2010 Annual Report

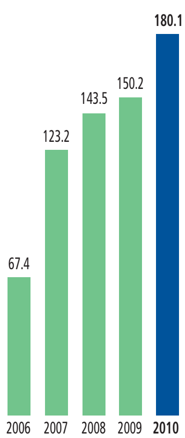
Delivering Value
Disciplined Investment

TC PipeLines, LP

Financial Highlights

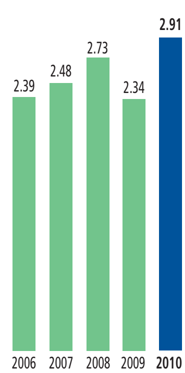
Year ended December 31 (millions of dollars, except per unit amounts)	2006	2007	2008	2009	**2010**
Cash Flow					
Partnership cash flows*	67.4	123.2	143.5	150.2	**180.1**
Cash distributions paid	43.5	86.7	108.6	117.0	**138.7**
Income Statement					
Net income**	49.1	94.7	123.0	106.1	**137.1**
Net income prior to recast*	44.7	89.0	107.7	97.8	**137.1**
Balance Sheet					
Total assets**	1,008.1	1,732.4	1,701.1	1,675.1	**1,650.5**
Long-term debt (including current maturities)	468.1	573.4	536.8	541.3	**513.9**
Partners' equity	303.9	900.1	875.6	1,103.5	**1,112.5**
Common Units Statistics (per unit)					
Cash distributions paid	$ 2.325	$ 2.565	$ 2.775	$ 2.870	**$2.940**
Net income	$ 2.39	$ 2.48	$ 2.73	$ 2.34	**$2.91**
Common Units Outstanding (millions)					
Weighted average for the year	17.5	32.3	34.9	38.7	**46.2**
End of year	17.5	34.9	34.9	46.2	**46.2**

Partnership Cash Flows* (millions of dollars)

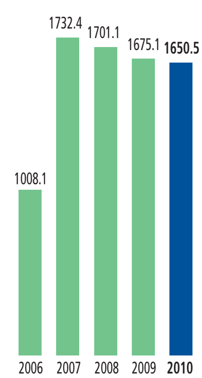


Cash Distributions Paid (dollars per unit)

Net Income (dollars per unit)



Total Assets (millions of dollars)



*Partnership cash flows and net income prior to recast are non-GAAP measures. Non-GAAP measures do not have any standarized meaning prescribed by generally accepted accounting principles (GAAP). For more information on non-GAAP financial measures see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K for the year ended December 31, 2010, filed with the SEC and included in this annual report.

**Recast as discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K for the year ended December 31, 2010, filed with the SEC and included in this annual report.

This annual report contains forward-looking statements relating to expectations, plans or prospects for TC PipeLines, LP. These statements are based upon the current expectations and beliefs of management and are subject to certain risks and uncertainties that could cause actual results to differ materially from those described in the forward-looking statements. These risks and uncertainties include market conditions and other factors beyond the company's control. Please read the cautionary statements found on page 7, and the risk factors found on page 19, which discuss these factors.

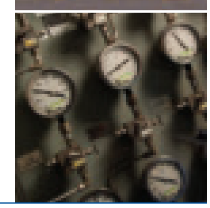
TC PipeLines, LP is a United States limited partnership with a **long history of stable and growing cash distributions** which has ***delivered value*** to its investors while maintaining a solid cash distribution coverage ratio.

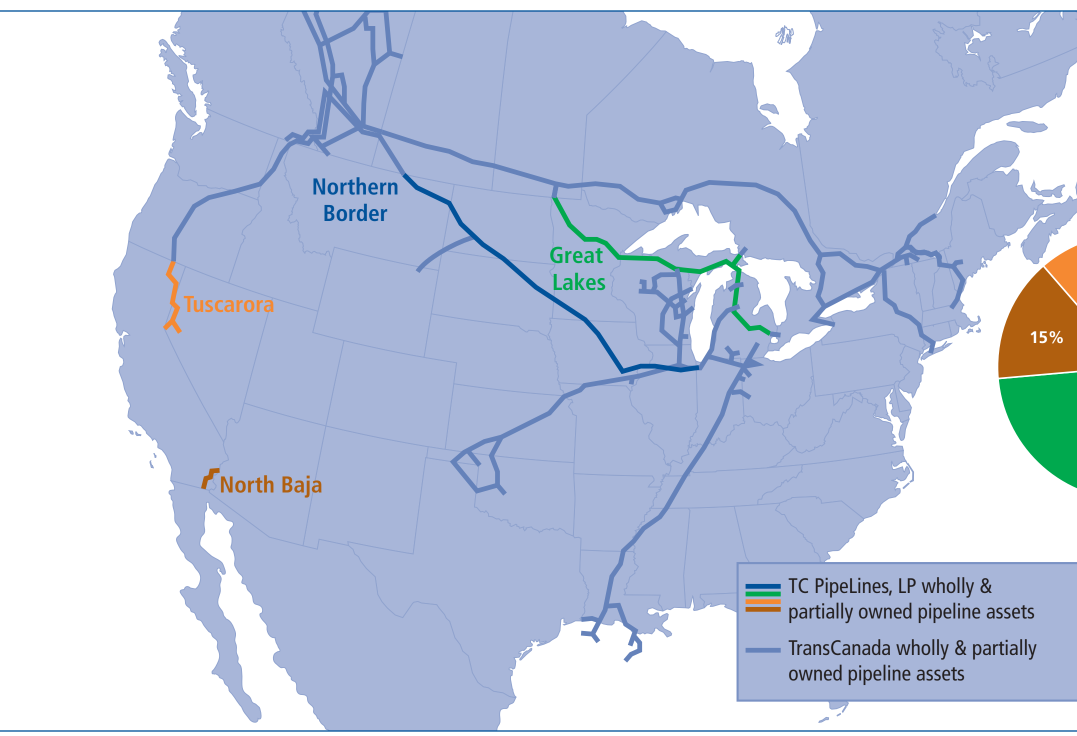
Through its disciplined investment philosophy, TC PipeLines has investments in four critical FERC regulated, low-risk energy infrastructure pipelines, capable of moving 5.6 billion cubic feet per day of natural gas. Revenues from these assets are derived almost entirely from fee-based charges.

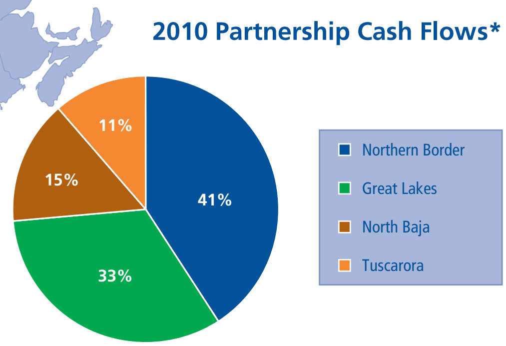
With access to new gas supplies through support from its sponsor, TransCanada, who also operates our assets on our behalf, TC PipeLines' assets are primarily connected to one of the largest supply basins in North America that is positioned to recover and grow over the next decade.

With a strong and conservative balance sheet, a low general partner cash take and an ample amount of available liquidity, we are well positioned for growth.

Growth sources have the potential to come from multiple sources: drop-down opportunities from our sponsor who is half-way through their C$20 billion capital program, through third party acquisitions and organic expansion projects on our existing pipelines, all of which could ultimately support TC PipeLines' ability to provide growing and sustainable cash flows to its investors.







* Percentages represent the proportion of Partnership Cash Flows derived from distributions received from Great Lakes and Northern Border, and operating cash flows from North Baja and Tuscarora, before deducting Partnership costs. Refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — How We Evaluate Our Operations — Partnership Cash Flows" for additional information on Partnership Cash Flows.

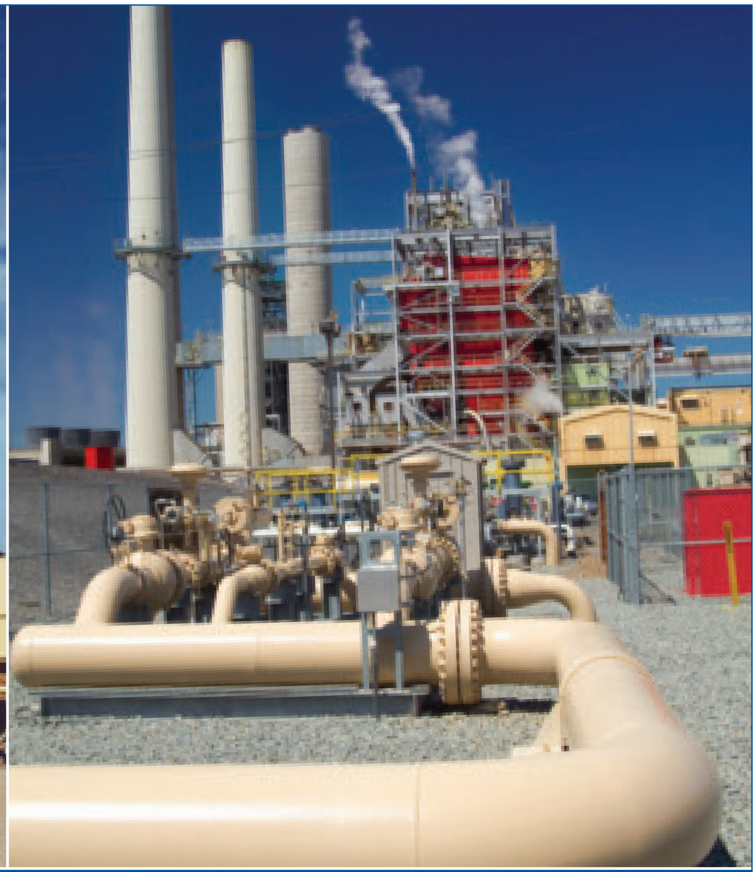
Mid-Western Interstate Pipeline Assets

Northern Border (50% Ownership Interest)

- 1,398 miles of pipeline serving markets in Minneapolis (via Ventura connection), Chicago, and other mid-west markets
- Design capacity of 2,374 million cubic feet per day
- Key interconnections into 8 regional pipelines
- Moving additional U.S. Rockies gas supply via the Bison Pipeline, wholly owned by TransCanada Corporation, as of January 2011
- Percentage of revenues from Capacity Reservation Charges: 89%
- Substantially contracted through March 2012

Great Lakes (46.45% Ownership Interest)

- 2,115 miles of pipeline serving markets in Minnesota, Wisconsin, Michigan and eastern Canada
- Design capacity of 2,300 (summer)/ 2,500 (winter) million cubic feet per day
- Strong interconnections with gas storage with a total regional storage capacity of 650 billion cubic feet
- Percentage of revenues from Capacity Reservation Charges: 95%
- Contracted through October 2011



California Regional Pipeline Assets

North Baja (100% Ownership)

- 86 mile bi-directional pipeline system serving growing demand from primarily natural gas power generation in Baja, Mexico and Southern California
- Design capacity of 600 (northbound) million cubic feet per day and 500 (southbound) million cubic feet per day
- Interconnects with U.S. supply and LNG-sourced natural gas
- Percentage of revenues from Capacity Reservation Charges: 100%
- Long term contracts that range between 2022 and 2028

Tuscarora (100% Ownership)

- 305 miles of pipeline serving markets in Northern California and northwestern Nevada
- Design capacity of 230 million cubic feet per day
- Percentage of revenues from Capacity Reservation Charges: 99%
- Contracted through 2016

Letter to Unitholders

2010 marked a very successful year for TC PipeLines. Our strategy has been to invest in low risk, fee-based assets supported by strong fundamentals. These types of assets provide earnings and cash flow certainty due to their regulated nature. This strategy has served us well. Over the past ten years, we've outperformed the Alerian MLP Total Return Index. An original investment back in 2001 provided you, our unitholder, a total return of 475 per cent which was 40 per cent higher than the index. This impressive track record of delivering value stems from our long history of providing stable and growing distributions in a conservative and disciplined manner.

Year in Review

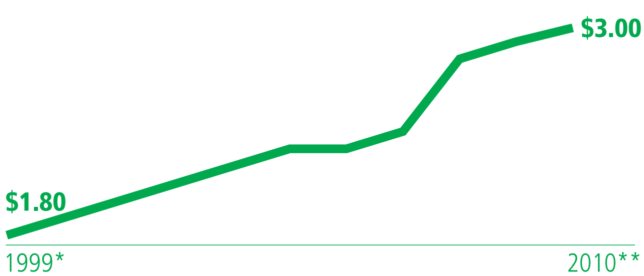
The North American economy is starting to show signs of a sustained recovery and appears to be slowly improving. Within this environment, TC PipeLines had a very successful year attributed to the strong financial results from all four of our pipeline assets, in particular, Northern Border. Several key events and accomplishments contributed to this success:

1. Increased cash distributions paid on a per unit basis by 2.4 per cent
2. Reached a negotiated settlement on the Great Lakes Section 5 rate proceeding
3. Placed North Baja's Yuma lateral into service on March 13, 2010
4. Received Federal Energy Regulatory Commission (FERC) approval on November 22, 2010 for construction of the $18 million Northern Border Princeton lateral
5. In January 2011, Northern Border started moving U.S. Rockies gas via the interconnection with TransCanada's Bison pipeline.

As we move forward into 2011, we look to build on our successes in 2010 as we continue to execute our business strategy.

Stable Cash Flows and Growing Distributions

Our Partnership experienced a strong year in terms of financial performance. Partnership cash flows increased $30 million to $180 million. Cash distributions paid to unitholders increased $22 million to $139 million. Despite the increase in distributions paid to unitholders, we continue to maintain a solid distribution coverage ratio ending with 1.30 times coverage.

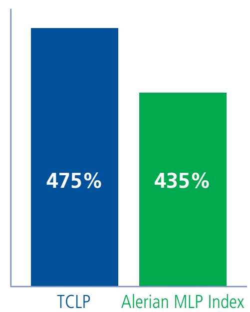


67% Growth in Annual Cash Distributions Paid per Common Unit Since Inception.

*Prorated for full year
**Fourth quarter distribution on an annualized basis

For the year, Partnership net income increased $31 million to $137 million, or $2.91 per common unit. This increase of 29 per cent came primarily from the strong performance of Northern Border.

10 Year Total Return



Essential Infrastructure

With interests in over 3,900 miles of interstate natural gas pipelines and a combined total deliverable capacity of 5.6 billion cubic feet per day (bcf/d), our assets are essential infrastructure that supply approximately five per cent of the United States daily gas volumes and are well interconnected to the key markets that they serve. During the course of year, our assets performed exceptionally well, demonstrating the strong fundamentals that support our business.

On July 15, 2010, the FERC approved our settlement resulting from the Great Lakes Section 5 rate proceeding. Under the terms of the settlement, maximum reservation rates on Great Lakes were reduced by eight per cent. This rate reduction should help ensure that Great Lakes' remains competitive as a key pipeline serving midwest markets. Our team did an outstanding job working with the FERC and our shippers on a settlement which provides us with greater certainty on future tolls.

Northern Border's strong year can be attributed to the increased demand for its transportation services as the temporary gas oversupply situation faced in 2009 corrected itself in 2010. As reduced supplies from other pipelines which now are serving other markets, volumes rebounded in 2010 as it experienced strong demand for its services and favorable basis differentials. In addition, Northern Border received approval to construct the $18 million Princeton lateral which is supported by a 10 year firm-service contract that will connect to a power generation facility.

Both North Baja and Tuscarora are situated in unique geographic locations and the profile of their long term contracts provide stable earnings and cash flows from year to year. As such, these two pipelines are generally unaffected by shifting natural gas supply and demand fundamentals and provide good diversification to our portfolio of pipeline assets. North Baja expanded its reach as it placed the Yuma lateral in south west Arizona into service in March 2010 to serve an expansion of a power generation facility which is expected online in early 2011.

In a year that saw two major tragic pipeline incidents, operator safety and maintenance practices have been called into question. TC PipeLines is proud to be supported by a strong sponsor in TransCanada. As our general partner and the operator of our assets, TransCanada operates North America's largest natural gas pipeline network and is proud of its operating history and maintenance practices. While it is too early to tell what the potential impact of the various proposed industry regulations, we will continue to monitor the situation closely. We remain confident our pipeline assets are essential North American infrastructure for the markets that they serve and will continue to represent solid investments for TC PipeLines.

Accessing New Gas Supply

Strong support from our sponsor, TransCanada, is one of our core strengths. TransCanada is in the midst of developing its large multi-year capital program. As part of this program, several developments are expected to have a positive impact on TC PipeLines.

Construction began on the Bison natural gas pipeline in July 2010 and became operational in January 2011. The Bison pipeline will bring gas from the Powder River Basin in Wyoming and interconnect with the Northern Border pipeline in North Dakota. Bison shippers have executed 10 year downstream contracts on Northern Border for 407 million cubic feet per day (mmcf/d) from the Port of Morgan, Montana, to Ventura, Iowa. These contracts will not only strengthen Northern Border's contract portfolio, but also help to diversify its natural gas supply. The pipeline also has the potential for expansion through additional compression.

In November 2010, TransCanada began moving gas from the Montney shale gas formation in northeastern British Columbia on its newly constructed Groundbirch pipeline into the Alberta System. The project has firm transportation contracts that will reach 1.24 bcf/d by 2014. TransCanada's other shale gas pipeline project will connect Horn River gas. The Horn River pipeline has contract commitments that will reach 634 mmcf/d by 2014 and is expected to be operational in the second quarter 2012. These two projects will bring approximately 1.9 bcf/d of new shale gas volumes onto TransCanada's Alberta System that will be ultimately be available for consumption and export to downstream markets.

In addition to the committed volumes received to date, TransCanada also has received expressions of interest from producers for an additional 2.3 bcf/d of transportation services from these developing shale plays. The continued interest from natural gas producers to develop shale gas plays within the Western Canadian Sedimentary Basin (WCSB) leads us to remain optimistic that volumes produced and exported out of the WCSB will stabilize in the near term and will start to increase over time as the potential of the Horn River and Montney shale plays are developed and brought on stream. Both Northern Border and Great Lakes are well positioned to play an integral role in this regard as producers require major reliable pipelines to move this gas to market.

Looking beyond the growth in Canadian shale gas plays, our long haul pipelines are uniquely positioned to capture volumes from other U.S. shale gas sources. The emerging Bakken shale play in Montana and North Dakota along with the Collingwood shale play in Michigan are future sources of gas supply that Northern Border and Great Lakes could potentially capture and move to market given their footprint.

Positioned for Growth

Our conservative and strong balance sheet which includes a largely undrawn credit facility and a low general partner cash take that is amongst the lowest in the industry, provides us with the financial flexibility and liquidity to pursue growth opportunities in a disciplined manner that will benefit our unitholders over the long term.

Growth opportunities have the potential to come from several sources. With TransCanada now close to half way through its C$20 billion multi-year capital program, TC PipeLines could potentially play a key role in its financing needs to complete this program. While we wait for an opportunity to assist TransCanada with its capital needs, we continue to explore opportunities to acquire third party assets that would complement our existing asset base. As we evaluate these opportunities, rest assured that we will remain disciplined in our investment approach, only selecting those that provide the ability to grow earnings, cash flows and distributions in a stable low-risk manner.

With access to a large pool of talent for management through our affiliation with TransCanada, the strong fundamentals supporting our existing asset base, a promising long-term outlook for gas with the growth in gas supplies from new shale plays and with a sound financial position, I am confident the Partnership is well positioned to continue delivering value to its unitholders and will provide stable and growing cash distributions well into the future.

On behalf of TC PipeLines, LP

Steve Becker

Steve Becker
President, TC PipeLines, LP

TC PIPELINES, LP

TABLE OF CONTENTS

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

PART I

FORWARD-LOOKING STATEMENTS

The statements in this report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (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;
- the competitive conditions in our industry and the ability of Great Lakes, Northern Border, North Baja Pipeline, LLC (North Baja) and Tuscarora Gas Transmission Company (Tuscarora, and together with Great Lakes, Northern Border and North Baja, "our pipeline systems") to market pipeline capacity on favorable terms, which is affected by, among other factors:
  - 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 and relative cost of supplies of Canadian and United States (U.S.) natural gas, including the discovered shale gas resources such as the Horn River and Montney deposits in Western Canada and the Bakken formation in the Midwestern U.S., along with U.S. Rockies, Mid-Continent and Marcellus natural gas developments;
  - competitive developments by U.S. and Canadian natural gas transmission companies;
  - the availability of additional storage capacity and current storage levels;
  - the level of liquified natural gas imports;
  - weather conditions that impact supply and demand; and
  - the ability of shippers to meet creditworthiness requirements;
- the impact of current and future laws, rulings and governmental regulations, particularly Federal Energy Regulatory Commission (FERC) regulations and rate proceedings, and proposed and pending legislation by Congress and proposed and pending regulations by the U.S. Environmental Protection Agency (EPA) and other regulators in the U.S. on us and our pipeline systems;
- the 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);
- decisions by other pipeline companies to advance projects that will affect our pipeline systems;
- the regulatory, financing and construction risks related to construction of interstate natural gas pipelines and additional facilities;
- our ability and that of our pipeline systems to identify and/or consummate expansion projects and other accretive growth opportunities;
- the performance of contractual obligations by customers of our pipeline systems;

- the imposition of entity level taxation by states on partnerships;
- the operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- our ability to control operating costs, including the operations of our pipeline systems; and
- the general economic conditions in North America, which impact:
  - the debt and equity capital markets and our ability to access these markets at reasonable costs;
  - the overall demand for natural gas by end users; and
  - natural gas prices.

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 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

Limited Partnership

TC PipeLines, LP is a publicly traded Delaware limited partnership formed in 1998 to acquire, own and participate in the management of energy infrastructure businesses in North America. Our common units are listed on the NASDAQ Global Select Market under the symbol "TCLP." TC PipeLines, LP's General Partner is TC PipeLines GP, Inc., which is wholly-owned by a subsidiary of TransCanada Corporation.

TC PipeLines, LP and its subsidiaries are collectively referred to herein as "the Partnership." In this report, references to "we," "us" or "our" refer to the Partnership. TransCanada Corporation, together with its subsidiaries, is referred to as TransCanada.

