be responsible for the final costs to construct the interconnect and any difference between the final actual costs and the estimated amounts paid will be remitted by or refunded to Northern Border.

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.

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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 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.

NOTE 15 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected financial data for the four quarters of each of 2008 and 2007:

Quarter ended (millions of dollars except per unit amounts)	Mar 31	Jun 30	Sep 30	Dec 31
2008				
Equity income	**38.1**	**22.5**	**31.9**	**30.1**
Transmission revenues	**6.9**	**8.2**	**8.2**	**8.3**
Net income	**33.6**	**19.2**	**28.3**	**26.6**
Net income per common unit	**$ 0.89**	**$ 0.47**	**$ 0.72**	**$ 0.67**
Cash distributions paid	**25.6**	**27.4**	**27.8**	**27.8**
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

NOTE 16 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.

NOTE 17 DERIVATIVE FINANCIAL INSTRUMENTS

The carrying value of cash and cash equivalents, accounts receivable and other, bank indebtedness, accounts payable, accrued interest and other current liabilities 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, 2008 and 2007 are as follows:

	2008		2007	
December 31 (millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Senior Credit Facility	**475.0**	**475.0**	507.0	507.0

Series A Senior Notes	**51.3**	**52.3**	54.5	58.7
Series B Senior Notes	**5.0**	**5.2**	5.5	6.0
Series C Senior Notes	**5.5**	**5.4**	6.4	7.0
	536.8	**537.9**	573.4	578.7

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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.

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $475.0 million at December 31, 2008 (2007 - $400.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap 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 through May 22, 2009 at 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.

Effective January 1, 2008, we adopted the provisions of SFAS No. 157. *Under SFAS No. 157, the financial assets and liabilities that are recorded at fair value on a recurring basis are categorized into one of three categories based upon a fair value hierarchy. We have classified all of our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices.* At December 31, 2008, the fair value of the interest rate swaps and options accounted for as hedges was negative $31.7 million (2007 - negative $9.8 million). In 2008, TC PipeLines recorded interest expense of $6.9 million on the interest rate swaps and options (2007 interest income of $1.4 million).

NOTE 18 ACCOUNTING PRONOUNCEMENTS

The Partnership adopted the provisions of SFAS No. 157 for its financial assets and liabilities measured at fair value on a recurring basis effective January 1, 2008. *Refer to Note 17 for the impact to our financial statements.*

The Financial Accounting Standards Board (FASB) issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157* (Staff Position No. 157-2), in February 2008, which delayed the effective date of SFAS No. 157 for all non-financial assets and liabilities that are measured at fair value on a non-recurring basis until fiscal years beginning after November 15, 2008. These non-financial items include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and asset retirement obligations initially measured at fair value. The effect of adopting Staff Position No. 157-2 is not expected to be material to our results of operations or financial position.

The FASB issued Staff Position No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,* in October 2008, which clarifies the application of SFAS No. 157 in a market that is not active. This Staff Position is effective upon issuance and the Partnership s financial statements were not impacted by this standard.

The FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS No. 159), in February 2007, which permits entities to choose to measure selected financial assets and financial liabilities at fair value for fiscal years beginning on or after November 15, 2007. 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 Partnership has not elected the fair value option for any non-derivative financial assets or liabilities.

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) in June 2007. EITF 07-4 addresses how current period earnings of a Master Limited Partnership 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 conclusion was ratified by the FASB in March 2008 and is effective for fiscal years beginning after December 15, 2008. We are currently reviewing the applicability of EITF 07-4 to our results of operations and financial position.

The FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162), in May 2008. which codifies the sources of accounting principles and the related framework to be utilized in preparing

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financial statements in conformity with GAAP. The requirements of this standard are not expected to have a material impact on our results of operations or financial position.

The FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS No. 161) in March 2008. SFAS No. 161 expands the disclosure requirements for derivative instruments and hedging activities with respect to how and why entities use derivative instruments, how they are accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and the related impact on financial position, financial performance and cash flows. The requirements of this standard will not have a material effect on the Partnership s disclosure as a result of adoption on January 1, 2009.

The FASB issued SFAS No. 141(R), *Business Combinations* (SFAS No. 141(R)), in December 2007, which replaces SFAS No. 141, *Business Combinations* (SFAS No. 141). 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 impact the accounting for business combinations subsequent to January 1, 2009.