The Partnership has ownership interests in four natural gas interstate pipeline systems that collectively can transport approximately 5.6 billion cubic feet per day (Bcf/d) of natural gas, including partial ownership in Northern Border Pipeline Company (Northern Border) and Great Lakes Gas Transmission Limited Partnership (Great Lakes), which primarily ship Western Canadian natural gas to markets in the Midwestern U.S. and Eastern Canada, and full ownership in North Baja Pipeline, LLC (North Baja) and Tuscarora Gas Transmission Company (Tuscarora), which transport natural gas to markets in California and the U.S. Southwest. Distributions from Northern Border and Great Lakes provide the largest portion of distributable cash flow available to the Partnership. Each of these pipelines is operated under agreements with subsidiaries of TransCanada. See Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information on our relationship with TransCanada.

Specifically, through our subsidiaries, we own:

- 46.45 percent of Great Lakes, a Delaware limited partnership formed in 1990. The remaining 53.55 percent is held by subsidiaries of TransCanada.

  The Great Lakes pipeline system consists of 2,115 miles of pipeline extending from the Canadian border near Emerson, Manitoba, Canada to St. Clair, Michigan, near Detroit, and has an average design capacity of approximately 2.4 Bcf/d at Emerson. The original construction of the Great Lakes system occurred in 1967 and 1968. Numerous capacity system expansions have occurred since its original construction, the last one completed in 1998.

- 50 percent of Northern Border, a Texas general partnership formed in 1978. The remaining 50 percent is held by ONEOK Partners, L.P. (ONEOK Partners).

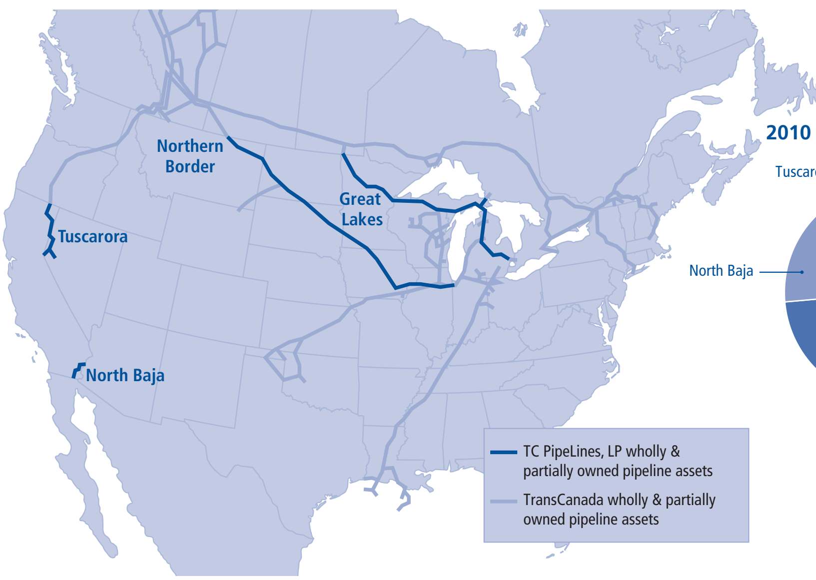
  The Northern Border pipeline system consists of 1,398 miles of pipeline extending from the Canadian border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana, south of Chicago. Northern Border has a design capacity of approximately 2.4 Bcf/d. Construction of Northern Border's system was initially completed in 1982, followed by expansions or extensions in 1991, 1992, 1998, 2001 and 2006.

- 100 percent of North Baja, a Delaware limited liability company formed in 2000.

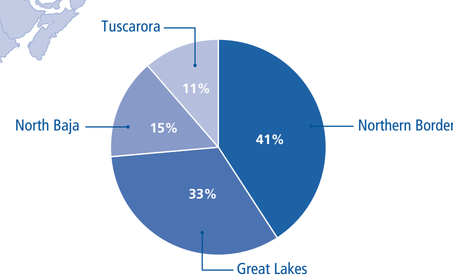
  The North Baja pipeline system consists of 86 miles of pipeline extending from an interconnection with the El Paso Natural Gas Company (EPNG) pipeline near Ehrenberg, Arizona, to an interconnection with the Gasoducto Bajanorte natural gas pipeline near Ogilby, California on the Mexican border. North Baja has a design capacity of 500 million cubic feet per day (MMcf/d) for southbound transportation and 600 MMcf/d for northbound transportation. The North Baja pipeline system was initially placed into service in 2002. An expansion was completed in April 2008 to allow for bi-directional natural gas flow and the Yuma Lateral, from the Mexico/Arizona border to Yuma, Arizona, was completed in March 2010.

- 100 percent of Tuscarora, a Nevada general partnership formed in 1993.

  The Tuscarora pipeline system consists of 305 miles of pipeline extending from the Gas Transmission Northwest Corporation (GTN) pipeline, a wholly-owned subsidiary of TransCanada, near Malin, Oregon to a terminus near Wadsworth, Nevada. Tuscarora has a design capacity of 230 MMcf/d. The Tuscarora pipeline system was initially placed into service in 1995, followed by expansions or extensions in 2001, 2002, 2005 and 2008.



2010 Partnership Cash Flows*



* Percentages represent the proportion of Partnership Cash Flows derived from distributions received from Great Lakes and Northern Border, and operating cash flows from North Baja and Tuscarora, before deducting Partnership costs. Refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations – Partnership Cash Flows" for additional information on Partnership Cash Flows.

Business Strategies

- Our strategic approach is to invest in long-term, critical energy infrastructure that provides reliable delivery of energy to customers in the United States.
- Our investment approach is to develop or acquire assets that provide stable cash distributions and opportunities for new capital additions, while maintaining a low-risk profile. We are opportunistic and disciplined in our approach when identifying new investments.
- Our operational approach is to maximize the utilization of our pipeline systems, with a commitment to safe and reliable operations.

Relationship with TransCanada

One of our principal strengths is our relationship with TransCanada. TransCanada is a major energy infrastructure company, listed on the Toronto Stock Exchange and New York Stock Exchange, with more than 50 years of experience in the responsible development and reliable operation of energy infrastructure in North America. TransCanada is primarily focused on natural gas and oil transmission and power generation services. Together with assets under construction, TransCanada owns more than $46.6 billion in total assets, including 37,000 miles of wholly-owned natural gas pipelines, interests in an additional 5,500 miles of natural gas pipelines, 2,150 miles of wholly-owned oil pipelines and approximately 380 billion cubic feet (Bcf) of storage capacity. TransCanada also owns, controls or is developing over 10,800 megawatts of power generation.

TransCanada, through its subsidiaries, currently owns a 38.2 percent interest in the Partnership and our pipeline systems, including an effective two percent general partner interest and a 12.3 percent limited partner interest held by TC PipeLines GP, Inc., our General Partner. Subsidiaries of TransCanada operate our pipeline systems and one subsidiary, TransCanada PipeLines Limited, is the largest customer on Great Lakes. We expect 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. 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 Part II, 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.

Interstate Natural Gas Pipeline Business

Supply

Our pipelines are a critical part of the natural gas market in the U.S. and transport natural gas from producing regions and import facilities to market hubs and consuming markets.

Natural gas is transported from producing regions and liquified natural gas (LNG) import facilities to market hubs for distribution to natural gas consumers. The main producing regions in North America are the Gulf of Mexico, Western Canada Sedimentary Basin (WCSB), Mid-Continent, Rockies, Permian basin and San Juan basin. Northeastern U.S., the Midwest and the West Coast are three large natural gas regions in the U.S. Recent increases in the development of unconventional and shale gas have resulted in increases in overall North American natural gas production and increased reserves. Over the past few years, significant new pipeline infrastructure has been added to move natural gas from producing regions to market areas. This impacts the transportation value on pipelines, including our pipeline systems. Additional pipeline projects have been proposed, including projects to move additional natural gas supply into western market regions, which are expected to continue to impact overall North American natural gas flows. Additionally, development of new producing regions, such as the Marcellus shale in the eastern U.S., the Montney and Horn River shale areas in northeastern British Columbia, Canada and the Bakken shale area in North Dakota and Montana, will also impact North American natural gas flows. In the longer term, reserves from northern natural gas also have the potential to increase supply coming out of the WCSB.

Great Lakes primarily transports natural gas produced in the WCSB and receives it at an interconnection with the TransCanada Mainline pipeline system (TransCanada Mainline) at the Canadian border near Emerson, Manitoba, Canada. Great Lakes extends across Minnesota, Northern Wisconsin and Michigan and redelivers natural gas to TransCanada at the Canadian border near Sault Ste. Marie, Ontario, Canada and St. Clair, Michigan. Great Lakes also connects to storage centers in Michigan and, through the TransCanada Mainline, interconnects to the Dawn, Ontario market region (Dawn). Great Lakes also interconnects with other interstate natural gas pipelines, including TransCanada's ANR pipeline system (ANR), that primarily source natural gas from the Gulf of Mexico and Mid-Continent regions.

Northern Border primarily transports natural gas produced in the WCSB and receives it at an interconnection with one of TransCanada's pipelines at the Canadian border near Port of Morgan, 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 together accounted for approximately 10 percent of the natural gas Northern Border transported in 2010. In addition, synthetic natural gas produced at the Dakota Gasification plant in North Dakota accounted for approximately six percent of the natural gas transported by Northern Border in 2010. In January 2011, TransCanada completed the Bison pipeline, which extends from Wyoming to an interconnection with Northern Border in Morton County, North Dakota. The Bison pipeline provides additional natural gas sourced from the Powder River Basin to Northern Border.

North Baja receives natural gas from an interconnection with EPNG at Ehrenberg, Arizona that sources natural gas primarily from the West Texas and Southern Rocky Mountain supply regions. Due to the bi-directional capability modifications completed in April 2008, North Baja is also able to transport natural gas northbound at Ogilby, California, and receives natural gas sourced from the Energia Costa Azul (Costa Azul) LNG terminal in Mexico.

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. Ruby Pipeline, LLC (Ruby), which is currently under construction, will interconnect with GTN and Tuscarora. Ruby is projected to be in service in mid-2011 and, once completed, is expected to increase Tuscarora's access to natural gas from the Rockies.

Demand and Seasonality

The demand for transportation service on a pipeline depends on a number of factors, including:

- demand for natural gas in the markets served;
- price of natural gas at the pipeline delivery point compared to other markets;
- availability of natural gas at the pipeline system's receipt points;
- transportation rates of competing pipelines;
- weather conditions; and
- availability and competitiveness of alternative supply sources and storage alternatives in the consuming market.

The impact on our revenues due to changes in demand for natural gas transportation services is primarily dependent upon the extent to which capacity has been contracted under long-term firm contracts. Tuscarora and North Baja have long-term firm contracts and do not experience revenue volatility due to seasonal changes in demand related to market conditions, including weather related demand. Great Lakes and Northern Border, however, are subject to annual contract renewals and can experience demand changes related to seasonal market conditions. Additionally, Northern Border's tariff has a seasonal rate structure providing for higher rates in the traditional peak months in the summer and winter seasons.

To the extent Great Lakes' capacity is contracted, utilization does not impact revenues significantly. In periods when Great Lakes is not fully contracted, its revenues are affected by demand for its long-haul transportation service that is normally at its highest when natural gas is being delivered to storage areas. The high demand period usually begins in the spring and extends through most of the summer. During the winter, there is also strong demand for Great Lakes' services to meet the peak winter heating demand requirements of Minnesota, northern Wisconsin and Michigan.

Northern Border's revenues are partially affected by demand for transportation services that has traditionally been the strongest during peak winter months to serve heating demand and peak spring/summer months to serve electric cooling demand and storage injection.

North Baja has substantial contracts for both southbound and northbound transportation service and these reservation-based contracts provide predictable revenues despite variability in the amount of natural gas or the direction that natural gas may flow. Similarly, Tuscarora's significant long-term contract profile ensures stable revenues that are not subject to utilization risk.

Competition

Competition among natural gas pipelines is based primarily on transportation rates and proximity to natural gas supply areas and consuming markets. Our pipeline systems compete with other pipelines that source natural gas from the same supply regions, primarily the WCSB, and those that source natural gas from different supply regions but deliver to the same markets as our pipelines. The WCSB, which covers over 540,000 square miles, contains one of the world's largest reserves of petroleum and natural gas and supplies approximately 15 percent of the demand for natural gas in North America. "Gas exiting the WCSB" is the term we use to represent the net of the supply of and demand for natural gas in the WCSB region. The West Coast and the Midwest market, particularly Chicago, are two large natural gas consuming markets in the U.S. The Midwest market is also a major storage location and market hub for further distribution to east, north and central U.S. markets.

Great Lakes and Northern Border both compete for natural gas transportation customers with pipelines that transport gas exiting the WCSB. The primary competition for Great Lakes is the route from Western Canada to Dawn on the TransCanada Mainline. Other routes from Western Canada to Ontario, Canada include the Foothills Pipeline to Northern Border to Vector Pipeline route, and the Alliance Pipeline to Vector Pipeline route. In addition, natural gas can be delivered to the markets served by Great Lakes by competing pipelines that have access to alternate sources of supply from the Rockies, Mid-Continent, Gulf Coast and Marcellus shale areas.

Northern Border's system competes for WCSB natural gas transportation customers with other pipelines that transport WCSB supply to markets in the West, Midwest and East in North America. The pipeline systems that represent Northern Border's primary competition in these markets include Alliance Pipeline, Great Lakes, GTN and other pipelines that interconnect with the TransCanada Mainline for WCSB supply. Northern Border also competes with other pipelines that serve the same market area sourcing natural gas from storage facilities and from other supply regions in the Rockies, Mid-Continent, Permian Basin and Gulf Coast. The pipeline systems that deliver natural gas from other supply regions into the same market that Northern Border serves include Northern Natural Gas Company into the Ventura, Iowa market area, and ANR, Midwestern Gas Transmission Company and Natural Gas Pipeline of America into the Chicago market.

North Baja's southbound deliveries compete with LNG deliveries from the Costa Azul terminal when supply is received at that terminal. Shippers retain contracts on North Baja to be able to deliver natural gas to several power plants in Baja California, Mexico at times when LNG-sourced natural gas from the Costa Azul terminal is unavailable. As well, North Baja provides a northbound path for LNG from the Costa Azul terminal to markets in the southwestern U.S.

Tuscarora competes for deliveries into the Northern Nevada natural gas market mainly with natural gas from the Rockies delivered by the Paiute Pipeline system.

Customers and Contracting

Our customers are generally large utilities, local distribution companies and major natural gas marketers and production companies. Our pipelines generate revenue by charging rates for transporting natural gas. Natural gas transportation service is provided pursuant to long-term and short-term contracts.

All of our pipeline systems are regulated by the FERC. Our pipeline systems' transportation contracts, and accordingly, their operating revenues, are derived from rates stated in our tariffs. Tariffs specify the maximum and minimum transportation rates that our pipeline systems may charge their customers. Rates can be discounted to address competition, if necessary. In addition, tariffs specify the general terms and conditions for pipeline transportation service. Tariffs are approved by the FERC, and in most cases, are 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 on a pipeline system that would allow it to recover its cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set, a 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. As a result, earnings and cash flows of each pipeline system depend on costs incurred; contracted capacity and transportation path; the volume of natural gas transported; and the ability of each system to sell capacity at acceptable rates.

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, levels of available pipeline capacity and customers' judgments concerning future market trends and volatility. If market conditions are not favorable at the time of renewal, transportation capacity may remain uncontracted. Capacity would be recontracted, if and when market conditions become more favorable.

Increased competition and excess transportation capacity within the North American natural gas industry have resulted in a trend towards shorter term contracting as customers assess and choose the transportation paths that optimize their business.

For the year ended December 31, 2010, TransCanada, through the TransCanada Mainline and ANR, accounted for 20 percent of the Partnership's proportionate share of our pipelines' operating revenues.

REGULATORY ENVIRONMENT

Government Regulation

The FERC initiates regulatory changes through orders intended to create a more competitive environment in the natural gas marketplace. Among the most important of these orders on our pipelines are:

Promotion of a More Efficient Capacity Release Market, Order 712 et seq. – In a 2008 Final Rule, the FERC permanently lifted the maximum rate cap on capacity releases of one year or less, but retained the cap for capacity sold by pipelines. The Interstate Natural Gas Association of America (INGAA), of which TransCanada is a member, sought rehearing and then appealed the Capacity Release Final Rule to the U.S. Court of Appeals – D.C. Circuit, contending that rate treatment for short-term capacity should be the same whether it is available for shippers or the pipeline. In August 2010, the DC Circuit court denied the appeal. Under market conditions to date, this rule has not had a significant effect on our ability to compete with capacity releases in the short-term market.

Compliance with Statutes, Orders, Rules and Regulations Docket No. PL10-4-000 – In March 2010, and further revised in September 2010, the FERC issued a "Policy Statement on Penalty Guidelines" adopting a penalty guideline approach modeled after the United States Sentencing Guidelines for the purpose of providing greater fairness, consistency and transparency to the FERC's civil penalty determinations. We are not aware of any compliance issues that would invoke application of the penalty guidelines.

Composition of Proxy Groups for Rates of Return Determinations – The FERC uses proxy groups of publicly traded companies with business models similar to the pipeline for which a rate determination is sought in order to determine an appropriate return on equity (ROE) for that pipeline. In a 2008 Policy Statement, the FERC expanded the criteria for proxy group companies, thereby permitting the inclusion of master limited partnerships (MLPs). The effect of the FERC's evolving policy and precedent with regard to proxy groups, and the availability of risk-appropriate companies and MLPs for inclusion in a proxy group at the time of a rate case, may impact the ROEs for any of our pipeline systems involved in a rate case.

Enacted Regulations

All of our pipeline systems are regulated under the Natural Gas Act of 1938 (NGA), 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;
- acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- standards of conduct for business relations with certain affiliates.

FERC Rate Proceedings

Great Lakes – As a result of extensive settlement negotiations, in July 2010, the FERC approved a stipulation and agreement (GL Settlement) without modification. As approved, the GL Settlement will apply to all current and future shippers on Great Lakes' system. For additional information regarding the Great Lakes rate case, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Regulatory Environment – FERC Rate Proceedings – Great Lakes Rate Proceeding."

Northern Border – Northern Border operates pursuant to maximum long-term mileage-based rates and seasonal short-term transportation rates approved by the FERC in a January 1, 2007 rate case settlement. A moratorium on the filing of future rate cases under NGA Sections 4 or 5 expired on January 1, 2010. Northern Border must file a rate case on or before December 31, 2012.

North Baja – North Baja continues to operate under the rates approved by the FERC in 2004 in connection with North Baja's initial construction and has no requirement to file a new rate proceeding.

Tuscarora – Tuscarora operates pursuant to maximum transportation rates approved by the FERC in a July 2006 rate case settlement. A moratorium on the filing of future rate cases under NGA Sections 4 or 5 expired on May 31, 2010. There is no requirement for Tuscarora to file a new rate case; however, all parties to the settlement have the ability to file a rate case at any time.

Environmental Matters

We 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 can impact business operations in many ways, such as imposing strict requirements relating to the handling, transportation, storage and disposal of wastes requiring remedial action to mitigate pollution conditions, or requiring the installation of pollution abatement or control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial requirements and/or the issuance of orders enjoining future operations. These laws include, but are not limited to:

- *Resource Conservation and Recovery Act (RCRA)* – The operations of our pipeline systems generate hazardous and non-hazardous solid wastes that are subject to RCRA and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and non-hazardous solid wastes.
- *Toxic Substances Control Act (TSCA)* – The TSCA authorizes the EPA to screen existing and new chemicals used in industry and identify potentially dangerous products or uses that should be subject to federal control.
- *Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)* – CERCLA, also known as "Superfund," and comparable state laws, regulate the cleanup of hazardous substances and impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons relating to the release of hazardous substances into the environment. We currently own or lease properties that for many years have been used for the transportation and compression of natural gas, which involves the use of hazardous substances and other regulated materials that may be subject to CERCLA and comparable state laws. Under such laws, we could be required to remove any previously released hazardous substances, remediate contaminated property or perform remedial closure operations to prevent future contamination, even if the disposal or release of hazardous materials occurred prior to our ownership or operation of the property or facility. We have not been identified as a potentially responsible party under CERCLA or comparable state laws.
- *Clean Air Act (CAA)* – The CAA and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and impose various monitoring and reporting requirements. Such laws and regulations may require pre-approval for the construction or modification of certain facilities expected to produce air emissions or result in an increase of existing air emissions. Such facilities must also strictly comply with air permits containing various emission and operational limitations, or requiring the use of emission control or abatement technologies.
- *National Ambient Air Quality Standards (NAAQS)* – The CAA requires the EPA to establish NAAQS for certain air pollutants. When NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the standard and become an "attainment area." If the counties in which our pipeline systems are located are designated as non-attainment areas for one or more pollutants, our pipeline systems' expansion or modification plans could be affected, possibly resulting in increased costs. In March 2008, the EPA issued final rules adopting new, more stringent NAAQS standards for ozone. The EPA is currently in the process of reconsidering those standards and, in January 2010, the EPA published a proposed rule to establish more stringent primary and secondary ozone NAAQS standards. EPA plans to complete the ozone standards rulemaking by July 29, 2011. Some of our operations will likely be affected by these new standards and the costs of compliance could be material. In January 2010, the EPA published a final rule establishing a more stringent nitrogen dioxide NAAQS standard of 100 parts-per-billion with a one hour averaging time. The impact of this standard is uncertain at this time, however, we could reasonably expect to incur significant costs if our pipeline systems could not demonstrate compliance with this new standard.
- *The Clean Water Act (CWA)* – The CWA and comparable 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 U.S. The discharge of

pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Federal and state regulatory agencies may impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

- *National Environmental Policy Act (NEPA)* – Natural gas transportation activities can be subject to review under NEPA, or comparable state laws. NEPA requires federal agencies, including the Department of the Interior or the FERC, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that addresses 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 in connection with any new approval that is required for construction, operation or the use of federal lands.