NOTE 19 SUBSEQUENT EVENTS

On January 20, 2009, the Board of Directors of the general partner declared the Partnership s 2008 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 13, 2009 to unitholders of record as of January 30, 2009, totaled $27.8 million and was paid in the following manner: $24.6 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $6.1 million to TransCan Northern as holder of 8,678,045 common units), $2.6 million to the general partner as holder of the incentive distribution rights, and $0.6 million to the general partner in respect of its two per cent general partner interest. The cash distribution represents an annual cash distribution of $2.82 per common unit.

Great Lakes declared and paid a distribution of $27.0 million on January 30, 2009, of which the Partnership received its 46.45 per cent share or $12.5 million.

Northern Border declared and paid a distribution of $48.4 million on February 2, 2009, of which the Partnership received its 50 per cent share or $24.2 million.

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Great Lakes Gas Transmission Limited Partnership
Independent Auditors Report

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 (the Partnership) as of December 31, 2008 and 2007, and the related consolidated statements of income and partners capital, and cash flows for the each of the years in the three-year period ended December 31, 2008. 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 audits 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, 2008 and 2007, and the results of their operations and their cash flows for the each of the years in the three year period ended December 31, 2008 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
January 27, 2009

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Great Lakes Gas Transmission Limited Partnership

Consolidated Statements of Income and Partners Capital

Years Ended December 31

(Thousands of Dollars)

		2008	2007	2006
Transportation Revenues				
Affiliated Revenues	$	**144,137**	137,166	161,605
Nonaffiliated Revenues		**142,993**	145,660	110,652
		287,130	282,826	272,257
Operating Expenses				
Operation and Maintenance		**46,276**	42,125	34,083
Depreciation		**58,522**	58,046	57,612
Property and Other Non Income Taxes		**20,788**	22,195	25,965
		125,586	122,366	117,660
Operating Income		**161,544**	160,460	154,597
Other Income (Expense)				
Interest on Long Term Debt		**(34,222)**	(35,096)	(35,970)
Interest Income		**1,299**	2,872	3,513
Other, Net		**318**	65	191
		(32,605)	(32,159)	(32,266)
Income Before Partnership Income Taxes	$	**128,939**	128,301	122,331
Income Tax Expense		**(5,503)**		
Net Income	$	**123,436**	128,301	122,331
Partners Capital				
Balance at Beginning of Year	$	**565,650**	630,849	640,617
Net Income		**123,436**	128,301	122,331
Distributions to Partners		**(159,200)**	(193,500)	(132,099)
Balance at End of Year	$	**529,886**	565,650	630,849

See accompanying notes to consolidated financial statements.

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Great Lakes Gas Transmission Limited Partnership

Consolidated Balance Sheets

As of December 31

(Thousands of Dollars)

		2008	2007
ASSETS			
Current Assets			
Cash and Cash Equivalents	$	**1,637**	31,960
Demand Loan Receivable from Affiliate		**25,467**	
Accounts Receivable (Net of allowance of $250 in 2008 and $800 in 2007)		**26,938**	29,229
Receivable from Affiliates		**12,739**	11,607
Materials and Supplies		**10,307**	11,257
Prepayments		**4,775**	3,424
		81,863	87,477
Gas Utility Plant			
Property, Plant and Equipment		**2,049,160**	2,045,133
Less Accumulated Depreciation		**(1,125,779)**	(1,075,873)
		923,381	969,260
	$	**1,005,244**	1,056,737
LIABILITIES AND PARTNERS CAPITAL			
Current Liabilities			
Current Maturities of Long Term Debt	$	**19,000**	10,000
Accounts Payable		**17,646**	26,468
Payable to Affiliates		**4,467**	1,871
Property Taxes		**8,800**	9,300
Other Non Income Taxes		**2,963**	3,645
Accrued Interest		**8,998**	9,143
Other		**140**	264
		62,014	60,691
Long Term Debt		**411,000**	430,000
Deferred Partnership Income Taxes		**1,927**	
Other Liabilities		**417**	396
Partners Capital		**529,886**	565,650
	$	**1,005,244**	1,056,737

See accompanying notes to consolidated financial statements.