Climate Change

Our business is affected by existing and proposed regulation of greenhouse gases. A primary component of natural gas is methane, which is considered to be a greenhouse gas. Additionally, the burning of natural gas produces carbon dioxide, which is also a greenhouse gas. There are various legislative and regulatory measures proposed, and expected to be proposed, to reduce greenhouse gas emissions and establish more aggressive targets for renewable energy development. These climate change regulations and energy policies, if enacted, will likely impact our business. Measures to address climate change and greenhouse gas emissions are in various phases of development at international, federal, regional and state levels, which are outlined below:

- *International Climate Change Measures* – Some members of the international community have taken actions to address climate change issues on a global level. One such measure is the Kyoto Protocol, which is a treaty under which signatory countries, after ratification of the treaty, committed to a reduction of their greenhouse gas emissions. Although the U.S. has never ratified the Kyoto Protocol, Canada and Mexico both ratified the treaty. The U.S. participated in a recent United Nations Climate Conference in Cancun, Mexico, at which it reaffirmed its pledge to reduce greenhouse gas emissions over the next decade. The pledge made by the U.S. and other participating countries does not mandate emission reductions, nor is it legally binding.
- *Federal Climate Change Legislation* – It is possible that federal legislation to reduce greenhouse gas emissions will be enacted in the U.S. within the next few years. Although the form such legislation might take is unknown, we believe that a cap-and-trade or other market-based legislation that sets a price on carbon emissions could increase demand for natural gas, because less greenhouse gas emissions are generally associated with the use of natural gas as compared to the use of coal and oil. The actual impact on demand will, however, depend on specific legislative provisions that are adopted, including the level of emissions caps, allowances granted, offset programs established, cost of emissions credits and incentives provided to competing fossil fuels and lower carbon technologies like nuclear and renewable energy sources.
- *Federal Greenhouse Gas Regulations* – On January 2, 2011, the EPA's Tailoring Rule, a regulation that addresses the implementation of certain CAA permitting requirements for greenhouse gas emissions from certain existing or future stationary sources, became effective. Stationary sources of greenhouse gas emissions that are subject to these permitting requirements include engines and turbines located at compressor stations such as those operated by our pipeline systems. The Tailoring Rule establishes emissions thresholds and a phased timetable for permitting construction or modifications under the New Source Review Prevention of Significant Deterioration and operations under Title V Operating Permit programs.

  The EPA also issued the Mandatory Reporting of Greenhouse Gases Rule (GHG Reporting Rule), effective January 1, 2010, which requires large sources and suppliers in the U.S. to report greenhouse gas emissions. The emissions data will be used to inform the development of climate change policy. On December 30, 2010, an EPA final rule became effective that supplements the GHG Reporting Rule and requires, among other things, the inclusion of certain vented and fugitive greenhouse gas emissions from petroleum and natural gas systems (including pipeline transportation of natural gas) to be monitored and reported.

- *State and Regional Climate Change Measures* – In addition to recent activity at the federal level, several states have begun taking actions to control or reduce emissions of greenhouse gases, primarily through regional greenhouse gas cap-and-trade programs, renewable energy portfolio standards, and/or efficiency standards. The principal effect of such programs is likely to be limited to a reduction in demand for natural gas deliveries, if the programs, in fact, reduce fossil fuel use. In California, there are state-imposed reporting requirements that have increased our operating costs slightly. Additionally, the California Air Resources Board has released a cap-and-trade regulation that will (a) require large industrial users of fossil fuels to obtain allowances authorizing greenhouse gas emissions after January 1, 2012, and (b) impose allowance requirements upon natural gas importers commencing January 1, 2015. The costs of allowances are not yet able to be predicted, but could result in material reductions in demand for natural gas or in increased compliance costs for our pipeline systems.
- *Energy Legislation* – There are also ongoing legislative and regulatory efforts to encourage the use of cleaner energy technologies at the federal, state and local levels. While natural gas is a fossil fuel, it is generally associated with lower greenhouse gas emissions as compared to other fossil fuels, such as coal or oil. Future regulatory developments could, therefore, have a positive impact on our pipeline systems to the extent that natural gas is positioned as a preferred fossil fuel. On the other hand, some proposals for renewable energy and efficiency standards at both the federal and state level would require a material increase of renewable sources, such as wind and solar power generation, and establish incentives for energy efficiency and conservation. Such proposals, if enacted, could negatively impact natural gas demand. Although it is reasonably likely that energy policy and incentives will change over the next few years, we cannot predict the form of any new laws and regulations and cannot yet anticipate the precise impact on our pipelines systems or the demand for natural gas.
- *Impact of Climate Change on Our Business* – The regulation or restriction of greenhouse gas emissions could result in changes to the consumption and demand for natural gas. This could have adverse effects on our pipeline systems and our financial position, results of operations and future prospects. The physical effects associated with climate change may include changes in weather patterns, such as increases in storm intensity or temperature extremes, the availability or quality of water, or sea-level rise. These effects can impact supply and distribution chains or demand for certain products or services, or result in damage to facilities or decreased efficiency of equipment.

The impact of new or proposed greenhouse gas laws and regulations is not yet certain and we cannot estimate the effect of proposed legislation on our future financial position, results of operations or cash flow. It is also reasonably likely, however, that such legislation could materially increase our operating costs, including our cost of environmental compliance by requiring us to install additional equipment and potentially purchase emissions allowances or offset credits. Increases in costs of our pipeline systems' suppliers to comply with greenhouse gas legislation could also materially increase our costs of operations. Although many of these costs might be recoverable in the rates charged to our pipeline customers, recovery through these mechanisms is uncertain.

Costs of compliance with existing environmental laws and regulations have not had, nor are they expected to have, a material adverse effect upon our financial position, results of operations or cash flows. Environmental laws and regulations, however, are subject to change. The trend in environmental regulation is to increase protection of the environment and reduce instances of human exposure to hazardous materials or pollutants. There can be no assurances as to our pipeline systems' ability to obtain permits in the future or the amount or timing of future expenditures for environmental compliance or remediation. Changes to environmental regulations can result in increased compliance costs or additional operating restrictions, which could have an adverse effect on our pipeline systems, and the Partnership's financial position, results of operations and cash flows.

Safety Matters

Our pipeline systems are affected by existing and proposed pipeline safety regulations imposed by the U.S. Department of Transportation with respect to pipeline design, installation, testing, construction, operation, replacement and management.

The Pipeline Safety Improvement Act of 2002 (Pipeline Safety Act) requires pipeline companies to perform baseline integrity assessments on pipeline segments that exist in densely populated areas or near specifically identified sites that are designated as "high consequence areas" (HCAs). On December 29, 2006, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, referred to as PIPES of 2006, was enacted, which further amended the Pipeline Safety Act. Pipeline companies are required to perform the baseline integrity assessments within 10 years of the date of enactment and perform reassessments on a seven-year cycle. At this time, over 90 percent of the baseline assessments have been completed for our pipeline systems. The final baseline assessments are scheduled to be completed in 2011 and 2012. Approximately 50 percent of our pipeline systems are inspected in order to comply with the Pipeline Safety Improvement Act requirements for HCAs. Inspection programs for the remaining 50 percent of our pipeline systems are also developed to further manage risk.

There are various legislative and regulatory measures proposed and expected to be proposed to increase pipeline safety. These legislative and regulatory policies, if enacted, will likely impact our business, as well as other pipelines in the industry. While we believe that our pipeline systems are in substantial compliance with current applicable requirements, due to the possibility of these new or amended laws and regulations, there can be no assurance that future compliance with the requirements will not have a material adverse effect on our pipelines systems and the Partnership's financial position, results of operations and cash flows.

TITLE TO PROPERTIES

We believe that 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 and microwave towers. Our pipeline systems are constructed and operated on land owned by governmental authorities and others pursuant to leases, easements, rights-of-way, permits and licenses. We believe that our pipeline systems' properties are adequate and suitable for the conduct of their business in the future.

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 access across allotted lands located within each 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 feet 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. Northern Border exercised the option to renew on February 15, 2011. In conjunction with obtaining right-of-way access across tribal lands located within the exterior boundaries of the Fort Peck Indian Reservation, Northern Border also obtained right-of-way access across allotted lands located within the reservation boundaries. Most of the allotted lands are subject to a perpetual easement granted by the BIA for and on behalf of the individual Indian owners or obtained through condemnation. Several tracts are subject to a right-of-way grant that expires in 2015.

INSURANCE

The Partnership's operations and activities are insured under TransCanada's insurance programs, including property insurance, liability, automobile liability and workers compensation, in amounts that 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 operate our pipelines systems, in addition to providing services to the Partnership.

AVAILABLE INFORMATION

We make available free of charge, on or through our website (https://www.tcpipelineslp.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission (SEC). Information contained on our website is not part of this report.

Item 1A. Risk Factors

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. 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. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. All of the information included in this report, including the following discussion of risks and "Forward-Looking Statements," 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.

Risks Inherent in Our Business

The long-term financial conditions of our pipeline systems, except North Baja, are dependent on the continued availability of natural gas exiting the WCSB and the market demand for these volumes. Competition from pipelines that deliver natural gas from the WCSB to different market areas and competition from pipelines that deliver natural gas from other supply areas 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 natural gas prices, regulatory limitations and competition for capital from other North American natural gas producing basins that have lower exploration costs have adversely affected the development of additional reserves in Western Canada and the production in the WCSB in 2010 and may continue to do so in 2011.

Gas exiting the WCSB depends, in part, on the demand for natural gas within Western Canada. Western Canadian demand may increase as a result of increased demand for natural gas fired electricity generation and other industrial requirements, including the development of oil sands projects, which may require substantial amounts of natural gas. This higher Canadian demand may reduce the amount of natural gas available for downstream U.S. markets. In the longer term, a portion of the WCSB natural gas supply may come from the development of recently discovered natural gas shale resources such as Montney and Horn River in Western Canada and from proposed natural gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada. Cancellation, changes in route, and delays in the construction of such pipelines or such projects could adversely affect gas exiting the WCSB in the long term.

If the availability of natural gas exiting the WCSB was to decline, existing shippers on our pipeline systems, except North Baja, 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 might not extend their contracts for transportation if the cost of delivered natural gas from other producing regions into the markets served by our pipeline systems is more economical than the cost of natural gas delivered by our pipeline systems.

An increase in competition in the key markets served by our pipeline systems could arise from new ventures or expanded operations from existing competitors. For Great Lakes, the combination of growing supply from the Rockies and shale developments reaching Dawn through both new and available pipeline capacity, as well as reduced demand due to the economic environment has the potential to maintain competitive pressures on WCSB supply into the Midwest. Great Lakes is fully contracted on a long-haul basis to St. Clair, Michigan, near the Dawn, Ontario storage hub through October 2011; however, if the transport of natural gas from the Rockies and Mid-Continent shales eastward to Dawn becomes more economical on competitive pipeline routes, then those supplies could reach the eastern zone of Great Lakes' market area and displace Great Lakes' long-haul volumes.

Similarly, for Northern Border, the combination of growing supply from the Rockies and shale developments reaching the Chicago market region through both new and available pipeline capacity, as well as reduced demand due to the economic environment has the potential to maintain competitive pressures on WCSB supply into the Midwest markets served by Northern Border. Northern Border is essentially fully contracted through March 2012; 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 various factors, including:

- the available 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 through their transportation rates or through their access to upstream supplies, as well as the proposed construction by other companies of additional pipeline capacity;
- contract expirations on competing pipelines, which can change our pipeline systems' relative competitiveness;
- changes in rate design upstream or downstream of our pipeline systems, which can affect our pipeline systems' relative competitiveness in attracting volumes;

- 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' abilities 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. Additionally, when the forward natural gas basis differentials do not support maximum rates, Great Lakes and Northern Border may sell portions of their capacity at discounted rates. Great Lakes' and Northern Border's inability to renew existing contracts at maximum rates, or at all, or to enter into new long-term shipper contracts for upcoming excess capacity will have an adverse impact on their revenues and, as a result, cash distributions made to us.

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

Under the NGA, interstate transportation rates must be just, reasonable and not unduly discriminatory. Our pipeline systems are subject to extensive regulation by the FERC, the U.S. Department of Transportation, the EPA 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;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- income tax allowance policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- standards of conduct for business relations with certain affiliates; and
- integrity and safety of our pipeline systems and related operations.

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

- the federal regulations under which our pipeline systems will operate in the future;
- the effect that regulation will have on the 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.

Action by the FERC on currently pending regulatory 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 increases in their costs, such as additional costs related to environmental matters including any climate change regulation, or increased costs of compliance with regulations, 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.

Our pipeline systems are required to comply with all applicable FERC administered statutes, rules, regulations and orders. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

Composition of Proxy Groups for Rates of Return Determinations – The FERC uses proxy groups of publicly traded companies with business models similar to the pipeline for which a rate determination is sought in order to determine an appropriate return on equity (ROE) for that pipeline. In a 2008 Policy Statement, the FERC expanded the criteria for proxy group companies, thereby permitting the inclusion of master limited partnerships (MLPs). The effect of the FERC's evolving policy and precedent with regard to proxy groups, and the availability of risk-appropriate companies and MLPs for inclusion in a proxy group at the time of a rate case, may impact the ROEs for any of our pipeline systems involved in a rate case.

If our pipeline systems do not make additional capital expenditures sufficient to offset depreciation expense, which would result in a declining rate base, 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.

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

The amount of cash we have on a quarterly basis to distribute to our common unitholders depends upon numerous factors, some 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 global economic and financial market crisis in late 2008 and into 2009 has had, and may continue to have, a negative effect on our business.

The global economic and financial market crisis in late 2008 and into 2009 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. Although general economic conditions have improved, recovery for certain sectors has been slower. Many natural gas producers, natural gas marketing companies and end users have been negatively affected by current economic conditions, as evidenced by reduced drilling and natural gas development in the WCSB, which is a critical natural gas supply source for our pipeline systems, except North Baja. 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 revenues 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.

Although conditions in the credit and financial markets have largely returned to pre-crisis levels, there can be no assurance that the recovery in market conditions will be sustained or that our results will not be materially and adversely affected in the future. 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.

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 common 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 common unit generated from operations.

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 percent of its 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 are able to contract for comparable volumes from other customers at favorable rates.

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 HCAs, where a leak or rupture could do the most harm. The final rule resulted from the enactment of the Pipeline Safety Act. The results of the integrity management programs could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure their continued safe and reliable operation. Additionally, the possibility of new or amended laws and regulations could have a material adverse effect on our results of operations or financial position. Any failure to comply with the 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 laws and regulations that could impose costs for compliance with environmental protection and operational safety standards.
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 environmental and safety 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, or install pollution control equipment. In addition, due to several recent third party pipeline incidents, various legislative and regulatory reforms associated with pipeline safety and integrity issues have been proposed, including reforms that would require increased periodic inspections. It is uncertain which proposed laws, regulations or reforms, if any, will be adopted and what impact they might ultimately have on our operations or financial results.

Under certain environmental laws and regulations, we may be exposed to substantial liabilities for any pollution or contamination that arises in connection with our operations. In particular, the costs of recently adopted and future legislative and regulatory requirements related to greenhouse gas emissions and climate change may increase our operating costs materially or adversely affect demand. If we are unable to recover or pass through a significant level of our costs related to environmental matters, safety or greenhouse gas regulatory requirements, it could have a material adverse effect on our results of operations.

On April 7, 2010, the EPA published an Advance Notice of Proposed Rulemaking to solicit comments with respect to the EPA's reassessment of current regulations, promulgated under TSCA, governing the authorized use of polychlorinated biphenyls (PCBs) in certain equipment. The proposed changes could require notification to the EPA when PCBs are discovered in any pipeline system, a phase out and eventual elimination of PCB use in pipeline systems and air compressor systems and the immediate elimination of the storage of PCB equipment for reuse. These changes, if finalized as proposed, could potentially have a material impact on certain of our pipeline systems.

Great Lakes Requests for Information –

- By letter dated December 28, 2009, the EPA required Great Lakes to provide information regarding its natural gas compressor stations in the states of Minnesota, Wisconsin and Michigan as part of the EPA's investigation of Great Lakes compliance with the CAA. On May 28, 2010, Great Lakes submitted its final response to the EPA. To date, Great Lakes has received one request from EPA for clarification regarding submitted information. The potential effects on Great Lakes that may arise as a result of this information request are not determinable at this time.
- By letter dated July 26, 2010, the EPA required Great Lakes to provide information regarding one natural gas compressor station located in Minnesota. The potential effects on Great Lakes that may arise as a result of this information request are not determinable at this time.

Minnesota Pollution Control Agency (MPCA) Data Request – In November 2010, Northern Border and Great Lakes received verbal data requests from the MPCA related to Title V operating permits for all facilities located in Minnesota. The information was submitted to the MPCA in December 2010. The potential effects on Northern Border and Great Lakes that may arise as a result of this information request are not determinable at this time.

We make assumptions and develop expectations about possible expenditures related to safety and environmental matters based on current laws and regulations and current interpretations of those laws and regulations. If the laws or regulations, or the interpretations of laws or regulations change, our assumptions may change. Our regulatory rate structure and our contracts with customers might not necessarily allow us to recover capital costs we incur to comply with the new environmental and safety regulations. Also, we might not be able to obtain or maintain from time to time all required regulatory approvals for development of new projects or continued operation of existing systems. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain and comply with them, the operation of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our results of operations.

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

As at December 31, 2010, Great Lakes, Northern Border and Tuscarora had $392.0 million, $541.0 million and $30.9 million of debt outstanding, respectively. Of the debt outstanding, Great Lakes and Tuscarora have $19.0 million and $0.8 million of debt maturing in 2011, respectively. Their respective levels of debt could have important consequences to Great Lakes, Northern Border and Tuscarora, including the following:

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

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 and credit 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 maximizing 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 may impact the ability of our pipeline systems to access capital and credit markets for debt under reasonable terms.

If conditions in the U.S. capital markets and credit markets undergo a significant deterioration, 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 appointed members, half of whom are designated by us and half of whom are designated by TransCanada. Currently, there are four members appointed to the management committee and all decisions require unanimous consent. An executive committee consisting of two appointed members – one Partnership committee member and one TransCanada committee member, who also serves as the president of Great Lakes – has all of the powers of the management committee in the management of Great Lakes' business. Because of these provisions, without the concurrence of TransCanada, we may be unable to cause Great Lakes to take or not to take certain actions, even though those actions may be in the best interest of us or Great Lakes.

Northern Border's management committee consists of four members, two of whom are designated by us and two of whom are designated by an affiliate of ONEOK 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' 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 flows.

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 stand-alone management resources to operate without services provided by TransCanada. 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.

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 at December 31, 2010, the Partnership had $513.9 million of debt outstanding, including the revolving credit and term loan agreement (Senior Credit Facility) and Senior Notes. 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 the Partnership's Second Amended and Restated Agreement of Limited Partnership (Partnership Agreement);
- incurring additional debt; and
- distributions to unitholders.

Any future debt may contain similar restrictions.

Our Senior Credit Facility matures in December 2011 and we may be unable to refinance in a timely manner or on terms acceptable to us, if at all.

Our Senior Credit Facility matures on December 12, 2011, at which time all amounts outstanding thereunder will be due and payable. We currently expect to renew the facility, but there can be no assurance that we will be able to refinance the Senior Credit Facility on terms and conditions acceptable to us, or at all, or on a timely basis. In addition, credit or financial market disruptions such as those experienced in the U.S. in 2008 and 2009 may have a material adverse effect on our ability to refinance the facility on a timely basis and on terms acceptable to us, if at all. Without a replacement credit facility, it is likely that we would have insufficient capital to support our development and capital expenditure plans, which could have a materially negative impact to existing common unitholders.

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.

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 at December 31, 2010, the partnership had $483.0 million outstanding under the Senior Credit Facility (2009 – $484.0 million), all of which is initially exposed to 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, 2010, the variable interest rate exposure related to $375.0 million of the $483.0 million outstanding debt under the Senior Credit Facility was mitigated by fixed interest rate swap arrangements.

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

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.
Unlike a corporation, our Partnership Agreement requires us to make quarterly distributions to our unitholders of all available cash, reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per common 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 66⅔ percent of the outstanding common 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 common units owned by our General Partner and its affiliates. The ownership of an aggregate of 37.0 percent of the outstanding common 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 common 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 percent or more of any class of common units then outstanding, that person or group will lose voting rights with respect to all of its common 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 common 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 the Partnership and dilute the interests of unitholders in distributions by the Partnership. Our Partnership Agreement does not give the unitholders the right to approve the issuance by us of equity securities ranking junior to the common units at any time.

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

Unitholders may not have limited liability in some circumstances.

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

- the Partnership 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 the Partnership's business,

then unitholders could be held liable in some circumstances for the Partnership's obligations to the same extent as a general partner. In addition, under some circumstances a unitholder may be liable to the Partnership 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 37 percent of our common units, come to own 80 percent 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, North Baja or Tuscarora might be converted into a corporation, which would result in Great Lakes, Northern Border, North Baja 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, North Baja 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, through its subsidiaries, controls our General Partner, which has responsibility for conducting our business and managing our operations. TC PipeLines GP, Inc., 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 our General Partner and its affiliates have duties to manage the General Partner in a manner that is beneficial to its stockholders. At the same time, our General Partner has duties to manage our partnership in a manner that is beneficial to us. Therefore, our General Partner'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 our General Partner;
- under our Partnership Agreement, our General Partner determines which costs incurred by it and its affiliates are reimbursable by us;
- affiliates of our General Partner may compete with us in certain circumstances;
- our General Partner 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 conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law; and
- TransCanada, through wholly-owned subsidiaries, is the operator of all of our pipeline systems. This operator role along with its ownership interests in our pipeline systems may influence 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, 2010, we paid fees and reimbursements to our General Partner in the amount of $2.2 million (2009 – $2.1 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.

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

Current 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.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.
The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax law or interpretations thereof could make it difficult or impossible to meet the requirements for us to be treated as a partnership for federal income tax purposes. These modifications could cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units. We are unable to predict whether or not such changes, if any, will ultimately occur. Any modifications to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively affect the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

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 operating partnerships, which are generally treated as flow-through entities for income tax purposes, and as such the income from our pipeline systems generally has 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 2010, Great Lakes recorded a Michigan business tax of $5.3 million relating to a partnership level tax, adopted by Michigan in 2008, of which the Partnership's share of the tax was $2.5 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 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 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 taxable 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 a unitholder was allocated for a common unit which decreased the unitholder's 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 on the sale of common units, whether or not representing a gain, may be ordinary income to unitholders due to potential recapture of items such as depreciation recapture. If the IRS were to successfully contest some conventions we use, unitholders could recognize more taxable gain on the sale of common units than would be the case under those conventions without the benefit of decreased taxable 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 are 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.
Because we cannot match transferors and transferees of 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 taxable gain from the sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to unitholders' tax returns.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the General Partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.
For income tax purposes and pursuant to the Partnership Agreement, when we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our General Partner. If our valuation methodology were not sustained upon an IRS challenge, there may be a shift of income, gain, loss and deduction between certain unitholders and the General Partner, which may be unfavorable to such unitholders. Our valuation methodology is also used in certain computations and allocations relating to tax basis adjustments and the tax treatment of unitholders' gain on sale of common units.

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 or character of taxable 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 percent 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 percent 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 Arizona, California, Illinois, Indiana, Iowa, Michigan, Minnesota, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, Texas and Wisconsin. Should we make acquisitions or expand our business, we may own assets or conduct business in additional states. Most of these states 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 U.S. 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

A description of our properties and the properties of our pipeline systems is included in Part 1, Item 1. "Business – Title to Properties," and is incorporated herein by reference.

Item 3. Legal Proceedings

Great Lakes v. Essar Steel Minnesota LLC, et al. (Essar) – In October 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar for breach of contract. Essar is a party to a transportation contract for a term starting July 1, 2009 through March 31, 2024. The fifteen-year contract has a total approximate value of $33.0 million. Essar has refused to honor their contractual obligations. Great Lakes is seeking recovery of all sums due, including all future sums due under the contract. The case is currently in the discovery phase.

In addition to this proceeding, the Partnership and our pipeline systems are involved in various pending or potential legal actions in the ordinary course of business. While management is unable to predict the ultimate outcome of these actions, and because of the inherent uncertainty of litigation, we cannot provide assurance that the resolution of any particular claim or proceeding will have a favorable or unfavorable material effect on the Partnership's financial position, results of operations or cash flows for the period in which the resolution occurs.

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 have been quoted on the NASDAQ Global Select Market since May 1999 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
	High	Low	Common Unit
2010			
First Quarter	**$38.09**	**$34.40**	**$0.730**
Second Quarter	**$40.96**	**$34.72**	**$0.730**
Third Quarter	**$46.50**	**$40.35**	**$0.750**
Fourth Quarter	**$52.00**	**$46.21**	**$0.750**
2009			
First Quarter	$30.44	$23.62	$0.705
Second Quarter	$36.43	$29.71	$0.730
Third Quarter	$39.14	$34.82	$0.730
Fourth Quarter	$41.10	$35.17	$0.730

As at February 16, 2011, there were 71 registered holders of common units and approximately 21,500 beneficial owners of common units, including common units held in street name.

The Partnership currently has 46,227,766 common units outstanding, of which 29,142,935 are held by the public, 11,287,725 are held by TransCan Northern Ltd., and 5,797,106 are held by our General Partner. The common units represent an aggregate 98 percent limited partner interest and the general partner interest represents an aggregate two percent general partner interest in the Partnership.

Cash Distributions

The General Partner receives two percent of all cash distributions in regard to its general partner interest and is also entitled to incentive distributions as described below. The 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; and
- provide funds for cash distributions to unitholders and the General Partner in respect of any one or more of the next four quarters.

The incentive distribution provisions were amended in July 2009. As a result, the General Partner receives 15 percent of quarterly amounts distributed in excess of $0.81 per common unit, and a maximum of 25 percent of quarterly amounts distributed in excess of $0.88 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 2010, the Partnership made cash distributions to unitholders and the General Partner that amounted to $138.7 million compared to $117.0 million in 2009. These payments represented $0.73 per common unit for the quarters ended December 31, 2009, March 31, 2010 and June 30, 2010 and $0.75 per common unit for the quarter ended September 30, 2010. On February 14, 2011, the Partnership paid a cash distribution of $35.4 million to unitholders and the General Partner, representing a cash distribution of $0.75 per common unit for the quarter ended December 31, 2010. The distribution was allocated in the following manner: $34.7 million to the unitholders as of the close of business on January 31, 2011 (including $4.3 million to the General Partner as holder of 5,797,106 common units and $8.5 million to TransCanada as indirect holder of 11,287,725 common units), and $0.7 million to the General Partner in respect of its two percent general partner interest.

Item 6. Selected Financial Data

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

(millions of dollars, except per common unit amounts)	**2010**	2009[a]	2008[a]	2007[a][b]	2006[a][c]
Income Data (for the year ended December 31)					
Equity income from investment in Great Lakes	**58.7**	59.1	57.3	49.0	–
Equity income from investment in Northern Border	**67.3**	40.3	65.3	61.2	56.6
Equity income from investment in Tuscarora	**–**	–	–	–	5.9
Transmission revenues	**69.1**	67.9	64.5	49.8	23.0
Financial charges and other	**(25.6)**	(29.3)	(34.6)	(38.7)	(21.7)
Net income	**137.1**	106.1	123.0	94.7	49.1
Basic and diluted net income per common unit	**$2.91**	$2.34	$2.73	$2.48	$2.39
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$2.960**	$2.895	$2.815	$2.630	$2.350
Balance Sheet Data (at December 31)					
Total assets	**1,650.5**	1,675.1	1,701.1	1,732.4	1,008.1
Long-term debt (including current maturities)	**513.9**	541.3	536.8	573.4	468.1
Partners' equity	**1,112.5**	1,103.5	875.6	900.1	303.9

(a) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

(b) The Partnership acquired a 46.45 percent interest in Great Lakes on February 22, 2007. The equity method is used to account for the Partnership's investment in Great Lakes.

(c) The Partnership acquired an additional 20 percent interest in Northern Border on April 6, 2006. The equity method is used to account for the Partnership's investment in Northern Border. The Partnership accounted for its 49 percent investment in Tuscarora using the equity method until December 19, 2006 and began consolidating Tuscarora's operations upon acquisition of the additional 49 percent general partner interest.

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

The following discussion of the financial condition and results of operations of the Partnership and its pipeline systems should be read in conjunction with the financial statements and notes thereto of the Partnership, Great Lakes and Northern Border included elsewhere in this report. See Part II, 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. The discussion below includes forward-looking statements that are subject to risks and uncertainties that may result in actual results differing materially from the statements we make. These risks and uncertainties are discussed further in Part 1, Item 1A. "Risk Factors."

OVERVIEW

TC PipeLines, LP was formed in 1998 as a Delaware limited partnership to acquire, own and participate in the management of energy infrastructure businesses in North America.

To date, our investments have been in interstate natural gas pipeline systems that transport natural gas to a variety of markets in the U.S. and Eastern Canada. Our pipeline systems derive their operating revenue from the transportation of natural gas. Our pipelines are regulated by the FERC and are operated by TransCanada. With the exception of North Baja, these pipelines comprise critical links for the transportation of natural gas from the WCSB to U.S. markets.

Our investments are:

	Ownership		System Specifications	
	Percentage	Date Acquired	Miles	Capacity (MMcf/d)
Great Lakes	46.45	February 2007	2,115	2,300 (summer design) 2,500 (winter design)
Northern Border	30.00 20.00 50.00	May 1999 April 2006	1,398	2,374 (design)
North Baja	100.00	July 2009	86	500 (southbound design) 600 (northbound design)
Tuscarora	49.00 49.00 2.00 100.00	September 2000 December 2006 December 2007	305	230 (design)

2010 Year in Review

- *Partnership Distribution* – In 2010, we continued to focus on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low-risk profile. In October 2010, we increased our quarterly cash distribution rate by three percent to $0.75 per common unit, or $3.00 per common unit on an annualized basis.
- *Northern Border Contract Volumes* – In 2010, average daily scheduled volumes on Northern Border's pipeline system was 2,471 MMcf/d compared to 1,934 MMcf/d in 2009. This increase was primarily due to Northern Border being fully contracted at the end of 2010 due to increased demand for Northern Border's transportation services compared to 2009. Substantially all of Northern Border's capacity has been sold through March 2012.
- *Great Lakes Contract Volumes* – Great Lakes' largest shipper, TransCanada PipeLines Limited, has held contracts for approximately 1.3 MMDth/d for over 40 years. Beginning November 1, 2010, TransCanada PipeLines Limited reduced its contract demand to 961 MDth/d; however, Great Lakes resold all available long-haul capacity and remains fully contracted through October 31, 2011.
- *Great Lakes Rate Case Settlement* – As a result of extensive settlement negotiations, in July 2010, the FERC approved a stipulation and agreement (GL Settlement) without modification. As approved, the GL Settlement resulted in a reduction in rates and will apply to all current and future shippers on Great Lakes' system. Please read "Regulatory Environment – FERC Rating Proceedings – Great Lakes Rate Proceeding" in this section for additional information with respect to the GL Settlement.

- *Great Lakes Backhaul Service* – In 2010, Great Lakes installed facilities to increase its ability to provide firm backhaul (east to west) transportation. As of November 1, 2010, Great Lakes began providing an incremental 440 MDth/d of transportation service from St. Clair, Michigan to Emerson, Manitoba, Canada.
- *North Baja Bi-directional Flow* – In March 2010, North Baja transported natural gas northbound into the U.S. for the first time since the pipeline completed its expansion to allow for bi-directional flows in April 2008. The northbound service provides North Baja with additional market opportunities.
- *Yuma Lateral* – In March 2010, the Partnership acquired the expansion facilities and contracts in place for an expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma, Arizona (Yuma Lateral). The Yuma Lateral was placed in service in March 2010.
- *Northern Border Princeton Lateral* – In December 2010, Northern Border accepted the certificate issued by the FERC to construct the Princeton Lateral Project authorizing Northern Border to construct, own and operate 8.7 miles of 16-inch diameter pipeline and associated facilities. The project is fully subscribed for a 10-year term and is expected to be in service by fourth quarter 2011. The total cost of the project is expected to be approximately $18 million, of which the Partnership expects to contribute approximately $4.5 million.
- *TransCanada Mainline Interim Toll Application* – Because the ability and willingness of natural gas shippers to utilize a pipeline system over alternative pipelines can be impacted by relative transportation rates and the volume of natural gas delivered to markets supplied by that system from other supply sources and storage facilities, the demand for natural gas services on Great Lakes, Northern Border and Tuscarora, may be impacted by changes in TransCanada Mainline tolls. In January 2011, TransCanada filed an application with Canada's National Energy Board (NEB) for approval of interim 2011 tolls calculated in accordance with TransCanada Mainline's 2007-2011 settlement currently in effect, and the NEB approved the application, as filed, in February 2011. An application and proceeding regarding 2011 final tolls is expected to follow.

FACTORS THAT IMPACT OUR BUSINESS

Factors that may impact demand for transportation service on any one system include the availability of natural gas supply at the pipeline system's receipt points, the ability and willingness of natural gas shippers to utilize that system over alternative pipelines, transportation rates compared to other systems and the volume of natural gas delivered to the same market from other supply sources and storage facilities.

Prevailing market conditions and dynamic competitive factors in North America (particularly reduced natural gas exiting the WCSB, increased supply from other supply basin market areas served by our pipelines and the economic environment affecting the demand for natural gas) will continue to impact the value of transportation on our pipeline systems and their ability to market available capacity. Our pipeline systems actively market their available capacity and work closely with customers, including natural gas producers and end users, to ensure our pipelines are offering attractive services and competitive rates.

Supply

The primary source of natural gas transported by our pipeline systems, excluding North Baja, is the WCSB. Gas exiting the WCSB is dependent upon WCSB natural gas production levels, demand for natural gas in Western Canada, and the volume of natural gas injected into natural gas storage in Western Canada. Despite declines in drilling activity in the WCSB in recent years, we expect drilling in the WCSB to recover over the long term as supply costs and royalty structures become more competitive. In addition, the ultimate supply potential of the WCSB has been improving due to improved economic access to its unconventional resources including shale gas, tight gas and coal-bed methane. In particular, the Horn River and Montney shale plays have demonstrated encouraging results which are expected to improve supply available from the WCSB in 2011 and 2012. In the longer term, reserves from northern natural gas may increase the supply coming out of the WCSB.

Demand

Demand for natural gas is impacted by a variety of factors including weather conditions, economic conditions, government regulations and the availability and price of alternative energy sources. North American natural gas demand in 2010 grew compared to 2009 levels due to a rebound in economic activity and a warmer than normal summer in our pipeline systems' market regions which increased natural gas demand for electric generation. We expect that demand for natural gas will improve modestly along with the economic recovery, and that most of the growth in demand will result from increased demand for natural gas-fired electric generation.

Competition

Due to excess pipeline capacity, there is currently increased competition amongst natural gas pipelines for the transportation of gas exiting the WCSB. Factors impacting the competition for gas exiting the WCSB include levels of firm transportation contracts on each pipeline, demand for natural gas in the regions served by each pipeline and relative transportation values on each pipeline.

Contracting

The majority of our pipeline systems' natural gas transportation services are provided through firm service transportation contracts with a reservation charge to reserve pipeline capacity, regardless of use, for the term of the contract. The revenues associated with capacity under firm service transportation contracts are not subject to fluctuations caused by changing supply and demand conditions, competition and customers. Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges (or utilization fees) based on distance and the volume of natural gas they transport.

The following table provides information with respect to the revenue composition for our pipeline systems for the year ended December 31, 2010:

	2010 Revenue Composition		
	Firm Contracts		
	Capacity Reservation Charges	Variable Usage Fees	Interruptible Contracts & Other Services
Great Lakes	95%	3%	2%
Northern Border	89%	8%	3%
North Baja	99%	1%	0%
Tuscarora	100%	0%	0%

New major long-haul pipeline projects are typically underpinned by contracts for an original term equal to or greater than ten years. When this original term expires, shippers typically renew on an annual basis. Terms for interruptible transportation services range from day-to-day to multiple years. With the interconnection of the Bison pipeline to Northern Border, terms for transportation services for related capacity on Northern Border have contract terms of ten years. However, contract renewals for Great Lakes and the remaining Northern Border contracts are generally on an annual basis. Tuscarora has long-term contracts for the majority of its capacity with term expiries after 2016. Similarly, North Baja has long-term contracts for a substantial portion of its capacity with terms that mature between 2022 and 2028.

Average Daily Scheduled Volumes

The table below provides historical information on the average daily scheduled volumes for Great Lakes and Northern Border from the past three years:

	Average Daily Scheduled Volumes[a]		
December 31 *(million cubic feet per day)*	**2010**	2009	2008
Great Lakes	**2,203**	1,992	2,143
Northern Border	**2,471**	1,934	2,291

[a] Average daily scheduled volumes represent volumes of natural gas, irrespective of path or distance transported, from which variable usage fee revenue is earned. Average daily scheduled volumes are not presented for North Baja and Tuscarora as Partnership Cash Flows and Net Income from these investments are underpinned by long-term firm contracts and do not vary significantly with changes in utilization.

Great Lakes

Average daily scheduled volumes on Great Lakes' pipeline system in 2010 increased to 2,203 MMcf/d compared to 1,992 MMcf/d in 2009 primarily due to higher utilization of long-term firm contracts by Great Lakes' major shipper, TransCanada PipeLines Limited, during the traditional summer storage-fill season. Increases in volumes related to higher utilization of long-term firm contracts have a minimal impact on revenue earned from these contracts.

Great Lakes' long-haul capacity contracts are generally subject to annual renewals. Contracting occurs throughout the year; however, shippers typically contract on Great Lakes for the upcoming natural gas year starting on November 1 of each year. As a result, Great Lakes is currently fully contracted through October 2011. Great Lakes' largest shipper, TransCanada PipeLines Limited has 576 MDth/d of long-haul capacity under contract expiring on October 31, 2011. Negotiations related to these contracts are currently underway.

Northern Border

Average daily scheduled volumes on Northern Border's pipeline system in 2010 increased to 2,471 MMcf/d compared to 1,934 MMcf/d in 2009. Demand for transportation on Northern Border improved during 2010 primarily due to an increase in the transportation value that was available to shippers utilizing Northern Border transportation services. The increase in transportation value was due to a number of factors, including the completion of other pipeline projects that moved Mid-Continent natural gas supply to eastern markets and the relative economic value of Northern Border services compared with other transportation paths and available markets, resulting in an increase in demand for Northern Border's transportation services.

Northern Border's capacity is generally subject to annual contract renewals, which occur throughout the year. Substantially all of Northern Border's capacity has been sold through March 2012.

In January 2011, TransCanada placed in service the Bison Pipeline Project that extends from the Powder River Basin producing region in Wyoming to an interconnection with the Northern Border system in Morton County, North Dakota. Northern Border has secured 10-year contracts with the Bison shippers, at a discounted rate, for approximately 407 MMcf/d of capacity from Port of Morgan, Montana to Ventura, Iowa.

Outlook

Due to the relatively short-term contract profiles for Great Lakes and Northern Border, these systems may experience operating revenue volatility. We believe Great Lakes and Northern Border to be fundamental and competitive components of the natural gas pipeline infrastructure exiting the WCSB. The level of contracting and, accordingly, revenues post-October 2011 for Great Lakes and post-March 2012 for Northern Border will depend on the factors of supply, demand and competition described above.

North Baja and Tuscarora are expected to provide stable revenues, subject to any FERC decisions on rates, as the capacity on both pipelines is contracted for the long-term.

REGULATORY ENVIRONMENT

FERC Rate Proceedings

Great Lakes Rate Proceeding – On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 instituting an investigation pursuant to Section 5 of the NGA. The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable. As a result of extensive settlement negotiations, in July 2010, the FERC approved the GL Settlement without modification, establishing the terms pursuant to which all matters in the GL Rate Proceeding were resolved. The GL Settlement was effective May 1, 2010 and applies to all current and future shippers on Great Lakes' system.

Under the terms of the GL Settlement, reservation rates on Great Lakes' pipeline system were reduced eight percent, Interruptible Transportation (IT) rates were increased, and the depreciation rate for Great Lakes' transmission plant was also reduced. IT revenue sharing was terminated by the GL Settlement, and a new limited revenue sharing provision was agreed to for jurisdictional revenues that Great Lakes receives in excess of $500 million during the period between November 1, 2010 and October 31, 2012.

The GL Settlement rates will remain in effect through at least November 30, 2011. The GL Settlement includes a moratorium on participants and customers filing any NGA Section 5 rate case to place new rates into effect prior to November 1, 2012. There is also a moratorium on Great Lakes filing a general NGA Section 4 rate case to place new rates into effect prior to December 1, 2011. In addition, the GL Settlement requires Great Lakes to file a NGA Section 4 general rate case no later than November 1, 2013.

Environmental Matters

Impact of Climate Change on Our Business – The regulation or restriction of greenhouse gas emissions could result in changes to the consumption and demand for natural gas. This could have adverse effects on our pipeline systems, and our financial position, results of operations and future prospects. The physical effects associated with climate change may include changes in weather patterns, such as increases in storm intensity or temperature extremes, the availability or quality of water, or sea-level rise. These effects can impact supply and distribution chains or demand for certain products or services, or result in damage to facilities or decreased efficiency of equipment.

The impact of new or proposed greenhouse gas laws and regulations is not yet certain and we cannot estimate the effect of proposed legislation on our future financial position, results of operations or cash flow. It is also reasonably likely, however, that such legislation could materially increase our operating costs, including our cost of environmental compliance by requiring us to install additional equipment and potentially purchase emission allowances or offset credits. Increases in costs of our pipeline systems' suppliers to comply with greenhouse gas legislation could also materially increase our costs of operations. Although many of these costs might be recoverable in the rates charged to our pipeline customers, recovery through these mechanisms is uncertain.

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. The Partnership calculates Partnership cash flows as net income, less North Baja's net income contribution prior to acquisition, plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja and Tuscarora, and cash distributions received in excess of equity income from the Partnership's equity investments, Great Lakes and Northern Border, net of distributions declared to the General Partner. Partnership cash flows before General Partner distributions represent Partnership cash flows prior to distributions declared to the General Partner.

RESULTS OF OPERATIONS OF TC PIPELINES, LP

Our general partner interests in Great Lakes and Northern Border and ownership of North Baja and Tuscarora were our only material sources of income in 2010. Therefore, our results of operations and Partnership cash flows were influenced by and reflect the same factors that influenced the financial results of Great Lakes, Northern Border, North Baja and Tuscarora. See Item 1. "Business."

NET INCOME

The Partnership uses the non-GAAP financial measure "Net income prior to recast" as a financial performance measure. Net income prior to recast excludes North Baja's net income for periods prior to July 1, 2009, the date on which the Partnership acquired North Baja. The acquisition of North Baja from TransCanada was accounted for as a transaction under common control, similar to a pooling of interests, whereby the Partnership's historical financial information was recast to include the net income of North Baja for all periods presented, which included income which did not accrue to the Partnership's general partner interest or to the Partnership's common units, but rather accrued to North Baja's former parent.

Net income prior to recast is presented to enhance investors' understanding of the way management analyzes the Partnership's financial performance. Net income prior to recast is provided as a supplement to GAAP financial results and is not meant to be considered in isolation or as a substitute for financial results prepared in accordance with GAAP.

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 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 and Northern Border, representing 100 percent of each entity's operations for the given period.