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Great Lakes Gas Transmission Limited Partnership

Consolidated Statements of Cash Flows

Years Ended December 31

(Thousands of Dollars)

	2008	2007	2006
Cash Flow Increase (Decrease) from:			
Operating Activities			
Net Income	$ **123,436**	128,301	122,331
Adjustments to Reconcile Net Income to Operating Cash Flows:			
Depreciation	**58,522**	58,046	57,612
Deferred Income Taxes	**1,927**		
Allowance for Funds Used During Construction	**(310)**	(438)	(386)
Changes in Current Assets and Liabilities:			
Accounts Receivable	**2,291**	(12,902)	17,477
Receivable from Affiliates	**(1,132)**	7,347	(2,233)
Accounts Payable	**(8,822)**	9,889	(15,048)
Payable to Affiliates	**2,596**	(491)	(2,393)
Property and Other Non Income Taxes	**(1,182)**	(8,787)	(2,716)
Other	**(649)**	(5,342)	(3,309)
	176,677	175,623	171,335
Investing Activities			
Investment in Utility Plant	**(12,333)**	(18,804)	(18,953)
Increase in Demand Loan Receivable from Affiliate	**(25,467)**		
Insurance Proceeds			8,122
	(37,800)	(18,804)	(10,831)
Financing Activities			
Repayment of Long Term Debt	**(10,000)**	(10,000)	(10,000)
Distribution to Partners	**(159,200)**	(193,500)	(132,099)
	(169,200)	(203,500)	(142,099)
Change in Cash and Cash Equivalents	**(30,323)**	(46,681)	18,405
Cash and Cash Equivalents:			
Beginning of Year	**31,960**	78,641	60,236
End of Year	$ **1,637**	31,960	78,641
Supplemental Disclosure of Cash Flow Information			
Cash Paid During the Year for Interest (Net of Amounts Capitalized of $115, $184 and $153, Respectively)	$ **34,440**	35,294	36,132

See accompanying notes to consolidated financial statements.

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Great Lakes Gas Transmission Limited Partnership

Notes to Consolidated Financial Statements

Note 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:

Partner (Parent Company)

	Ownership%	
	2008	**2007**
General Partners:		
TransCanada GL, Inc. (TransCanada PipeLines Limited)	**46.45**	46.45
TC GL Intermediate Limited Partnership (TC PipeLines, LP)	**46.45**	46.45
Limited Partner:		
Great Lakes Gas Transmission Company (TransCanada PipeLines Limited)	**7.10**	7.10

On February 22, 2007 (acquisition date), TC PipeLines, LP (TCLP) 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. The Partnership is charged for the salaries, benefits and expenses of the Company and affiliates for services attributable to its operations.

Note 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.

Cash and Cash Equivalents

For purposes of reporting cash flows, the Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents.

Demand Loan Receivable

Effective August 1, 2008, the Partnership entered into a Cash Management Agreement with its affiliate, TransCanada PipeLine USA Ltd. Monies advanced under the agreement are considered to be a loan, accruing interest and repayable on demand.

Under the Partnership s cash management system, the bank notifies the Partnership daily of checks presented for payment against its disbursement account. The Partnership transfers funds from short-term investments or offsets its Demand Loan Receivable from Affiliates 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 $1.6 million and $5.8 million at December 31, 2008 and 2007, respectively.

Fair Value

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.

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Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities as of 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 those estimates.

Regulation

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership s accounting policies conform to Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. There are no significant 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 collection of all or a portion of the outstanding balance is not reasonably assured. 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 contractual amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from customers and interconnecting pipelines at an index price. 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 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 equipment, are depreciated at an annual rate of 2.75%. The remaining assets are depreciated at annual rates ranging from 4% to 20%.

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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 10.49%, 10.25%, and 10.37% for years 2008, 2007, and 2006, respectively.

Asset Retirement Obligations

The Partnership accounts for asset retirement obligations in accordance with SFAS No. 143, Accounting for Asset Retirement Obligations and Financial Accounting Standards Board Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. SFAS 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. 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 fair value of an asset retirement obligation. The Partnership has 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 establish a liability for the obligations.

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 its fair value. Fair values are based on the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Income Taxes

In the third quarter of 2007, the state of Michigan enacted the Michigan Business Tax (MBT), which replaced the Michigan Single Business Tax effective January 1, 2008. The MBT is an income tax levied at the partnership level.

Income taxes, other than the MBT, 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.

Fair Value Measurements

Effective January 1, 2008, the Partnership adopted SFAS No. 157, Fair Value Measurements, which provides guidance on measuring the fair value of assets and liabilities in the financial statements. The effect of adopting SFAS No. 157 did not have a material impact on the Partnership s results of operations or financial position.