Year Ended December 31, 2010 *(millions of dollars)*	**Total**	Other Pipes[a]	Corporate[b]	Great Lakes	Northern Border[c]
Transmission revenues	**69.1**	69.1	–	262.4	295.1
Operating expenses	**(13.0)**	(13.0)	–	(59.2)	(74.0)
General and administrative	**(4.4)**	–	(4.4)	–	–
Depreciation	**(15.0)**	(15.0)	–	(40.5)	(61.5)
Financial charges and other	**(25.6)**	(4.2)	(21.4)	(30.9)	(23.4)
Michigan business tax	**–**	–	–	(5.3)	–
				126.5	136.2
Equity income	**126.0**	–	–	58.7	67.3
Net income	**137.1**	36.9	(25.8)	58.7	67.3

Year Ended December 31, 2009 *(millions of dollars)*	**Total**	Other Pipes[a]	Corporate[b]	Great Lakes	Northern Border[c]
Transmission revenues	**50.9**	50.9	–	289.7	249.2
Operating expenses	**(7.9)**	(7.9)	–	(66.5)	(70.8)
General and administrative	**(6.2)**	–	(6.2)	–	–
Depreciation	**(10.9)**	(10.9)	–	(58.5)	(61.9)
Financial charges and other	**(27.5)**	(4.1)	(23.4)	(31.9)	(34.4)
Michigan business tax	**–**	–	–	(5.4)	–
				127.4	82.1
Equity income	**99.4**	–	–	59.1	40.3
Net income prior to recast	**97.8**	28.0	(29.6)	59.1	40.3
North Baja's contribution prior to acquisition[d]	**8.3**	8.3	–	–	–
Net income[d]	**106.1**	36.3	(29.6)	59.1	40.3

Year Ended December 31, 2008 *(millions of dollars)*	**Total**	Other Pipes[(a)]	Corporate[(b)]	Great Lakes	Northern Border[(c)]
Transmission revenues	**31.6**	31.6	–	287.1	293.1
Operating expenses	**(5.4)**	(5.4)	–	(67.1)	(78.0)
General and administrative	**(4.1)**	–	(4.1)	–	–
Depreciation	**(6.9)**	(6.9)	–	(58.5)	(61.1)
Financial charges and other[(c)]	**(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 prior to recast	**107.7**	15.0	(29.9)	57.3	65.3
North Baja's contribution prior to acquisition[(d)]	**15.3**	15.3	–	–	–
Net income[(d)]	**123.0**	30.3	(29.9)	57.3	65.3

(a) "Other Pipes" includes the results of North Baja and Tuscarora.

(b) "Corporate" includes the costs of the Partnership, but excludes the costs of its subsidiaries.

(c) The Partnership owns a 50 percent general partner interest in Northern Border. Equity income from Northern Border includes the twelve-year amortization of a $10.0 million transaction fee paid to the operator of Northern Border at the time of the additional 20 percent acquisition in April 2006.

(d) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

(e) In 2008, Northern Border's financial charges, net and other, included a $16.2 million gain on the sale of Bison Pipeline LLC (Bison).

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009

Net income increased $31.0 million to $137.1 million in 2010 compared to $106.1 million in 2009. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast increased $39.3 million to $137.1 million in 2010 compared to $97.8 million in 2009. This increase was primarily due to increased equity income from Northern Border, net income from North Baja for a full year in 2010 compared to six months in 2009 and lower general and administrative costs and lower financial charges at the Partnership level.

Equity income from Northern Border was $67.3 million in 2010, an increase of $27.0 million compared to 2009. The increase in equity income was primarily due to increased transmission revenues and reduced financial charges, partially offset by higher operating expenses. Northern Border's transmission revenues increased $45.9 million in 2010 compared to 2009 primarily due to increased demand for transportation services on Northern Border. Financial charges decreased $11.0 million in 2010 compared to 2009 primarily due to lower effective interest rates and lower average debt outstanding.

Equity income from Great Lakes was $58.7 million in 2010, a decrease of $0.4 million compared to $59.1 million in 2009. The decrease in equity income was primarily due to decreased transmission revenues, partially offset by depreciation rate reductions from the GL Settlement and lower operating expenses. Great Lakes' transmission revenues in 2010 decreased $27.3 million compared to 2009 due to the impact of the GL Settlement rates on long-term revenues and decreased sales of short-term capacity. Operating expenses decreased $7.3 million in 2010 compared to 2009 primarily due to lower maintenance costs.

Net income prior to recast from Other Pipes, which includes results from North Baja and Tuscarora, was $36.9 million in 2010, an increase of $8.9 million compared to 2009. This increase was primarily due to the $8.3 million contribution to net income from North Baja for a full year in 2010 compared to six months in 2009.

Costs at the Partnership level decreased $3.8 million to $25.8 million in 2010 compared to 2009. The decrease was primarily due to costs incurred in 2009 relating to the North Baja acquisition and Incentive Distribution Rights (IDRs) restructuring, along with lower financial charges in 2010 resulting from lower average debt outstanding.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008

Net income decreased $16.9 million to $106.1 million in 2009 compared to $123.0 million in 2008. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast decreased $9.9 million to $97.8 million in 2009 compared to $107.7 million in 2008. This decrease was primarily due to lower equity income from Northern Border, partially offset by the contribution from North Baja since the acquisition. North Baja contributed $11.6 million to the Partnership's net income subsequent to its acquisition on July 1, 2009.

Equity income from Northern Border was $40.3 million in 2009, a decrease of $25.0 million compared to 2008. A portion of this decrease in equity income was due to the Partnership's $8.1 million share of Northern Border's gain recorded on the sale of Bison in 2008. Excluding the gain, Northern Border's 2009 net income decreased $33.9 million compared to 2008 primarily due to decreased transmission revenues, partially offset by lower operating expenses and financial charges. Northern Border's transmission revenues decreased $43.9 million due to reductions in contracted capacity compared to 2008. In 2009, demand for Northern Border's transportation services, and therefore ability to contract capacity, continued to be negatively impacted by increased U.S. natural gas supplies being transported to the Midwestern and Eastern markets from new U.S. supply sources, including the Rockies Basin and southern shale gas, which displaced demand for natural gas from traditional natural gas sources including the WCSB. Reduced overall demand for natural gas related to the economic environment also affected demand for Northern Border's transportation. Operating expenses decreased $7.2 million in 2009 compared to 2008 primarily due to decreased property taxes and lower general and administrative costs. Excluding the gain recorded on the sale of Bison in 2008, financial charges and other decreased $3.5 million in 2009 compared to 2008 primarily due to lower interest rates and average debt outstanding.

Net income from Other Pipes, which includes results from North Baja and Tuscarora, was $36.3 million in 2009, an increase of $6.0 million compared to 2008. Excluding the contribution from North Baja prior to the acquisition, net income from Other Pipes, prior to recast, was $28.0 million, an increase of $13.0 million. This increase was primarily due to the acquisition of North Baja which contributed $11.6 million to net income in 2009, as well as increased transmission revenues from a full year of operation of Tuscarora's Likely compressor station expansion that went into service in April 2008.

Equity income from Great Lakes was $59.1 million in 2009, an increase of $1.8 million compared to $57.3 million in 2008. The increase in equity income was primarily due to increased transmission revenues and decreased operating expenses. Transmission revenues increased primarily due to increased sales of short-term services, partially offset by decreased reservation revenues resulting from re-negotiation of contracts at lower rates and non-renewal of services. Operating expenses decreased primarily due to lower compressor fuel use tax, lower property taxes and lower transition costs. These decreases in operating expenses were offset by increased repairs and overhauls.

Costs at the Partnership level were $29.6 million in 2009, a decrease of $0.3 million compared to 2008. This decrease was primarily due to lower financial charges and other, partially offset by increased operating expenses. The decrease in financial charges and other was a result of lower interest rates, partially offset by higher average debt outstanding and losses on interest rate derivatives. Operating expenses increased primarily due to transaction costs relating to the North Baja acquisition and the concurrent IDR restructuring.

PARTNERSHIP CASH FLOWS

The Partnership uses the non-GAAP financial measures "Partnership cash flows" and "Partnership cash flows before General Partner distributions" as they provide a measure of cash generated during the period to evaluate our cash distribution capability. As well, management uses these measures as a basis for recommendations to our General Partner's board of directors regarding the distribution amount to be declared each quarter. Partnership cash flow information is presented to enhance investors' understanding of the way that management analyzes the Partnership's financial performance.

The Partnership calculates Partnership cash flows as net income, less North Baja's net income contribution prior to acquisition, plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja and Tuscarora, and cash distributions received in excess of equity income from the Partnership's equity investments, Great Lakes and Northern Border, net of distributions declared to the General Partner. Partnership cash flows before General Partner distributions represent Partnership cash flows prior to distributions declared to the General Partner.

Partnership cash flows and Partnership cash flows before General Partner distributions are provided as a supplement to GAAP financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP.

Non-GAAP Measures
Reconciliations of Net Income to Net Income Prior to Recast and Partnership Cash Flows

Year Ended December 31 *(millions of dollars except per common unit amounts)*	**2010**	2009	2008
Net income[(a)]	**137.1**	106.1	123.0
North Baja's contribution prior to acquisition[(a)]	**–**	(8.3)	(15.3)
Net income prior to recast	**137.1**	97.8	107.7
Add:			
Cash distributions from Great Lakes[(b)]	**69.2**	72.5	73.9
Cash distributions from Northern Border[(b)]	**86.0**	75.7	90.7
Cash flows provided by North Baja's operating activities	**29.6**	15.7	–
Cash flows provided by Tuscarora's operating activities	**23.9**	23.7	21.5
	208.7	187.6	186.1
Less:			
Equity income from investment in Great Lakes	**(58.7)**	(59.1)	(57.3)
Equity income from investment in Northern Border	**(67.3)**	(40.3)	(65.3)
North Baja's net income	**(20.7)**	(11.6)	–
Tuscarora's net income	**(16.2)**	(16.4)	(15.0)
	(162.9)	(127.4)	(137.6)
Partnership cash flows before General Partner distributions	**182.9**	158.0	156.2
General Partner distributions[(c)]	**(2.8)**	(7.8)	(12.7)
Partnership cash flows	**180.1**	150.2	143.5
Cash distributions declared	**(139.6)**	(123.6)	(110.8)
Cash distributions declared per common unit[(d)]	**$2.960**	$2.895	$2.815
Cash distributions paid	**(138.7)**	(117.0)	(108.6)
Cash distributions paid per common unit[(d)]	**$2.940**	$2.870	$2.775

(a) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

[b] In accordance with the cash distribution policies of the respective pipeline systems, cash distributions from Great Lakes and Northern Border are based on their respective prior quarter financial results, except that the distribution paid by Northern Border in the third quarter of 2008 included a special distribution of $16.4 million (Partnership share – $8.2 million) related to the sale of Bison.

[c] General Partner distributions represent the cash distributions declared to the General Partner with respect to its two percent interest plus an amount equal to incentive distributions. Prior to 2009, General Partner distributions were based on the cash distributions paid during the quarter to the General Partner. As a result of the retrospective application of *Accounting Standards Codification* 260-10-55, General Partner distributions for the year ended December 31, 2008 increased from $11.8 million to $12.7 million.

[d] 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 percent interest plus an amount equal to incentive distributions.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009

Partnership cash flows increased $29.9 million to $180.1 million in 2010 compared to $150.2 million in 2009. This increase was primarily due to an additional six months of operating cash flows in the amount of $13.9 million from North Baja, which was acquired July 1, 2009, as well as an increase in cash distributions from Northern Border of $10.3 million and a decrease of $5.0 million in General Partner distributions resulting from the IDR restructuring on July 1, 2009. Additionally, Partnership general and administrative costs were lower in 2010 due to costs incurred in 2009 relating to the North Baja acquisition and IDR restructuring. These positive factors were partially offset by decreased cash distributions from Great Lakes of $3.3 million.

The Partnership paid distributions of $138.7 million in 2010, an increase of $21.7 million compared to 2009, due to an increase in the number of common units outstanding and an increase in the distribution of $0.02 per common unit in the third quarter 2010.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008

Partnership cash flows increased $6.7 million to $150.2 million in 2009 compared to $143.5 million in 2008. This increase was primarily due to $15.7 million of cash flows provided by North Baja's operating activities since the Partnership's July 1, 2009 acquisition, a decrease of $4.9 million in General Partner distributions resulting from the IDR restructuring on July 1, 2009 and an increase of cash flows provided by Tuscarora's operating activities of $2.2 million. These positive factors were partially offset by decreased cash distributions from Northern Border of $15.0 million. Northern Border's decreased cash distributions were due to a special one-time $8.2 million distribution for the proceeds received in connection with the sale of Bison in 2008 and lower net income in 2009 as compared to 2008, partially offset by a reduction in maintenance capital expenditures.

The Partnership paid distributions of $117.0 million in 2009, an increase of $8.4 million compared to 2008 due to an increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts.

Other Cash Flows

In 2010, North Baja and Tuscarora made capital expenditures of $9.3 million, of which the majority was spent on the acquisition of the Yuma Lateral expansion facilities and contracts in place on March 5, 2010, for a purchase price of $7.6 million. The Yuma Lateral was placed into service on March 13, 2010. Also in 2010, the Partnership made an equity contribution of $9.3 million to Great Lakes of which $4.7 million was used by Great Lakes to fund debt repayments and $4.6 million was used by Great Lakes to fund capital expenditures.

On July 1, 2009, the Partnership acquired North Baja with proceeds from equity issuances of $80.0 million, including the General Partner's contribution to maintain its two percent interest, a $170.0 million draw on its revolving credit facility and cash on hand. In 2009, the Partnership made equity contributions to Northern Border totaling $42.3 million to partially fund the repayment of Northern Border's $200.0 million of debt which matured on September 1, 2009 and to complete the Des Plaines Project. In the fourth quarter of 2009, net proceeds from equity issuances of $185.5 million, including the General Partner's contribution to maintain its two percent interest, were used to repay long-term debt outstanding on the Partnership's revolving portion of its senior credit facility.

In 2008, Tuscarora made capital expenditures of $6.8 million that related primarily to the Likely compressor station expansion.

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 flows from North Baja and Tuscarora and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

Summary of the Partnership's Contractual Obligations

The Partnership's contractual obligations as at December 31, 2010 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Senior Credit Facility due 2011	483.0	483.0	–	–	–
6.89% Series C Senior Notes due 2012	3.9	0.8	3.1	–	–
3.82% Series D Senior Notes due 2017	27.0	–	7.1	11.2	12.3
Interest payments on Senior Credit Facility[(a)]	16.7	16.7	–	–	–
Interest payments on Senior Notes	6.1	1.3	3.2	2.3	0.3
Fair value of derivative contracts[(b)]	13.8	13.8	–	–	–
Operating leases	3.9	0.2	0.5	0.4	3.0
	554.4	515.8	13.9	13.9	15.6

(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 year ended December 31, 2010 of 0.91 percent 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, 2010.

Yuma Lateral

The North Baja Acquisition Agreement provided that the Partnership make an additional payment of up to $2.4 million to TransCanada in the event that any other shippers contracted for services on the Yuma Lateral before June 30, 2010. A potential shipper signed a precedent agreement with North Baja on June 29, 2010 to enter into agreements for service on the Yuma Lateral. Accordingly, an amendment to the Acquisition Agreement between the Partnership and TransCanada was entered into on June 29, 2010 to allow TransCanada to continue to pursue additional contracts until December 31, 2010. On July 28, 2010, TransCanada secured additional contracts and, as a result, an additional payment of up to $2.4 million will be paid to TransCanada when the facilities associated with the additional contracts go into service which is anticipated in first quarter 2011.

The Partnership's Debt and Credit Facilities

The Partnership's Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility with a banking syndicate. At December 31, 2010, $475.0 million remained outstanding under the senior term loan (2009 – $475.0 million) and $8.0 million was outstanding under the senior revolving credit facility (2009 – $9.0 million), leaving $242.0 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. However, once a senior term loan is repaid, it cannot be re-borrowed. Borrowings under the Senior Credit Facility 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 $483.0 million outstanding under the Senior Credit Facility at December 31, 2010 (2009 – $484.0 million). The interest rate on the Senior Credit Facility averaged 0.91 percent for the year ended December 31, 2010 (2009 – 1.42 percent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.30 percent for the year ended December 31, 2010 (2009 – 4.10 percent). Prior to hedging activities, the interest rate was 0.83 percent at December 31, 2010 (2009 – 0.97 percent). The Partnership expects to renew its Senior Credit Facility in 2011 at market rates.

The Senior Credit Facility requires the Partnership to maintain a leverage ratio (debt to adjusted cash flow (net income plus cash distributions received, extraordinary losses, interest expense, expense for taxes paid or accrued, depreciation and amortization less equity earnings and extraordinary gains)) of no 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, 2010, 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.

On April 22, 2010, the Partnership filed an automatic universal shelf registration statement on Form S-3 (ASR) with the SEC, which replaced an existing shelf registration statement. The ASR allows the Partnership to issue an indeterminate amount of securities of the Partnership, including both senior and subordinated debt securities and/or common units representing limited partnership interests in the Partnership. The ASR expires April 22, 2013.

On December 21, 2010, Tuscarora's Series A and B Senior Notes matured. Also on December 21, 2010, Tuscarora issued $27.0 million of 3.82 percent Series D Senior Notes, which require principal and interest payments over approximately seven years. The Series D Senior Notes mature on August 21, 2017. Series C and D 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 fair value of the Partnership's long-term debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates. The estimated fair value of the Partnership's long-term debt at December 31, 2010 was $513.9 million (2009 – $544.7 million). As at February 25, 2011, the Partnership had no outstanding borrowings under the $250.0 million revolving portion of the Senior Credit Facility, which expires on December 12, 2011.

Interest Rate Swaps and Options

The Partnership's 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 $375.0 million at December 31, 2010 (2009 – $375.0 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 percent. $75.0 million of variable-rate debt is hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid is 3.86 percent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

Financial instruments are recorded at fair value on a recurring basis and are categorized into one of three categories based upon a fair value hierarchy. The Partnership has classified all of its derivative financial instruments as Level II for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At December 31, 2010, the fair value of the interest rate swaps accounted for as hedges was negative $13.8 million (2009 – negative $23.8 million), of which $13.8 million is classified as a current liability (2009 – $12.9 million). The fair value of the interest rate swaps was calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate in the future as interest rates change. In 2010, the Partnership recorded interest expense of $16.5 million on the interest rate swaps and options (2009 – $15.1 million; 2008 – $6.9 million).

Capital Requirements

The Partnership made an equity contribution of $4.6 million to Great Lakes in 2010. This amount represents the Partnership's 46.45 percent share of a $10.0 million cash call issued by Great Lakes to expand backhaul capacity from St. Clair, Michigan to Emerson, Manitoba, Canada. The Partnership also made an equity contribution of $4.7 million to Great Lakes in 2010, which represents the Partnership's 46.45 percent share of a $10.0 million cash call from Great Lakes to make a scheduled debt repayment and is the result of a change in Great Lakes' distribution policy in 2010, whereby Great Lakes commenced funding its debt repayments with cash calls to its partners and making distributions to its partners before deducting amounts for debt repayments. The Partnership is expected to make equity contributions totaling $8.8 million to Great Lakes in 2011 for scheduled debt repayments.

Northern Border's distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by its management committee to establish the timing and amount of required equity contributions. In accordance with this policy, Northern Border did not require any contributions from its partners in 2010. In the third quarter of 2009, Northern Border required an equity contribution of $76.0 million, of which the Partnership's share was $38.0 million, to partially fund the repayment of $200.0 million of debt which matured on September 1, 2009. The Partnership financed this equity contribution with a combination of debt and operating cash flows. In the first quarter of 2009, the Partnership made an equity contribution of $4.3 million to Northern Border, representing the Partnership's 50 percent share of an $8.6 million cash call issued by Northern Border to complete the Des Plaines Project. The Partnership expects to make a required equity contribution of $54 million to Northern Border in 2011 in accordance with Northern Border's distribution policy and an equity contribution of approximately $4.5 million to fund capital expenditures related to the Princeton Lateral Project.

Cash Distribution Policy of the Partnership

The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our General Partner based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its two percent general partner interest and IDRs, and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The distribution to the General Partner illustrated below, other than in its capacity as a holder of 5,797,106 common units that are in excess of its aggregate two percent general partner interest, represents the IDRs.

		Marginal Percentage Interest in Distribution	
	Total Quarterly Distribution per Unit Target Amount	Common Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98%	2%
First Target Distribution	above $0.45 up to $0.81	98%	2%
Second Target Distribution	above $0.81 up to $0.88	85%	15%
Thereafter	above $0.88	75%	25%

On July 1, 2009, in conjunction with the North Baja acquisition, the Partnership amended the IDRs held by the General Partner to eliminate the 50 percent distribution threshold and replaced it with a new maximum distribution threshold of 25 percent (for combined general partner interest and incentive distribution interest).

2010 Fourth Quarter Cash Distribution

On January 18, 2011, the board of directors of our General Partner declared the Partnership's fourth quarter 2010 cash distribution in the amount of $0.75 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2011 to unitholders of record as of January 31, 2011, totaled $35.4 million and was paid in the following manner: $34.7 million to common unitholders (including $4.3 million to the General Partner as holder of 5,797,106 common units and $8.5 million to TransCanada as holder of 11,287,725 common units) and $0.7 million to the General Partner in respect of its two percent general partner interest. The fourth quarter 2010 cash distribution amount represents an annualized cash distribution of $3.00 per common unit.

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 have historically funded operating expenses, debt service and cash distributions to partners primarily with operating cash flow. However, in fourth quarter 2010, Great Lakes started funding its debt repayments with cash calls to its partners.

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 general market conditions.

We believe that our pipeline systems' 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.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations related to debt as at December 31, 2010 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
8.74% series Senior Notes due 2011	10.0	10.0	–	–	–
6.73% series Senior Notes due 2011 to 2018	72.0	9.0	27.0	27.0	18.0
9.09% series Senior Notes due 2012 to 2021	100.0	–	30.0	30.0	50.0
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	291.5	29.9	80.7	71.7	134.6
	683.5	48.9	137.7	128.7	412.6

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 $211.0 million of Great Lakes' partners' capital was restricted as to distributions as at December 31, 2010 (2009 – $221.0 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2010.

The aggregate estimated fair value of Great Lakes' long-term debt was $518.2 million for 2010 (2009 – $506.2 million). The aggregate annual required repayment of senior notes is $19.0 million for each year 2011 through 2015. In 2010, interest expense related to Great Lakes' senior notes was $31.4 million (2009 – $32.9 million; 2008 – $34.2 million).