Also on January 1, 2008, the Partnership adopted 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. The Partnership has not elected the fair value option for any financial assets or liabilities.

Note 3 Affiliated Company Transactions

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

(In Thousands) Transportation Revenues:	2008	2007	2006
TransCanada and affiliates	**144,137**	135,629	150,067
El Paso and affiliates		1,537	11,538
Interest Income	**453**		

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Affiliated transportation revenues are primarily provided under fixed priced contracts with remaining terms ranging from 1 to 9 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 2008, 2007, and 2006 were $34,261,000, $26,836,000 and $18,022,000, 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.

Note 4 - Debt

	(In Thousands)	
	2008	**2007**
Senior Notes, unsecured, interest due semiannually, principal due as follows:		
8.74% series, due 2009 to 2011	**30,000**	40,000
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
	430,000	440,000
Less current maturities	**19,000**	10,000
Total long term debt less current maturities	**411,000**	430,000

The aggregate estimated fair value of long term debt was $413,148,000 and $525,104,000 for 2008 and 2007, 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 $19,000,000 for each year 2009 through 2013.

Under the most restrictive covenants in the Senior Note Agreements, approximately $232,000,000 of partners capital is restricted as to distributions as of December 31, 2008.

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Note 5 Michigan Business Tax

The Partnership files the Michigan Business Tax (MBT) return on a unitary basis with certain TransCanada affiliates. A tax payment agreement between the Partnership and TransCanada affiliates provides that the Partnership s MBT liability is determined as if a separate return was filed. Under the agreement, the Partnership remits its current MBT liability to an affiliate, accordingly any liability is included in payable to affiliates.

MBT for the year ended December 31, 2008 consists of:

	(In Thousands) 2008
Current	3,576
Deferred	1,927
	5,503

The deferred tax assets and deferred tax liabilities as of December 31, 2008 are as follows:

	(In Thousands) 2008
Deferred tax assets non-regulated utility plant	12,970
Deferred tax liabilities regulated utility plant	(13,345)
Deferred tax liabilities other	(1,552)
Net deferred tax liability	(1,927)

As of December 31, 2008, no valuation allowance is required.

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Independent Auditors Report

Management Committee

Northern Border Pipeline Company:

We have audited the accompanying balance sheets of Northern Border Pipeline Company (the Company) as of December 31, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Omaha, Nebraska

February 24, 2009

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NORTHERN BORDER PIPELINE COMPANY

BALANCE SHEETS

	December 31, 2008		December 31, 2007	
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	21,655	$	22,937
Accounts receivable		32,781		31,307
Related party receivables		386		2,754
Materials and supplies, at cost		4,562		4,205
Prepaid expenses and other		1,421		1,506
Total current assets		60,805		62,709
Property, plant and equipment:				
In service natural gas transmission plant		2,491,977		2,485,607
Construction work in progress		12,366		2,876
Total property, plant and equipment		2,504,343		2,488,483
Less: Accumulated provision for depreciation and amortization		1,113,582		1,060,195
Property, plant and equipment, net		1,390,761		1,428,288
Other assets:				
Regulatory assets (Note 2)		21,678		20,638
Unamortized debt expense		2,311		2,662
Other		484		589
Total other assets		24,473		23,889
Total assets	$	1,476,039	$	1,514,886
LIABILITIES AND PARTNERS EQUITY				
Current liabilities:				
Current maturities of long-term debt (Note 5)	$	200,000	$	
Accounts payable		6,096		7,179
Related party payables		3,852		5,852
Accrued taxes other than income		26,280		27,625
Accrued interest		11,060		11,283
Other		1,455		1,487
Total current liabilities		248,743		53,426
Long-term debt, net of current maturities (Note 5)		430,435		615,286
Deferred credits and other liabilities				
Related party payables		1,507		2,260
Regulatory liabilities (Note 2)		4,741		2,393
Derivative financial instruments (Note 6)		3,633		1,852
Other		1,312		1,616
Total deferred credits and other liabilities		11,193		8,121
Commitments and contingencies (Note 8)				
Partners equity:				
Partners capital		791,376		840,494
Accumulated other comprehensive loss		(5,708)		(2,441)
Total partners equity		785,668		838,053
Total liabilities and partners equity	$	1,476,039	$	1,514,886

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

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NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF INCOME