Other

Great Lakes has 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 at December 31, 2010, included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
6.24% Senior Notes due 2016	100.0	–	–	–	100.0
7.50% Senior Notes due 2021	250.0	–	–	–	250.0
$250 million Credit Agreement due 2012	191.0	–	191.0	–	–
Interest payments on debt	243.0	26.0	75.3	72.9	93.8
Operating leases	64.9	1.9	5.7	6.0	53.2
Other long-term obligations	1.1	1.1	–	–	–
	850.0	29.0	272.0	78.9	497.0

Interest Payments on Credit Agreement

The interest rate at December 31, 2010 of 0.54 percent was used to calculate the interest payments on the Credit Agreement. The interest payment calculation 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 ending in 2011 under a transition services agreement between ONEOK Partners GP, LLC (ONEOK Partners GP) and TransCanada, related to the reimbursement for shared assets acquired by ONEOK Partners to support the operations of Northern Border.

In connection with the Princeton Lateral Project, Northern Border has commitments of $0.3 million at December 31, 2010.

Credit Agreement

Northern Border has a $250.0 million revolving Credit Agreement with certain financial institutions. The Credit Agreement can 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, 2010, $191.0 million was outstanding (2009 – $215.0 million) leaving $59.0 million available for future borrowings. 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 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 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.

Northern Border's long-term debt arrangements contain covenants that restrict the incurrence of secured indebtedness or liens upon property by Northern Border. Under the Credit Agreement, Northern Border is required to comply with certain financial, operational and legal covenants. Among other things, Northern Border is required to maintain a 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 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, 2010, 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. The average interest rate on Northern Border's Credit Agreement at December 31, 2010 was 0.54 percent (2009 – 0.52 percent).

Interest Rate Collar Agreement

In 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 through October 30, 2009 to a range between a floor of 4.35 percent and a cap of 5.36 percent. Northern Border designated the Collar Agreement as a cash flow hedge. At December 31, 2009, Northern Border's balance sheet reflected no unrealized loss and no change in its accumulated other comprehensive loss related to the changes in fair value of the Collar Agreement since inception. In 2009, Northern Border recorded interest expense of $3.8 million under the Collar Agreement (2008 – $1.7 million). The hedge was effective for the years ended December 31, 2009 and 2008; therefore, it had no impact on income due to hedge ineffectiveness.

Long-Term Financing – Debt Securities

Northern Border periodically issues long-term debt securities to meet its capital resource requirements. All of Northern Border's outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums. The indentures of the notes do not limit the amount of unsecured debt Northern Border may incur, but do restrict secured indebtedness.

Under the $100.0 million of 6.24 percent Senior Notes, Northern Border may not at any time permit debt secured by liens to exceed 20 percent of partners' capital and may not permit total debt, at any time, to exceed 70 percent of total capitalization. At December 31, 2010, Northern Border was in compliance with all of its financial covenants.

Northern Border's Senior Notes issuances of $100.0 million due in 2016 and $250.0 million due in 2021 are borrowed at fixed interest rates of 6.24 percent and 7.50 percent, respectively. Northern Border intends to maintain the current schedule of maturities, which will result in no gains or losses on their respective repayments. At December 31, 2010, the aggregate fair value of the outstanding senior notes was approximately $599.0 million (2009 – $397.0 million). In 2010, interest expense related to the senior notes was $25.0 million (2009 – $31.3 million; 2008 – $34.3 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 their respective management committee.

Great Lakes' distribution policy is to distribute 100 percent of distributable cash flow based generally on earnings before current income taxes and depreciation less capacity 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. In fourth quarter 2010, Great Lakes changed their distribution policy. Previous to fourth quarter 2010, distributable cash flows included deductions for debt repayments. Great Lakes will now, at the option of its partners, fund its debt repayments with equity contributions from its partners.

Northern Border's distribution policy is to distribute 100 percent of the distributable cash flow based on earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures and adopted certain changes related to equity contributions. The changes defined minimum equity to total capitalization ratios to be used by the Northern Border management committee to determine the amount of required equity contributions, timing of the required contributions, and for any shortfall due to the inability to refinance maturing debt to be funded by equity contributions.

On February 1, 2011, a cash distribution of $36.3 million was declared and paid by Great Lakes for the fourth quarter of 2010, of which the Partnership's 46.45 percent share was $16.9 million. On February 1, 2011, a cash distribution of $51.5 million was declared and paid by Northern Border for the fourth quarter of 2010, of which the Partnership's 50 percent share was $25.8 million.

Investing Activities for our Pipeline Systems

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

Year Ended December 31 *(millions of dollars)*	**2010**	2009	2008
Great Lakes:			
Maintenance	**8.0**	5.9	12.3
Growth	**6.0**	2.6	–
Great Lakes' capital spending	**14.0**	8.5	12.3
Northern Border:			
Maintenance	**5.4**	6.7	8.4
Growth	**4.5**	4.4	12.1
Northern Border's capital spending	**9.9**	11.1	20.5
North Baja:			
Maintenance	**0.2**	0.3	12.8
Growth	**8.9**	0.8	15.0
North Baja's capital spending	**9.1**	1.1	27.8
Tuscarora:			
Maintenance	**0.2**	0.2	0.1
Growth	**–**	0.6	6.7
Tuscarora's capital spending	**0.2**	0.8	6.8

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

Great Lakes incurred $6.0 million and $2.6 million in growth capital expenditures in 2010 and 2009, respectively, primarily related to an expansion project involving upgrades to facilities to increase system capabilities to provide firm transportation services from St. Clair, Michigan to Emerson, Manitoba, Canada. The remaining expenditures of Great Lakes in 2010 through 2008 of $8.0 million, $5.9 million and $12.3 million, respectively, were comprised of maintenance capital projects including compressor engine overhauls and pipeline integrity program costs. In 2011, Great Lakes expects to invest approximately $14.1 million for maintenance capital expenditures, of which the Partnership's share is $6.5 million. No significant growth capital expenditures are planned for 2011.

Northern Border incurred growth capital expenditures of $4.5 million in 2010 primarily related to the Princeton Lateral Project, while growth expenditures of $4.4 million in 2009 and $12.1 million in 2008 were primarily related to spending for the Des Plaines Project. The maintenance capital expenditures of Northern Border in 2010 through 2008 of $5.4 million, $6.7 million and $8.4 million, respectively, are comprised of maintenance capital projects including compressor engine overhauls. In 2011, Northern Border Pipeline expects to spend approximately $28.9 million for capital expenditures, of which the Partnership's share is $14.5 million. The Partnership's share of maintenance capital expenditures are estimated at $7.1 million and include renewals and replacements of existing facilities. In 2011, Northern Border expects to spend approximately $14.5 million for growth capital expenditures related to the Princeton Lateral Project, of which the Partnership expects to contribute $4.5 million.

In 2010, North Baja incurred $9.1 million of capital expenditures primarily related to the Yuma Lateral Project and routine pipeline maintenance and integrity costs. In 2009, North Baja capital expenditures of $1.1 related to minor growth projects. In 2011, North Baja expects to spend approximately $0.3 million for capital expenditures, primarily related to pipe integrity program costs and system pipeline improvements. Excluding an additional payment of up to $2.4 million for the Yuma Lateral, no significant growth capital expenditures are planned for 2011.

In 2010, Tuscarora incurred $0.2 million of capital expenditures primarily related to the replacement of meter station regulators and batteries. Tuscarora's 2009 and 2008 capital expenditures of $0.8 million and $6.8 million, respectively, related to the replacement of electric system components at various compressor stations and to the Likely compressor station expansion. In 2011, Tuscarora expects to spend approximately $0.6 million for maintenance capital expenditures, primarily related to pipe integrity program costs and system pipeline improvements. No significant growth capital expenditures are planned for 2011.

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 account for our investments in North Baja and Tuscarora using the consolidation method, as we wholly-own both entities.

Regulation

Our pipeline systems' accounting policies conform to *Accounting Standards Codification (ASC) 980 – Regulated Operations*. Our pipeline systems consider several factors to evaluate their continued application of the provisions of ASC 980 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 ASC 980 or other regulatory actions, Northern Border would be required to write off the regulatory assets at that time. As at December 31, 2010, Northern Border reflected regulatory assets of $20.3 million on its balance sheet (2009 – $20.1 million). These assets are being amortized as directed by the FERC in Northern Border's previous regulatory proceedings over varying remaining time periods up to 40 years.

As at December 31, 2010, Tuscarora has no regulatory assets (2009 – nil) and $0.5 million in regulatory liabilities (2009 – nil).

As at December 31, 2010 and 2009, Great Lakes and North Baja 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 *ASC 450 – 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 and cash flow.

Impairment of Long-Lived Assets and Goodwill

We assess our long-lived assets for impairment based on *ASC 360-10-35 Property, Plant, and Equipment – Overall – Subsequent Measurement* whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets. 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 annually, based on *ASC 350 – Intangibles – Goodwill and Other*, or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with ASC 350, to the book value of each operation. If the fair value is less than 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 the calculated implied fair value of the goodwill, an impairment charge is recorded. At December 31, 2010 and 2009, we had $130.2 million of goodwill recorded on our balance sheet related to the North Baja and Tuscarora acquisitions. No impairment of goodwill existed at December 31, 2010.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- discount rates;
- market supply and demand assumptions;
- growth opportunities;

- competition from other pipelines; and
- regulatory changes.

Significant changes in these assumptions could affect our need to record an impairment charge.

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. Please read Item 3. "Legal Proceedings" for additional information.

Environmental

We believe that our pipeline systems are in substantial compliance with applicable environmental laws and regulations. Please read Item 1. "Business" for additional information.

RELATED PARTY TRANSACTIONS

Please read Item 13. "Certain Relationships and Related Transactions, and Director Independence" for information regarding related party transactions.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

The Partnership and our pipeline systems are also exposed to other risks such as interest rate risk, credit risk, liquidity risk and foreign exchange fluctuations. Our exposure to market risk discussed below includes forward-looking statements and is not necessarily indicative of actual results, which may not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual market conditions.

Market risk is the risk of loss arising from adverse changes in market rates. 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.

We record derivative financial instruments on the balance sheet as assets and liabilities at fair value. We estimate the fair value of derivative financial instruments using available market information and appropriate valuation techniques. Changes in the fair value of derivative financial instruments are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. Qualifying derivative 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.

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 within established policies and procedures. 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 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.

Our interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at December 31, 2010 (2009 – $375.0 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 percent. $75.0 million of variable-rate debt is hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid is 3.86 percent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

At December 31, 2010, the fair value of the interest rate swaps accounted for as hedges was negative $13.8 million (2009 – negative $23.8 million), of which $13.8 million is classified as a current liability (2009 – $12.9 million). The fair value of the interest rate swaps was calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. In 2010, the Partnership recorded interest expense of $16.5 million on the interest rate swaps and options (2009 – $15.1 million; 2008 – $6.9 million).

At December 31, 2010, we had $483.0 million (2009 – $484.0 million) outstanding on our Senior Credit Facility. Utilizing the conditions of the interest rate swaps, if LIBOR interest rates hypothetically increased by one percent (100 basis points) compared to the rates in effect at December 31, 2010, our annual interest expense would have increased and our net income would have decreased by $1.1 million; and if LIBOR interest rates hypothetically decreased to zero percent compared to the rates in effect at December 31, 2010, our annual interest expense would have decreased and our net income would have increased by $0.3 million. These amounts have been determined by considering the impact of the hypothetical interest rates on unhedged debt outstanding as at December 31, 2010.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its revolving 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 at December 31, 2010, 65 percent of Northern Border's outstanding debt was at fixed rates (2009 – 62 percent).

Standard & Poor's (S&P) issued a report on July 20, 2010 affirming Northern Border's issuer credit rating at "A –" but revised the outlook to "negative" from "stable." The negative outlook was based on declining credit metrics, which S&P believes are largely due to declining cash flows from Northern Border's firm transportation contracts. S&P will consider revising the outlook to "stable" if Northern Border is successful in recontracting capacity such that cash flows improve for a sustained period, or S&P may lower the rating if credit metrics remain weak, which would cause Northern Border's interest costs to increase.

If interest rates hypothetically increased by one percent (100 basis points) compared with rates in effect at December 31, 2010, Northern Border's annual interest expense would increase and its net income would decrease by approximately $1.9 million; and if interest rates hypothetically decreased to zero percent compared with rates in effect at December 31, 2010, Northern Border's annual interest expense would decrease and its net income would increase by approximately $0.5 million.

Great Lakes and Tuscarora utilize fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates. Interest rate risk does not apply to North Baja, as it currently does not have any debt.

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 with respect to transported natural gas volumes.

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 consists 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, 2010, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $7.6 million (2009 – $7.4 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. Due to the deterioration of global financial markets in 2008 and 2009, we continue 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 become 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, 2010, the Partnership had a committed revolving bank line of $250.0 million maturing in December 2011. As at December 31, 2010, the outstanding balance on this facility was $8.0 million. In addition, at December 31, 2010, Northern Border had a committed revolving bank line of $250.0 million maturing in April 2012. As at December 31, 2010, $191.0 million was drawn on this facility.

The Partnership does not have any material foreign exchange risks.

Item 8. Financial Statements and Supplementary Data

The financial statements required by this item are included in Part IV, Item 15 of this report on page F-1.

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

None.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15(e) under the Exchange Act, the management of our General Partner, including the principal executive officer and principal financial officer, evaluated as of the end of the period covered by this report the effectiveness of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. The Partnership's disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon and as of the date of the evaluation, the management of our General Partner, including the principal executive officer and principal financial officer, concluded that the Partnership's disclosure controls and procedures as of the end of the year covered by this annual report were effective to provide reasonable assurance 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, as amended (the "Exchange Act"), is (a) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (b) accumulated and communicated to the management of our General Partner, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2010, there was 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 principal 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 at December 31, 2010 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. 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

The Partnership 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 the Partnership. Each director holds office for a one-year term or until his or her successor is earlier appointed. All officers of the General Partner serve at the discretion of the board of directors of the General Partner which is a wholly-owned subsidiary of TransCanada.

Name	Age	Position with General Partner
Gregory A. Lohnes	54	Chairman and Director
Steven D. Becker	60	President, Principal Executive Officer and Director
Jack F. Jenkins-Stark	60	Independent Director
David L. Marshall	71	Independent Director
Walentin (Val) Mirosh	65	Independent Director
James M. Baggs	49	Director
Kristine L. Delkus	53	Director
Stuart P. Kampel	42	Vice-President, Business Development
Stephanie E. Wilson	43	Vice-President, Commercial
Terry C. Ofremchuk	60	Vice-President, Taxation
Rhonda L. Amundson	49	Treasurer
Donald J. DeGrandis	62	Secretary
Robert C. Jacobucci	42	Controller, Principal Financial Officer

Mr. Lohnes was appointed a director of the General Partner in January 2007 and has served as Chairman of the General Partner's board of directors since March 2010. Mr. Lohnes' principal occupation is President, Natural Gas Pipelines of TransCanada, a position he has held since July 2010. Prior to July 2010, he was Executive Vice-President and Chief Financial Officer of TransCanada, a position he held since June 2006. Prior to June 2006, he was President and Chief Executive Officer of Great Lakes Gas Transmission Company. Mr. Lohnes has extensive senior management experience in the oil and gas industry as a result of his service as an executive officer for TransCanada and its subsidiaries. His day-to-day leadership as President, Natural Gas Pipelines of TransCanada and his prior roles as Chief Financial Officer of the Partnership, Executive Vice-President and Chief Financial Officer of TransCanada and President and Chief Executive Officer of Great Lakes provide him with an intimate knowledge of the Partnership, including its strategies, operations, markets and financing requirements. Mr. Lohnes' business judgment, management experience and leadership skills are highly valuable in assessing our business strategies and accompanying risks.

Mr. Becker was appointed President of the General Partner in August 2010 and serves as the General Partner's principal executive officer. Mr. Becker also serves as a director of the General Partner, a position he has held since January 2007. Mr. Becker's principal occupation is Vice-President, Business Development, Natural Gas Pipelines of TransCanada, a position he has held since August 2010. Mr. Becker was Vice-President, Pipeline Development for TransCanada from June 2006 to August 2010. From April 2003 to June 2006, he was Vice-President, Gas Development of TransCanada. As the President of the General Partner and Vice-President, Business Development, Natural Gas Pipelines for TransCanada, Mr. Becker has intimate knowledge of the Partnership's pipeline operations, as well as a unique understanding of market factors and operational challenges and opportunities. Mr. Becker brings extensive project development and operational experience to the board and his extensive experience in the natural gas industry enhances the knowledge of the board in these areas of the industry. From his prior roles in finance, natural gas marketing, strategy and business development at TransCanada, Mr. Becker's breadth of executive experiences are applicable to many of the matters routinely facing the Partnership, which assists the board in creating and executing the Partnership's strategic plan.

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 May 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 banking and private equity services) from April 2004 to May 2007. Through his current and prior roles as chief financial officer of numerous companies, Mr. Jenkins-Stark brings valuable financial expertise and management experience, including extensive knowledge regarding financial operations, investor relations, energy risk management, regulatory affairs and knowledge of the natural gas industry. Mr. Jenkin-Stark's prior service on the audit committee of the board of directors of another company further enhances his qualifications to serve as a member of our board. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis.

Mr. Marshall was appointed a director of the General Partner in July 1999. Mr. Marshall retired as Chief Financial officer of The Pittston Company in 1995 and served as Vice Chairman of that company from 1995 to 1998. Mr. Marshall is a corporate director. As a former chief executive officer and chief financial officer at other public companies, Mr. Marshall has valuable experience with many functions pertinent to our board, including financing, strategic and operational matters and the evaluation of acquisition opportunities. Mr. Marshall contributes extensive financial acumen and an understanding of the oil and gas services industry due to his prior experiences as a chief financial officer and director and audit committee chairman of other public companies. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis.

Mr. Mirosh was appointed a director of the General Partner in September 2004. Mr. Mirosh's principal occupation is President of Mircan Resources Ltd., a private consulting company, a position he has held since 2009. From April 2008 to December 2009, he was Vice-President and Special Advisor to the President and Chief Operating Officer of NOVA Chemicals Corporation (a commodity chemicals and plastics company). From July 2003 to April 2008, Mr. Mirosh was President of Olefins and Feedstocks, a division of NOVA Chemicals Corporation. Mr. Mirosh is also a director of Superior Plus Income Fund. Mr. Mirosh's extensive experience in the natural gas transmission sector enhances the knowledge of the board in this area of the industry. As a current and former executive and director of various companies, his breadth of experience is applicable to many of the matters routinely facing the Partnership, including making valuable contributions to our audit committee. Moreover, Mr. Mirosh's experience and industry knowledge, complemented by an engineering and legal educational background, enable Mr. Mirosh to provide the board with executive counsel on a full range of business, financial, technical and professional matters.

Mr. Baggs was appointed a director of the General Partner in March 2010. Mr. Baggs' principal occupation is Vice-President, Operations and Engineering for TransCanada, a position he has held since 2008. From 2006 to 2008, Mr. Baggs was Vice-President, Field Operations and Engineering for TransCanada. He has been with TransCanada for 21 years. In his position as Vice-President, Operations and Engineering at TransCanada, Mr. Baggs has unique insight into our operational challenges and opportunities. With a nearly 30-year career focused on providing construction, design, operations, maintenance and commissioning experience in various industries, Mr. Baggs contributes a broad-based understanding of the oil and gas industry and of complex operational and safety matters. Mr. Baggs' service on the board of directors of other energy services companies further enhances his qualifications to serve as a member of our board.

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. As Deputy General Counsel, Pipelines and Regulatory Affairs, Ms. Delkus is responsible for, and has intimate knowledge of, the legal aspects of all regulatory and commercial matters for TransCanada's pipeline business in Canada and the U.S. Ms. Delkus' experience and industry knowledge, complemented by an extensive legal career, enable her to provide the board with executive counsel on the full range of business, regulatory, legal and professional matters.

In October 2010, Mr. Kampel was appointed Vice-President, Business Development for the General Partner. Mr. Kampel's principal occupation is Director, Business Development at TransCanada, a position he has held since December 2003. Since 2004, he has been responsible for identifying and pursuing natural gas pipeline and other related energy investment opportunities in Mexico.

In October 2010, Ms. Wilson was appointed Vice-President, Commercial for the General Partner. Ms. Wilson's principal occupation is Director, Commercial Affiliated Pipeline, a role she has held since 2009 and which includes her work as General Manager of the TransQuébec and Maritimes Pipeline for TransCanada. From 2007 to 2009, Ms. Wilson was Director of Project and Risk Management Systems for TransCanada, and from 2006 to 2007, she was Manager of TransCanada's Cartier Energy Wind Power Projects. From 2003 to 2006, Ms. Wilson held the position of Assistant Project Manager of TransCanada's Becancour Cogeneration Power Project.

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, a position he has held since 1997.

Ms. Amundson was appointed Treasurer of the General Partner in December 2008. Ms. Amundson's principal occupation is Manager, Capital Markets of TransCanada, a position she has held since 2005.

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, Mr. DeGrandis was Associate General Counsel, Corporate Secretarial of TransCanada.

Mr. Jacobucci was appointed principal financial officer of the General Partner and Controller of the General Partner in November 2009. His principal occupation is Director of Pipeline Accounting for TransCanada. From November 2008 to November 2009, Mr. Jacobucci was Director, Energy Accounting of TransCanada. From February 2006 to November 2008, Mr. Jacobucci was Manager, Power Accounting and Manager, U.S. Pipeline Accounting.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the General Partner 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 the Partnership.

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

The Partnership 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 the Partnership's 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 the Partnership's audit report, that the committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and for the committee to be responsible for establishing procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters, including procedures for the confidential, anonymous submission by employees of the General Partner concerns regarding questionable accounting or auditing matters. The committee has adopted TransCanada's Ethics Help-Line in fulfillment of its responsibility to establish a confidential and anonymous whistle blowing process. The toll free Ethics Help-Line number and the audit committee's charter are published on the Partnership's website at www.tcpipelineslp.com.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, as amended, requires the Partnership's directors and executive officers, and persons who beneficially own more than ten percent of the common units, to file reports of ownership and changes in ownership with the SEC and to furnish us with copies of all such reports. Based solely upon a review of the copies of the reports received by us, we believe that all such filing requirements were satisfied during 2010, with the exception of one late filing on Form 5 in February 2011 relating to a charitable gift by Mr. Jack Jenkins-Stark in November 2010.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership, and we are managed by the executive officers of our General Partner. We do not directly employ any of the individuals responsible for managing or operating our business. 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, and Director Independence" for more information regarding this arrangement.

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

The following table summarizes the salary allocated to and paid by us in 2010, 2009 and 2008 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 his or her salary.

Summary Compensation Table

		Base Salary Allocated to the Partnership		
Name and Principal Position	Year	Canadian Dollars	US Dollar Equivalent	Total[(a)]
Steven D. Becker	**2010**	**29,277**	**29,424**	**29,424**
President and Principal Executive Officer	2009	–	–	–
	2008	–	–	–
Russell K. Girling	**2010**	**14,795**	**14,869**	**14,869**
Former Chief Executive Officer	2009	75,001	71,663	71,663
	2008	68,251	55,733	55,733
Mark A.P. Zimmerman	**2010**	**44,195**	**44,416**	**44,416**
Former President	2009	110,004	105,109	105,109
	2008	108,753	88,808	88,808
Robert C. Jacobucci	**2010**	**26,920**	**27,054**	**27,054**
Controller and Principal Financial Officer	2009	3,610	3,450	3,450
	2008	–	–	–

(a) The compensation of executive officers of the General Partner is paid by TransCanada in Canadian dollars. The US dollar equivalents have been calculated using the applicable December 31, 2010 noon buying rate of 1.005 as reported by the Bank of Canada (2009 – 0.9555; 2008 – 0.8166).

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 0.30 for benefits in 2010 (2009 – factor of 0.32; 2008 – factor of 0.35) and a factor of 0.49 for incentive compensation in 2010 (2009 – factor of 0.48; 2008 – factor of 0.40). The total amount reimbursed for benefits and incentive compensation was $766,564 in 2010 for all employees providing services to the Partnership, including the named officers in the above table (2009 – $667,059; 2008 – $610,801).

Compensation Committee Report

Neither we, nor our General Partner, have 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:
Steven D. Becker
Jack F. Jenkins-Stark
David L. Marshall
Walentin Mirosh
Gregory A. Lohnes
Kristine L. Delkus
James M. Baggs

Independent Director Compensation

Independent Director Compensation[(a)] For the year ended December 31, 2010 *(in dollars)*	Earned or Paid in Cash[(b)]	Unit Awards[(c)]	All Other Compensation[(d)]	Total
David L. Marshall[(e)]	53,500	30,000	7,622	91,122
Jack F. Jenkins-Stark[(f)]	54,000	30,000	14,467	98,467
Walentin (Val) Mirosh	49,500	30,000	7,622	87,122

(a) 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, James M. Baggs 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.

(b) Pursuant to the Deferred Share Unit Plan for Non-Employee Directors, Jack F. Jenkins-Stark elected to receive half of his fees ($27,000) in Deferred Share Units. Due to this election, 620 Deferred Share Units were credited to Mr. Jenkins-Stark's account in 2010, all of which were outstanding at December 31, 2010.

(c) Amounts presented reflect the compensation expense recognized related to the Deferred Share Units granted during 2010 under the Deferred Share Unit Plan for Non-Employee Directors. On January 19, 2010, each independent director was granted 791 Deferred Share Units, all of which were outstanding at December 31, 2010. At December 31, 2010, David L. Marshall, Jack F. Jenkins-Stark and Walentin (Val) Mirosh held 2,990, 6,067 and 2,990 Deferred Share Units, respectively. The fair value of Deferred Share Units held by Mr. Marshall, Mr. Jenkins-Stark and Mr. Mirosh at December 31, 2010 was $110,638, $224,499 and $110,638, respectively.

(d) 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 206 Deferred Share Units in 2010, while Jack F. Jenkins-Stark was credited 391 Deferred Share Units. All Deferred Share Units credited during 2010 were outstanding at December 31, 2010.

(e) Chairman of the Audit Committee

(f) Lead Director and Chairman of the Conflicts Committee

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 $60,000 per annum, of which $30,000 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). On October 20, 2010, the board approved an increase in the annual retainer fee of $4,000 per annum, of which $2,000 is granted in Deferred Share Units, resulting in a retainer fee of $64,000 per annum, of which $32,000 is automatically granted in Deferred Share Units, effective January 1, 2011.

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 2010, as part of the retainer fee, each independent director received an annual grant of Deferred Share Units with a value of $30,000.

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 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. Deferred Share Units redeemed for common units would be purchased by the Partnership in the open market.

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 at February 22, 2011 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 percent 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 percent of the voting securities of the Partnership.

	Amount and Nature of Beneficial Ownership		
Name and Business Address	Number of Common Units[a]	Number of DSUs[b]	Percent of Class[c]
TransCan Northern Ltd.[d] 450 1st Street SW Calgary, Alberta T2P 5H1	11,287,725	–	24.4
TC Pipelines GP, Inc.[e] 450 1st Street SW Calgary, Alberta T2P 5H1	5,797,106	–	12.5
Tortoise Capital Advisors, L.L.C.[f] 11550 Ash Street, Suite 300 Leawood, Kansas 66211	3,428,859	–	7.4
David L. Marshall 2880 Oxley Drive Sparks, Nevada 89436	–	3,643	*
Walentin (Val) Mirosh 18 Elmont Place S.W. Calgary, Alberta T3H 0K5	–	3,643	*

Name and Business Address	Number of Common Units[a]	Number of DSUs[b]	Percent of Class[c]
	Amount and Nature of Beneficial Ownership		
Jack F. Jenkins-Stark[g] 1999 Harrison Street, Suite 2150 Oakland, California 94612	4,888	6,764	*
Gregory A. Lohnes 450 1st Street SW Calgary, Alberta T2P 5H1	–	–	–
Steven D. Becker 450 1st Street SW Calgary, Alberta T2P 5H1	–	–	–
Kristine L. Delkus 450 1st Street SW Calgary, Alberta T2P 5H1	–	–	–
James M. Baggs 450 1st Street SW Calgary, Alberta T2P 5H1	–	–	–
Robert C. Jacobucci 450 1st Street SW Calgary, Alberta T2P 5H1	–	–	–
Directors and Executive officers as a Group[h][i] (14 people)	–	–	*

(a) A total of 46,227,766 common units are issued and outstanding.

(b) A deferred share unit is a bookkeeping entry, equivalent to the value of a Partnership 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.

(c) 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.

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

(e) TC PipeLines GP, Inc. is a wholly-owned indirect subsidiary of TransCanada and owns an aggregate two percent general partner interest of the Partnership.

(f) Based on Schedule 13D filed with the SEC on February 11, 2011 by Tortoise Capital Advisors, L.L.C. (Tortoise). In the Schedule 13D, Tortoise reported that it has shared power to vote 3,301,612 common units and shared power to dispose of all 3,428,859 common units.

(g) 4,888 common units are held by the Jenkins-Stark Family Trust dated June 16, 1995.

(h) With the exception of the one named director above, none of the other directors and executive officers hold any common units of the Partnership.

(i) Walentin (Val) Mirosh holds 720 shares of TransCanada; Kristine L. Delkus holds 93,479 options and 5,574 shares of TransCanada; Steven D. Becker holds 71,499 options and 14,887 shares of TransCanada; Terry C. Ofremchuk holds 1,600 options and 6,757 shares of TransCanada; Gregory A. Lohnes holds 184,089 options and 19,411 shares of TransCanada; Robert C. Jacobucci holds 600 shares of TransCanada; Donald J. DeGrandis holds 10,107 options and 425 shares of TransCanada; Rhonda L. Amundson holds 1,600 options and 3,756 shares of TransCanada; Annie C. Belecki holds 1,372 shares of TransCanada; James M. Baggs holds 61,225 options and 5,055 shares of TransCanada; Stephanie E. Wilson holds 843 shares of TransCanada; and Stuart P. Kampel holds 461 shares of TransCanada. The directors and executive officers as a group hold 423,599 options and 59,861 shares of TransCanada. All options listed above are exercisable within 60 days from February 25, 2011.

* Less than one percent.

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

At February 25, 2011, TransCanada owns 11,287,725 common units and the Partnership's General Partner owns 5,797,106 common units, representing an aggregate 36.2 percent limited partner interest in the Partnership. In addition, the General Partner owns an aggregate two percent 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 38.2 percent by virtue of its indirect ownership of the General Partner and 36.2 percent aggregate limited partner interest.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our General Partner and its affiliates, which includes TransCanada, in connection with the ongoing operation and liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arms-length negotiations.

	Operational Stage
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to common unitholders, including our general partner and its affiliates as holders of an aggregate of 17,084,831 common units, and the remaining 2% to our general partner.
Payments to our general partner and its affiliates	In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner will be entitled to increasing percentages of the distributions, up to 25% of the distributions above the highest target level. We refer to the rights to the increasing distributions as "incentive distribution rights". For further information about distributions, please read "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
	Liquidation Stage
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Reimbursement of Operating and General and Administrative Expense

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 $2.2 million for the year ended December 31, 2010 (2009 – $2.1 million; 2008 – $2.1 million).

Operating Agreements with Our Pipeline Companies

Our pipeline systems are operated by TransCanada and its affiliates pursuant to operating agreements. Under these agreements, our pipeline systems are required to reimburse TransCanada for their costs including payroll, employee benefit costs, and other costs incurred on behalf of our pipeline systems. Most costs for materials, services and other charges that are third-party charges are invoiced directly to each of our pipeline systems.

Cash Management Programs

Great Lakes has 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.

Transportation Agreements

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts with fixed prices. The contracts have remaining terms ranging from one to eight years. Great Lakes earned $148.5 million of transportation revenues under these contracts in 2010 (2009 – $141.7 million; 2008 – $143.7 million). This amount represents 56.6 percent of total revenues earned by Great Lakes in 2010 (2009 – 48.9 percent; 2008 – 50.0 percent). Great Lakes also earned $0.9 million in affiliated rental revenue in 2010 (2009 – $0.6 million; 2008 – 0.4 million).

Revenue from TransCanada and its affiliates of $69.3 million is included in the Partnership's equity income from Great Lakes in 2010 (2009 – $66.1 million; 2008 – $66.9 million). At December 31, 2010, $11.0 million was included in Great Lakes' receivables for transportation contracts with TransCanada and its affiliates (2009 – $12.9 million).

Great Lakes' largest shipper, TransCanada PipeLines Limited, has 576 MDth/d of long-haul capacity under contract expiring on October 31, 2011. Negotiations are currently in progress related to these contracts.

Other Agreements

Great Lakes, Northern Border, North Baja and Tuscarora currently have interconnection, operational balancing agreements, transportation and exchange agreements and/or other inter-affiliate agreements with affiliates of TransCanada. In addition, each of our pipeline systems currently have other routine agreements with TransCanada or one of its subsidiaries that arise in the ordinary course of business, including agreements for services and other transportation and exchange agreement and interconnection and balancing agreements with other TransCanada pipelines.

Costs charged to our pipeline systems for the years ended December 31, 2010, 2009 and 2008 by TransCanada and its affiliates and amounts payable to TransCanada and its affiliates at December 31, 2010 and 2009 are summarized in the following tables:

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Costs charged by TransCanada and its affiliates:			
Great Lakes	**30.3**	33.8	34.3
Northern Border[(a)]	**25.8**	25.5	30.5
North Baja[(b)]	**4.4**	2.9	4.7
Tuscarora	**3.7**	3.0	3.7
Impact on the Partnership's net income:			
Great Lakes	**12.8**	14.3	14.2
Northern Border	**12.5**	12.3	12.9
North Baja[(b)]	**3.2**	2.4	2.7
Tuscarora	**3.5**	2.8	2.7

December 31 *(millions of dollars)*	**2010**	2009
Amount payable to/(receivable from) TransCanada and its affiliates:		
Great Lakes	**3.0**	3.7
Northern Border	**2.2**	2.6
North Baja	**0.6**	(1.6)
Tuscarora	**0.7**	0.6

(a) In 2008, Northern Border's costs charged by TransCanada and its affiliates include $2.0 million of charges related to Bison through the effective date of the sale.

(b) Recast as discussed in Note 2 and Note 6 to the Partnership's financial statements included elsewhere in this report.

Relationship with our General Partner and TransCanada and Conflicts of Interest Resolution

Our Partnership Agreement contains specific provisions that address potential conflicts of interest between our General Partner and its affiliates, including TransCanada, on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our General Partner will resolve the conflict. Our General Partner may, but is not required to, seek the approval of such resolution from the conflicts committee of the board of directors of our General Partner ("Special Approval"), which is comprised of independent directors.

Any conflict of interest and any resolution of such conflict of interest shall be conclusively deemed fair and reasonable if such conflict of interest or resolution is approved by Special Approval:

- on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

The General Partner may also adopt a resolution or course of action that has not received Special Approval. In acting for the Partnership, the General Partner is accountable to us 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 the Partnership, 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, the Partnership, 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 the Partnership. 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, the Partnership. Further, the General Partner and its affiliates have no obligation to present business opportunities to the Partnership.
- The Partnership Agreement provides that the General Partner and its officers and directors will not be liable for monetary damages to the Partnership, 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.

The Partnership 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 the Partnership. Indemnification is required for criminal proceedings if the General Partner and others had no reasonable cause to believe their conduct was unlawful. Please read Item 10. "Directors, Executive Officers and Corporate Governance" for additional information.

Director Independence

Please read Item 10. "Directors, Executive Officers and Corporate Governance" for information about the independence of our General Partner's board of directors and its committees, which information is incorporated herein by reference in its entirety.

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 *(thousands of dollars)*	**2010**	2009
Audit Fees[(a)]	**358.8**	513.1
Tax Fees[(b)]	**–**	–
All Other Fees[(b)]	**–**	–
Total	**358.8**	513.1

(a) Audit fees include prospectus work in connection with the Partnership's November 2009 equity issuance and the filing of the Partnership's Form S-3 in April 2010. Audit fees also include services performed related to Sarbanes-Oxley Act reporting requirements, and includes services for the statutory audit of Tuscarora and North Baja.

(b) The Partnership has not engaged its external auditors for any tax or other services in 2010 or 2009.

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 any non-audit services, these services and fees are reviewed and approved by our Audit Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) (1) *Financial Statements*

See "Index to Financial Statements" set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

No.	Description
*2.1	Agreement for Purchase and Sale of Membership Interest by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership dated May 19, 2009 (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on May 20, 2009).
*2.1.1	First Amendment to Agreement for Purchase And Sale of Membership Interest by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership dated June 29, 2010 (Exhibit 2.1 to TC PipeLines, LP's Form 10-Q filed on July 29, 2010).
*3.1	Second Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated July 1, 2009 (Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*3.2	Certificate of Limited Partnership of TC PipeLines, LP (Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, filed on December 30, 1998).
*10.1	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).
10.1.1	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Great Lakes Gas Transmission Partnership between TransCanada GL, Inc., TC GL Intermediate Limited Partnership and Great Lakes Gas Transmission Company dated October 25, 2010.
*10.2	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).
*10.3	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company by and between Northern Border Intermediate Limited Partnership and TC Pipelines Intermediate Limited Partnership dated April 6, 2006 (Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006).
*10.4	Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. dated April 6, 2006 (Exhibit 10.2 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006).
*10.4.1	Amendment No.1 to Northern Border Pipeline Company Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated April 22, 2008 (Exhibit 10.9.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).

No.	Description
*10.4.2	Second Amendment of Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated February 10, 2010 (Exhibit 10.9.2 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*10.5	Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated December 19, 2006 (Exhibit 10.11 to TC PipeLines, LP's Form 10-K filed on March 2, 2007).
*10.5.1	First Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated June 21, 2007 (Exhibit 10.10.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.5.2	Second Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. (formerly TransCan Northwest Border Ltd.) dated December 31, 2007 (Exhibit 10.10.2 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.5.3	Third Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2008 (Exhibit 10.10.3 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.5.4	Fourth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2009 (Exhibit 10.10.4 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*10.6	Management Services Agreement by and between Gas Transmission Service Company, LLC (formally PG&E Gas Transmission Service Company, LLC) and North Baja Pipeline, LLC dated January 1, 2002 (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 4, 2009).
*10.7	Yuma Transfer Agreement by and between Gas Transmission Northwest Corporation and North Baja Pipeline, LLC dated March 5, 2010 (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 30, 2010).
*10.8	Amended and Restated Revolving Credit Agreement, dated 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 SunTrust Capital Markets, Inc. and Wachovia Capital Markets, LLC, as Co-Lead Arrangers and Book Managers (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on October 29, 2010).
*10.8.1	First Amendment to Amended and Restated Revolving Credit Agreement, dated 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).
*10.9	Amended and Restated Revolving Credit and Term Loan Agreement, dated February 13, 2007, 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 (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on October 29, 2010).
*10.10	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).

No.	Description
*10.11	Subordination and Intercreditor Agreement by and 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).
*10.12	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).
*10.13	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)).
*10.14	Form of Contribution, Conveyance and Assumption Agreement by and among TransCanada Border Pipeline Ltd., TransCan Northern Ltd., TransCanada PipeLines Limited, TC PipeLines, L.P., TC PipeLines Intermediate Limited Partnership and TC PipeLines GP, Inc. (Exhibit 10.2 to TC PipeLines, LP's Form S-1/A filed on May 3, 1999).
*#10.15	TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), effective as of October 18, 2007, as amended on December 10, 2008 (Exhibit 10.25 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.16	Membership Interest Purchase Agreement by and between Northern Border Pipeline Company and TransCanada Pipeline USA Ltd. dated August 28, 2008, (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on November 3, 2008).
*10.17	Common Unit Purchase Agreement by and between TC PipeLines, LP and TransCan Northern Ltd. dated July 1, 2009 (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*10.18	Exchange Agreement by and between TC PipeLines, LP and TC PipeLines GP, Inc. dated July 1, 2009 (Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
12.1	Computation of Ratio of Earnings to Fixed Charges.
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	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).
*99.2	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).

No.	Description
*99.3	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).
*99.4	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).
*99.5	Transportation Service Agreement FT11701 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 26, 2008. (Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*99.6	Transportation Service Agreement IT11986 between Great Lakes Gas Transmission Limited Partnership and TransCanada Gas Storage USA Inc., dated February 27, 2009. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2009).
*99.7	Transportation Service Agreement FT4760 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Exhibit 99.11 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.8	Transportation Service Agreement FT4761 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Exhibit 99.12 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.9	Transportation Service Agreement FT14131 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Exhibit 99.13 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*99.10	Transportation Service Agreement FT14132 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 1, 2009 (Exhibit 99.14 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Indicates exhibits incorporated by reference.

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

\# Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 25th day of February 2011.

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

By: /s/ STEVEN D. BECKER

Steven D. Becker
President
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ ROBERT C. JACOBUCCI

Robert C. Jacobucci
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/ GREGORY A. LOHNES Gregory A. Lohnes	Chairman,	February 25, 2011
/s/ STEVEN D. BECKER Steven D. Becker	President and Principal Executive Officer	February 25, 2011
/s/ ROBERT C. JACOBUCCI Robert C. Jacobucci	Controller and Principal Financial Officer	February 25, 2011
/s/ JAMES M. BAGGS James M. Baggs	Director	February 25, 2011
/s/ KRISTINE L. DELKUS Kristine L. Delkus	Director	February 25, 2011
/s/ WALENTIN (VAL) MIROSH Walentin (Val) Mirosh	Director	February 25, 2011
/s/ JACK F. JENKINS-STARK Jack F. Jenkins-Stark	Director	February 25, 2011
/s/ DAVID L. MARSHALL David L. Marshall	Director	February 25, 2011

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of TC PipeLines, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2010 and 2009, 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, 2010. We also have audited TC PipeLines, LP internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010, 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, 2010, 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 24, 2011

TC PIPELINES, LP

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2010**	2009
Assets		
Current Assets		
Cash and cash equivalents	**3.6**	3.1
Accounts receivable and other (Note 16)	**8.7**	8.6
	12.3	11.7
Investment in Great Lakes (Note 3)	**690.0**	691.2
Investment in Northern Border (Note 4)	**504.8**	523.0
Plant, property and equipment (Note 5)	**312.6**	318.0
Goodwill	**130.2**	130.2
Other assets	**0.6**	1.0
	1,650.5	1,675.1
Liabilities and Partners' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**7.7**	4.5
Accrued interest	**1.3**	1.3
Current portion of long-term debt (Note 7)	**483.8**	53.4
Current portion of fair value of derivative contracts (Note 15)	**13.8**	12.9
	506.6	72.1
Long-term debt (Note 7)	**30.1**	487.9
Fair value of derivative contracts and other (Note 15)	**1.3**	11.6
	538.0	571.6
Partners' Equity (Note 8)		
Common units	**1,104.2**	1,105.6
General partner	**23.5**	23.6
Accumulated other comprehensive loss	**(15.2)**	(25.7)
	1,112.5	1,103.5
	1,650.5	1,675.1

Subsequent events (Note 17)

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

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 (millions of dollars except per common unit amounts)	**2010**	2009[(a)]	2008[(a)]
Equity income from investment in Great Lakes (Note 3)	**58.7**	59.1	57.3
Equity income from investment in Northern Border (Note 4)	**67.3**	40.3	65.3
Transmission revenues	**69.1**	67.9	64.5
Operating expenses	**(13.0)**	(11.0)	(11.5)
General and administrative	**(4.4)**	(6.2)	(4.1)
Depreciation (Note 5)	**(15.0)**	(14.7)	(13.9)
Financial charges and other (Note 9)	**(25.6)**	(29.3)	(34.6)
Net income	**137.1**	106.1	123.0
Net income allocation (Note 10)			
Common units	**134.4**	90.6	95.1
General partner	**2.7**	7.2	12.6
	137.1	97.8	107.7
Net income per common unit (Note 10)	**$2.91**	$2.34	$2.73
Weighted average common units outstanding *(millions)*	**46.2**	38.7	34.9
Common units outstanding, end of year *(millions)*	**46.2**	46.2	34.9

(a) Recast as discussed in Notes 2 and 6.

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Net income[(a)]	**137.1**	106.1	123.0
Other comprehensive income/(loss)			
Change associated with current period hedging transactions (Note 15)	**10.0**	7.9	(22.0)
Change associated with current period hedging transactions of investees	**0.5**	1.3	(1.6)
	10.5	9.2	(23.6)
Total comprehensive income	**147.6**	115.3	99.4

(a) Recast as discussed in Notes 2 and 6.