	Years Ended December 31, 2008	2007 (In thousands)	2006
Operating revenue	$ 293,105	$ 309,376	$ 310,900
Operating expenses			
Operations and maintenance	51,260	54,057	49,500
Depreciation and amortization	61,081	60,733	58,721
Taxes other than income	26,765	29,379	31,541
Operating expenses	139,106	144,169	139,762
Operating income	153,999	165,207	171,138
Interest expense			
Interest expense	40,974	43,082	43,218
Interest expense capitalized	(182)	(11)	(137)
Interest expense, net	40,792	43,071	43,081
Other income (expense)			
Allowance for equity funds used during construction	323	30	192
Gain on sale of assets (Note 11)	16,166		
Other income (Note 10)	2,932	2,427	2,218
Other expense (Note 10)	(426)	(488)	(622)
Other income, net	18,995	1,969	1,788
Net income to partners	$ 132,202	$ 124,105	$ 129,845

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31, 2008	2007 (In thousands)	2006
Net income to partners	$ 132,202	$ 124,105	$ 129,845
Other comprehensive income:			
Changes associated with hedging transactions	(3,267)	(3,419)	(1,284)
Total comprehensive income	$ 128,935	$ 120,686	$ 128,561

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

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NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2008	2007 (In thousands)	2006
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	$ 132,202	$ 124,105	$ 129,845
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	61,464	61,115	59,325
Allowance for equity funds used during construction	(323)	(30)	(192)
Changes in components of working capital	(4,062)	1,457	1,827
Gain on sale of assets	(16,166)		
Other	(3,705)	(2,146)	(5,479)
Total adjustments	37,208	60,396	55,481
Net cash provided by operating activities	169,410	184,501	185,326
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	(20,538)	(10,636)	(20,857)
Investments in other assets	(3,834)		
Proceeds from sale of assets	20,000		
Net cash used in investing activities	(4,372)	(10,636)	(20,857)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners		15,000	10,330
Distributions to partners	(181,320)	(172,668)	(178,841)
Issuance of debt	145,000	269,000	105,000
Retirement of debt	(130,000)	(273,000)	(112,000)
Debt financing costs		(257)	
Net cash used in financing activities	(166,320)	(161,925)	(175,511)
Net change in cash and cash equivalents	(1,282)	11,940	(11,042)
Cash and cash equivalents at beginning of year	22,937	10,997	22,039
Cash and cash equivalents at end of year	$ 21,655	$ 22,937	$ 10,997
Supplemental disclosures for cash flow information:			
Cash paid for interest, net of amount capitalized	$ 41,868	$ 44,481	$ 45,170
Changes in components of working capital:			
Accounts receivable	$ (1,474)	$ (1,234)	$ 8,179
Related party receivables	2,368	(2,399)	1,939
Materials and supplies	(357)	(235)	(404)
Prepaid expenses and other	85	(388)	422
Accounts payable	(1,084)	2,602	(5,973)
Related party payables	(2,000)	3,313	(1,016)
Accrued taxes other than income	(1,345)	54	(66)
Accrued interest	(223)	(232)	(10)
Other current liabilities	(32)	(24)	(1,244)
Total	$ (4,062)	$ 1,457	$ 1,827

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

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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, 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
Net income to partners	66,101	66,101		132,202
Changes associated with hedging transactions			(3,267)	(3,267)
Distributions paid	(90,660)	(90,660)		(181,320)
Partners equity at December 31, 2008	$ 395,688	$ 395,688	$ (5,708)	$ 785,668

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

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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.

The ownership and voting percentages of our partners at December 31, 2008 and 2007 are as follows:

Partner	Ownership
ONEOK Partners Intermediate Limited Partnership (ONEOK Partners)	50%
TC PipeLines Intermediate Limited Partnership (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.

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, 2008 and 2007, we have reflected regulatory assets of approximately $21.7 million and $20.6 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, 2008 and 2007.

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	December 31,			
	2008		2007	
	(In thousands)			
Fort Peck lease option	$	12,052	$	10,797
Pipeline extension project		5,998		6,459
Unamortized loss on reacquired debt		176		308
Deferred rate case expenditures		1,566		1,953
Compressor usage surcharge tracker		1,886		1,121
Total regulatory assets	$	21,678	$	20,638

At December 31, 2008 and 2007, respectively, we have reflected a regulatory liability of $4.7 million and $2.4 million on the balance sheets, 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. 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. 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. At December 31, 2008, we have reflected an allowance for doubtful accounts of approximately $0.6 million on the balance sheets. We did not have an allowance for doubtful accounts at December 31, 2007. 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.

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.

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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 (see Note 3), the effective depreciation rate applied to our transmission plant in 2008 and 2007 is 2.40 percent. The effective depreciation rate applied to our transmission plant in 2006 was 2.25 percent. The transmission plant depreciation rate 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, 2008 and 2007, $4.7 million and $2.4 million, respectively, is included as a regulatory liability on the accompanying balance sheets for accrued negative salvage. Composite rates are applied to all other functional groups of property having similar economic characteristics.

We apply the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations, which 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. 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.

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 sheets as either an asset or liability measured at their fair value (see Note 7). 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 6).

In March 2008, the Financial Accounting Standards Board (the FASB) issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities-an amendment to FASB Statement No. 133 , which requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS No. 161 is effective for our fiscal year beginning January 1, 2009 and will be applied prospectively.

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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.

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.

3. 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.

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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 sheets. 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 sheets. As of December 31, 2008 and 2007, we had recorded $1.9 million and $1.1 million, respectively, as a regulatory asset on the accompanying balance sheets for the net under recovery of compressor usage related costs.

In February 2008, we filed an application for the Des Plaines Project with the FERC to construct own and operate interconnect facilities including a 1,600 horsepower compressor facility near Joliet, Illinois. The Des Plaines Project is estimated to cost approximately $18 million and will be financed with a combination of debt and equity. A certificate order issued by the FERC authorizing the construction of the Des Plaines Project was received in July 2008 and construction commenced in September. It is anticipated the facilities will be placed in service by early 2009.

4. MAJOR CUSTOMERS

For the year ended December 31, 2008, shippers providing significant operating revenues were BP Canada Energy Marketing Corp. (BP Canada) and Cargill Inc. (Cargill) with revenues of $38.8 million and $32.4 million, 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.

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5. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

	December 31, 2008	December 31, 2007
	(In thousands)	
2007 Credit Agreement - average interest rate of 3.36% and 5.35% at December 31, 2008 and 2007, respectively, due 2012	$ 181,000	$ 166,000
1999 Senior Notes 7.75%, due 2009	200,000	200,000
2001 Senior Notes 7.50%, due 2021	250,000	250,000
Unamortized debt discount	(565)	(714)
Subtotal	630,435	615,286
Current maturities	(200,000)	
Long-term debt	$ 430,435	$ 615,286

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 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, 2008, based on the principal commitment amount of $250 million, available capacity under the 2007 Credit Agreement was $69 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 an applicable margin 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 leverage ratio (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 specified material acquisitions are consummated, the permitted leverage ratio 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, 2008, 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 $181 million in 2012. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2010, 2011 or 2013.

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, 2008 and 2007, was approximately $447 million and $493 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.

6. 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 (loss) and amortized to interest expense over the term of the debt.

During the years ended December 31, 2008, 2007, and 2006, respectively, we amortized approximately $1.5 million, $1.6 million, and $1.3 million related to the terminated interest rate swap agreements as a reduction to interest expense from accumulated other comprehensive income (loss). We expect to amortize approximately $1.0 million as a reduction to interest expense in 2009.

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 and 2006, we amortized approximately $0.7 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, 2008, the balance sheet reflected an unrealized loss of approximately $3.6 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 hedge ineffectiveness of the Collar Agreement.

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7. FAIR VALUE MEASUREMENTS

We adopted the provision of SFAS No. 157, Fair Value Measurements on January 1, 2008. Pursuant to SFAS No. 157, fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. We have determined that our liabilities are level 2 inputs. Level 2 inputs are significant observable pricing inputs other than quoted prices in active markets that are either directly or indirectly observable as of the reporting date. Essentially, inputs that are derived principally from or corroborated by observable market data. When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management s best estimate is used.

The following table sets forth the fair value measurement of our liabilities that are subject to SFAS No. 157 as of December 31, 2008.

	Fair Value Measurements Using		
	Quoted Price in Active Market (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		(In thousands)	
Derivative Instrument Liabilities - Hedges	$	$ 3,633	$
Total	$	$ 3,633	$

8. COMMITMENTS AND CONTINGENCIES

Operating Leases

We make lease payments under non-cancelable operating leases on office space and rights-of-way. Expenses incurred related to these lease obligations for the years ended December 31, 2008, 2007 and 2006 were $2.5 million, $1.5 million, and $0.7 million, respectively. Our future minimum lease payments, which assume we exercise the option to renew a pipeline right-of-way lease in April 2011 for a term of 25 years (discussed below), are as follows:

	(In thousands)
Year ending December 31,	
2009	$ 2,541
2010	2,193
2011	1,889
2012	1,889
2013	1,889
Thereafter	59,182
	$ 69,583

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.

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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 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 sheets. Future remaining payments for this obligation are as follows:

		(In thousands)
Year ending December 31,		
2009	$	753
2010		753
2011		753
	$	2,259

Environmental Matters

We are not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations (see Note 12).

Other

As of December 31, 2008, we have made commitments of $2.2 million in connection with construction of the Des Plaines Project.

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 April 2006, ONEOK Partners completed the sale of a 20 percent partnership interest in us to TC PipeLines. Upon the closing of the sale, 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, 2008, 2007 and 2006, we paid distributions to our general partners of $181.3 million, $172.7 million and $178.8 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.

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10. OTHER INCOME (EXPENSE)

Other income (expense) on the statements of income includes investment income, nonoperating revenues and expenses, and other income and expense items. For the years ended December 31, 2008, 2007 and 2006, other income (expense) included:

	Years Ended December 31, 2008		2007 (In thousands)		2006	
Other income						
Nonoperating revenue	$	1,638	$	1,638	$	1,086
Investment income		238		691		627
Other		1,056		98		505
Other income	$	2,932	$	2,427	$	2,218
Other expense						
Depreciation and amortization for non-regulated property	$	(382)	$	(382)	$	(604)
Other		(44)		(106)		(18)
Other expense	$	(426)	$	(488)	$	(622)

11. RELATED PARTY TRANSACTIONS

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 years ended December 31, 2008 and 2007, our charges from TransCanada and its affiliates totaled approximately $28.6 million and $22.5 million, respectively.

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 and 2006, our charges from ONEOK Partners GP and its current and former affiliates totaled approximately $9.3 million and $26.2 million, respectively. Our 2007 charges include $3.6 million for transition related costs. See Note 8 for discussion of transition related costs.

For the years ended December 31, 2008, 2007 and 2006, we had contracted firm capacity held by one shipper affiliated with one of our general partners. Revenue from ONEOK Energy Services Company, LP (ONEOK Energy), a subsidiary of ONEOK, for 2008, 2007 and 2006 was $5.0 million, $5.1 million and $7.0 million, respectively. At December 31, 2008 and 2007, we had outstanding receivables from ONEOK Energy of $0.4 million and $0.8 million, respectively.

In March 2008, we formed a wholly-owned subsidiary, Bison Pipeline LLC (Bison) to develop the Bison Project. The Bison Project is a proposed pipeline system that would extend from natural gas gathering facilities located in the Powder River Basin in Wyoming to a point of interconnection with our pipeline system in Morton County, North Dakota.

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In August 2008, we sold Bison to TransCanada Pipeline USA Ltd., a wholly-owned subsidiary of TransCanada, for $20.0 million. In connection with this transaction, we recorded a gain on sale of $16.2 million. Through the effective date of the sale, Bison received services from TransCanada and its affiliates totaling approximately $2.0 million in 2008.

In June 2008, in connection with the Des Plaines Project, we and ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada, have entered into an interconnect agreement, which provides that we will reimburse ANR for the cost of certain of the interconnect facilities to be owned by ANR. In 2008, we paid ANR $0.5 million and it is estimated that additional costs to complete the interconnect facilities will be $0.1 million. We will be responsible for the final costs to construct the interconnect facilities and any difference between the final actual costs and the estimated amounts paid will be remitted by or refunded to us.

12. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $48.4 million was declared and paid on February 2, 2009 for the fourth quarter of 2008.

We received a Notice of Violation (NOV) from the United States Environmental Protection Agency (EPA) dated February 2, 2009 alleging that we were in violation of certain regulations pursuant to the Clean Air Act regarding a compressor station on our system. As provided by the NOV, we have requested a conference with the EPA to discuss the violations alleged in the NOV. At this time, we are unable to reasonably estimate the cost of any associated corrective action or the possibility or amount of any penalty, but do not expect such amounts to be material to our financial condition.