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2010**	2009[a]	2008[a]
Cash Generated From Operations			
Net income	**137.1**	106.1	123.0
Depreciation (Note 5)	**15.0**	14.7	13.9
Amortization of other assets (Note 9)	**0.5**	0.4	0.5
Increase in other long-term liabilities	**0.7**	0.2	0.1
Equity allowance for funds used during construction	**(0.3)**	(0.5)	(1.1)
Decrease/(increase) in operating working capital (Note 12)	**3.1**	2.5	(4.2)
	156.1	123.4	132.2
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Great Lakes	**10.5**	13.4	16.6
Northern Border	**18.7**	35.4	25.4
Investment in Great Lakes (Note 3)	**(9.3)**	(0.1)	–
Investment in Northern Border (Notes 4)	**–**	(42.3)	–
Acquisition of North Baja, net of cash acquired (Note 6)	**–**	(271.4)	–
Capital expenditures	**(9.3)**	(1.9)	(34.6)
Other assets	**(0.1)**	0.1	–
Increase in investing working capital (Note 12)	**–**	(2.9)	(3.7)
	10.5	(269.7)	3.7
Financing Activities			
Distributions paid (Note 11)	**(138.7)**	(117.0)	(108.6)
Equity issuances, net	**–**	265.6	–
Long-term debt issued (Note 7)	**74.0**	208.0	4.0
Long-term debt repaid (Note 7)	**(101.4)**	(203.5)	(40.6)
Due to North Baja's former parent (Note 6)	**–**	(12.1)	10.2
	(166.1)	141.0	(135.0)
Increase/(decrease) in cash and cash equivalents	**0.5**	(5.3)	0.9
Cash and cash equivalents, beginning of year	**3.1**	8.4	7.5
Cash and cash equivalents, end of year	**3.6**	3.1	8.4
Interest payments made	**8.5**	16.5	30.3

[a] Recast as discussed in Notes 2 and 6.

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

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

	Common Units		General Partner	Accumulated Other Comprehensive Loss[a]	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, 2007	34.9	892.3	19.1	(11.3)	34.9	900.1
Net income[b]	–	110.9	12.1	–	–	123.0
Net income attributed to former North Baja owner	–	(15.0)	(0.3)	–	–	(15.3)
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
Net income[b]	–	98.8	7.3	–	–	106.1
Net income attributed to former North Baja owner	–	(8.2)	(0.1)	–	–	(8.3)
Equity issuances, net (Notes 6 and 8)	11.3	260.2	5.4	–	11.3	265.6
Distributions paid	–	(109.4)	(7.6)	–	–	(117.0)
Excess purchase price over net acquired assets[c]	–	(27.2)	(0.5)	–	–	(27.7)
Other comprehensive income	–	–	–	9.2	–	9.2
Partners' equity at December 31, 2009	46.2	1,105.6	23.6	(25.7)	46.2	1,103.5
Net income	–	134.4	2.7	–	–	137.1
Distributions paid	–	(135.9)	(2.8)	–	–	(138.7)
Assets acquired in excess of purchase price[c]	–	0.1	–	–	–	0.1
Other comprehensive income	–	–	–	10.5	–	10.5
Partners' equity at December 31, 2010	**46.2**	**1,104.2**	**23.5**	**(15.2)**	**46.2**	**1,112.5**

(a) The Partnership uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at December 31, 2010, the amount of losses related to cash flow hedges reported in accumulated other comprehensive income that is expected to be reclassified to net income in the next 12 months is $13.8 million, which will be offset by a reduction to interest expense of a similar amount.

(b) Recast as discussed in Notes 2 and 6.

(c) Accounting adjustment for common control transaction. See Note 6 for details.

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

TC PIPELINES, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiaries are collectively referred to herein as the Partnership. The Partnership 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.

The Partnership owns the following interests in natural gas pipeline systems:

- a 46.45 percent 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;
- a 50 percent general partner interest in Northern Border Pipeline Company (Northern Border), a Texas general partnership. Northern Border owns a 1,398-mile U.S. interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to markets in the Midwestern U.S.;
- a 100 percent interest in North Baja Pipeline, LLC (North Baja), a Delaware limited liability company. North Baja owns an 86-mile U.S. interstate pipeline system that transports natural gas between an interconnection with El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection near Ogilby, California on the California/Mexico border with the Gasoducto Bajanorte natural gas pipeline system; and
- a 100 percent interest in Tuscarora Gas Transmission Company (Tuscarora), a Nevada general partnership. Tuscarora owns a 305-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.

The Partnership is managed by its General Partner, TC PipeLines GP, Inc. (TC PipeLines GP), a wholly-owned subsidiary of TransCanada. The General Partner provides management and operating services for the Partnership and is reimbursed for its costs and expenses. In addition to its aggregate two percent general partner interest in the Partnership, the General Partner owns 5,797,106 common units, representing an effective 14.3 percent interest in the Partnership at December 31, 2010. TransCanada also indirectly holds 11,287,725 common units representing an effective 23.9 percent limited partner interest in the Partnership at December 31, 2010.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The accompanying financial statements and related notes present the financial position of the Partnership as at December 31, 2010 and 2009 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2010, 2009 and 2008. 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. The Partnership consolidates its investments in North Baja and Tuscarora.

On July 1, 2009, the Partnership acquired a 100 percent interest in North Baja from TransCanada. The acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented on a consolidated basis. Refer to Note 6 for additional disclosure regarding the North Baja acquisition.

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 United States of America (U.S.) generally accepted accounting principles (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. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and include all adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the financial results for the periods presented.

(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 North Baja and 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 and compression equipment of 25 to 30 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 tests its long-lived assets 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 to North Baja and Tuscarora operations 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 at December 31, 2010, 2009 and 2008, the Partnership has not recognized any transmission revenue that is subject to possible refund.

(g) Income Taxes

The Partnership 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 from third parties 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.

The Partnership accounts for business acquisitions between entities under common control using a method similar to a pooling of interests, whereby the assets and liabilities of the acquired entities are recorded at TransCanada's carrying value and the Partnership's historical financial information is recast to include the acquired entities for all periods presented. If the fair market value paid for the acquired entities is greater than the recorded net assets of the acquired entities, the excess purchase price paid is recorded as a reduction to Partners' Equity. Similarly, if the fair market value paid for the acquired entities is less than the recorded net assets of the acquired entities, the excess of assets acquired is recorded as an increase to Partners' Equity.

(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.

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

The Partnership recognizes and measures liabilities associated with the retirement of tangible long-lived assets at fair value as incurred and capitalize them 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 relevant long-lived 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.

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.

(k) Government Regulation

North Baja and Tuscarora, the Partnership's wholly-owned pipeline systems, are subject to regulation by the FERC. Under regulatory accounting principles, 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 regulatory accounting, considering such factors as regulatory changes, the impact of competition, and the ability to recover regulatory assets. As at December 31, 2010, Tuscarora has no regulatory assets (2009 – nil) and $0.5 million in regulatory liabilities (2009 – nil). North Baja has no regulatory assets or liabilities as at December 31, 2010 and 2009. Allowance for funds used during construction is capitalized and included in plant, property and equipment.

(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

The Partnership owns a 46.45 percent general interest in Great Lakes. TransCanada owns the other 53.55 percent partnership interest and is also 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. The Partnership holds a 98.9899 percent limited partnership interest in TC GL Intermediate Limited Partnership.

On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 (November 2009 Order) instituting an investigation pursuant to Section 5 of the Natural Gas Act (GL Rate Proceeding). The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable. As a result of extensive settlement negotiations, in July 2010, the FERC approved the settlement without modification, establishing the terms pursuant to which all matters in the GL Rate Proceeding were resolved. The settlement was effective May 1, 2010 and applies to all current and future shippers on Great Lakes' system.

The Partnership uses the equity method of accounting for its investment in Great Lakes. The Partnership's equity income from its investment in Great Lakes amounted to $58.7 million for the year ended December 31, 2010 (2009 – $59.1 million; 2008 – $57.3). Great Lakes had no undistributed earnings for the years ended December 31, 2010, 2009, and 2008.

At December 31, 2010 and 2009, the partnership had a $458.4 million difference between the carrying value of Great Lakes and the underlying equity in the net assets primarily resulting from the recognition of goodwill as part of the Partnership's investment in Great Lakes relating to the Partnership's February 2007 acquisition of a 46.45 percent general interest in Great Lakes.

The Partnership made an equity contribution of $4.6 million to Great Lakes in 2010. This amount represents the Partnership's 46.45 percent share of a $10.0 million cash call issued by Great Lakes to expand backhaul capacity from St. Clair, Michigan, U.S. to Emerson, Manitoba, Canada. The Partnership also made an equity contribution of $4.7 million to Great Lakes in 2010, which represents the Partnership's 46.45 percent share of a $10.0 million cash call from Great Lakes to make a scheduled debt repayment and is the result of a change in Great Lakes' distribution policy in 2010, whereby Great Lakes commenced funding its debt repayments with cash calls to its partners and making distributions to its partners before deducting amounts for debt repayments.

The following tables contain summarized financial information of Great Lakes as at December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008:

Summarized Consolidated Great Lakes Balance Sheet

December 31 (millions of dollars)	**2010**	2009
Assets		
Cash and cash equivalents	**–**	0.1
Other current assets	**83.7**	82.3
Plant, property and equipment, net	**846.9**	873.3
Other assets	**0.6**	0.7
	931.2	956.4
Liabilities and Partners' Equity		
Current liabilities	**34.9**	40.3
Deferred credits	**5.6**	3.8
Long-term debt, including current maturities	**392.0**	411.0
Partners' capital	**498.7**	501.3
	931.2	956.4

Summarized Consolidated Great Lakes Income Statement

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Transmission revenues	**262.4**	289.7	287.1
Operating expenses	**(59.2)**	(66.5)	(67.1)
Depreciation	**(40.5)**	(58.5)	(58.5)
Financial charges and other	**(30.9)**	(31.9)	(32.6)
Michigan business tax	**(5.3)**	(5.4)	(5.5)
Net income	**126.5**	127.4	123.4

NOTE 4 INVESTMENT IN NORTHERN BORDER

The Partnership owns a 50 percent general partner interest in Northern Border. The other 50 percent partnership interest in Northern Border is held by ONEOK Partners, L.P., a publicly traded limited partnership. Northern Border is regulated by the FERC. Northern Border is operated by TransCanada.

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

The Partnership uses the equity method of accounting for its investment in Northern Border. The Partnership's equity income from its investment in Northern Border amounted to $67.3 million for the year ended December 31, 2010 (2009 – $40.3 million; 2008 – $65.3 million). Equity income from Northern Border includes a twelve-year 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 percent acquisition in April 2006. Northern Border had no undistributed earnings for the years ended December 31, 2010, 2009 and 2008.

At December 31, 2010, the Partnership had a $120.8 million (2009 – $121.2 million) difference between the carrying value of Northern Border and the underlying equity in the net assets primarily resulting from the recognition of goodwill as part of the Partnership's investment in Northern Border relating to the Partnership's April 2006 acquisition of an additional 20 percent general partnership interest in Northern Border.

The following tables contain summarized financial information of Northern Border as at December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008:

Summarized Northern Border Balance Sheet

December 31 (millions of dollars)	**2010**	2009
Assets		
Cash and cash equivalents	**10.2**	16.9
Other current assets	**37.1**	30.2
Plant, property and equipment, net	**1,294.8**	1,343.1
Other assets	**22.9**	24.2
	1,365.0	1,414.4
Liabilities and Partners' Equity		
Current liabilities	**46.7**	38.0
Deferred credits and other	**9.7**	8.3
Long-term debt, including current maturities	**540.6**	564.6
Partners' equity		
Partners' capital	**770.9**	806.6
Accumulated other comprehensive loss	**(2.9)**	(3.1)
	1,365.0	1,414.4

Summarized Northern Border Income Statement

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Transmission revenues	**295.1**	249.2	293.1
Operating expenses	**(74.0)**	(70.8)	(78.0)
Depreciation	**(61.5)**	(61.9)	(61.1)
Financial charges and other *(Note 13)*	**(23.4)**	(34.4)	(21.8)
Net income	**136.2**	82.1	132.2

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2010			2009		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**290.1**	**100.6**	**189.5**	279.6	90.7	188.9
Compression	**113.4**	**24.5**	**88.9**	113.4	20.5	92.9
Metering and other	**42.2**	**8.2**	**34.0**	37.5	7.1	30.4
Under construction	**0.2**	**–**	**0.2**	5.8	–	5.8
	445.9	**133.3**	**312.6**	436.3	118.3	318.0

NOTE 6 ACQUISITIONS AND REVISED INCENTIVE DISTRIBUTION RIGHTS

On July 1, 2009, the Partnership acquired a 100 percent interest in North Baja, a Delaware limited liability company, from TransCanada. The North Baja pipeline system extends from an interconnection with EPNG near Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border where it connects with the Gasoducto Bajanorte natural gas pipeline system owned by Sempra Energy International. North Baja is regulated by the FERC and is operated by TransCanada.

The purchase price of $271.4 million was financed through a combination of (i) a draw of $170.0 million on the Partnership's $250.0 million revolving portion of its revolving credit and term loan agreement (Senior Credit Facility), (ii) issuance of 2,609,680 common units at $30.042 per common unit to TransCanada for gross proceeds of $78.4 million, (iii) issuance of additional general partner interest to the General Partner of $1.6 million, which was required to maintain the General Partner's two percent general partner interest in the Partnership, and (iv) approximately $21.4 million of cash on hand.

The acquisition of North Baja was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership's historical financial information was recast to include North Baja for all periods presented. The purchase price was recorded as follows: Working capital of $2.0 million; Plant, property and equipment of $193.5 million; Goodwill of $48.5 million; Other assets of $0.1 million; and Other long-term liabilities of $0.4 million. As the fair value paid for North Baja was greater than the recorded net assets of North Baja, the excess purchase price paid of $27.7 million was recorded as a reduction to Partners' Equity. The effect of recasting the Partnership's consolidated financial statements to account for the common control transaction increased the Partnership's net income by $8.3 million and $15.3 million for the years ended December 31, 2009 and 2008, respectively, from amounts previously reported.

Concurrent with the acquisition of North Baja, the Partnership entered into an exchange agreement with its General Partner whereby the Partnership issued 3,762,000 common units to the General Partner and provided for revised incentive distribution rights (Revised IDRs) in exchange for the cancellation of the incentive distribution rights available to the General Partner (Old IDRs) under the Amended and Restated Agreement of Limited Partnership of the Partnership.

Under the terms of the Revised IDRs, the distributions to the General Partner were reset to two percent, down from the General Partner distribution levels of the Old IDRs at 50 percent (for combined general partner interest and incentive distribution interest). The incentive distribution levels of the Revised IDRs will result in increased combined distributions to the General Partner (for general partner interest and incentive distribution interest) of 15 percent and a maximum of 25 percent when quarterly distributions increase to $0.81 and $0.88 per common unit or $3.24 and $3.52 per common unit on an annualized basis, respectively.

At the time of the July 1, 2009 acquisition of North Baja, TransCanada had begun an expansion project of the North Baja pipeline from the Mexico/Arizona border to Yuma, Arizona (Yuma Lateral). The Partnership agreed to acquire the expansion facilities and contracts for an additional sum up to $10.0 million, if TransCanada completed the project by June 30, 2010. On March 5, 2010, the Partnership acquired the expansion facilities and contracts in place at that time for a purchase price of $7.6 million. The Yuma Lateral was placed into service on March 13, 2010. The North Baja Acquisition Agreement provided that an additional payment of up to $2.4 million be made to TransCanada in the event that any other shippers contracted for services on the Yuma Lateral before June 30, 2010. A potential shipper signed a precedent agreement with North Baja on June 29, 2010 to enter into agreements for service on the Yuma Lateral. Accordingly, an amendment to the Acquisition Agreement between the Partnership and TransCanada was entered into on June 29, 2010 to allow TransCanada to continue to pursue additional contracts until December 31, 2010. On July 28, 2010, TransCanada secured additional contracts and, as a result, an additional payment of up to $2.4 million will be paid to TransCanada when the facilities associated with the additional contracts go into service which is anticipated in first quarter 2011.

The Yuma Lateral asset purchase was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets acquired were recorded at TransCanada's carrying value. As the fair value paid for the Yuma Lateral assets of $7.6 million was less than the $7.7 million recorded as plant, property and equipment, the excess amount of assets acquired of $0.1 million was recorded as an increase to Partners' Equity at December 31, 2010.

NOTE 7 CREDIT FACILITIES AND LONG-TERM DEBT

December 31 (millions of dollars)	**2010**	2009
Senior Credit Facility due 2011	**483.0**	484.0
7.13% Series A Senior Notes due 2010	**–**	48.2
7.99% Series B Senior Notes due 2010	**–**	4.4
6.89% Series C Senior Notes due 2012	**3.9**	4.7
3.82% Series D Senior Notes due 2017	**27.0**	–
	513.9	541.3
Less: current portion of long-term debt	**483.8**	53.4
	30.1	487.9

The Partnership's Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility with a banking syndicate. At December 31, 2010, $475.0 million remained outstanding under the senior term loan (2009 – $475.0 million) and $8.0 million was outstanding under the senior revolving credit facility (2009 – $9.0 million), leaving $242.0 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. However, once a senior term loan is repaid, it cannot be re-borrowed. Borrowings under the Senior Credit Facility 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 $483.0 million outstanding under the Senior Credit Facility at December 31, 2010 (2009 – $484.0 million). The interest rate on the Senior Credit Facility averaged 0.91 percent for the year ended December 31, 2010 (2009 – 1.42 percent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.30 percent for the year ended December 31, 2010 (2009 – 4.10 percent). Prior to hedging activities, the interest rate was 0.83 percent at December 31, 2010 (2009 – 0.97 percent).

At December 31, 2010, 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.

On December 21, 2010, Tuscarora's Series A and B Senior Notes matured. Also on December 21, 2010, Tuscarora issued $27.0 million of 3.82 percent Series D Senior Notes, which require principal and interest payments over approximately seven years. The Series D Senior Notes mature on August 21, 2017.

Series C and D 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 principal repayments required on the long-term debt are as follows:

(millions of dollars)	
2011	483.8
2012	3.1
2013	3.5
2014	3.6
2015	3.7
Thereafter	16.2
	513.9

On April 22, 2010, the Partnership filed an automatic universal shelf registration statement on Form S-3 (ASR) with the Securities and Exchange Commission, which replaced the universal shelf registration filed in December 2008. The ASR will allow the Partnership to issue an indeterminate amount of securities of the Partnership, including both senior and subordinated debt securities and/or common units representing limited partnership interests in the Partnership. The ASR was effective immediately upon filing and will expire April 22, 2013.

NOTE 8 PARTNERS' EQUITY

At December 31, 2010, Partners' equity includes 46,227,766 common units (2009 – 46,227,766 common units) representing an aggregate 98 percent limited partner interest in the Partnership (including 5,797,106 common units held by the General Partner and 11,287,725 common units held indirectly by TransCanada) and an aggregate two percent general partner interest. In aggregate, the General Partner's interests represent an effective 14.3 percent ownership in the Partnership at December 31, 2010 (December 31, 2009 – 14.3 percent).

On November 18, 2009, the Partnership completed a public offering of 5,000,000 common units at $38.00 per common unit for gross proceeds of $190.0 million and net proceeds of $181.8 million after unit issuance costs. TC PipeLines GP maintained its two percent general partner interest in the Partnership by contributing $3.8 million to the Partnership in connection with the offering.

Refer to Note 6 for disclosure regarding the equity issuance in connection with the acquisition of North Baja in 2009.

NOTE 9 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Interest expense on long-term debt	**8.4**	12.5	23.4
Interest expense on short-term debt[a]	**–**	2.1	6.0
Capitalized interest[a]	**(0.2)**	(0.4)	(1.4)
Loss on interest rate swaps and options	**16.5**	15.1	6.9
Interest income[a]	**–**	(0.4)	(0.8)
Amortization of other assets	**0.5**	0.4	0.5
Other	**0.4**	–	–
	25.6	29.3	34.6

[a] Recast as discussed in Notes 2 and 6.

NOTE 10 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 percent interest, plus an amount equal to incentive distributions. Incentive distributions are paid to 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:

(millions of dollars except per unit)	**2010**	2009	2008
Net income[a]	**137.1**	106.1	123.0
North Baja's contribution prior to acquisition	**–**	(8.3)	(15.3)
Net income allocated to partners[b]	**137.1**	97.8	107.7
Net income allocated to general partner:			
General partner interest	**(2.7)**	(1.9)	(2.2)
Incentive distribution income allocation	**–**	(5.3)	(10.4)
	(2.7)	(7.2)	(12.6)
Net income allocable to common units	**134.4**	90.6	95.1
Weighted average common units outstanding *(millions)*	**46.2**	38.7	34.9
Net income per common unit	**$2.91**	$2.34	$2.73

[a] Recast as discussed in Notes 2 and 6.

[b] Net income allocated to partners excludes North Baja's earnings prior to the Partnership's acquisition of North Baja on July 1, 2009, as the earnings of North Baja prior to that date were allocated to TransCanada and were not allocable to either the General Partner or common units.

NOTE 11 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, as defined in the Partnership Agreement, 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 $0.75 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. Prior to July 1, 2009, the combined general partner interest and incentive distribution interest payable to the General Partner were 15 percent, 25 percent, and 50 percent of all quarterly distributions of Available Cash that exceed target levels of $0.45, $0.5275 and $0.69 per common unit, respectively. On July 1, 2009, the incentive distributions were revised under the Second Amended and Restated Agreement of Limited Partnership of the Partnership. Currently, the combined general partner interest and incentive distribution interest payable to the General Partner are 15 percent and a maximum of 25 percent of all quarterly distributions of Available Cash that exceed target levels of $0.81 and $0.88, respectively, per common unit.

For the year ended December 31, 2010, the Partnership distributed $2.94 per common unit (2009 – $2.87 per common unit; 2008 – $2.75 per common unit). The distributions paid for the year ended December 31, 2010 included no incentive distributions to the General Partner (2009 – $5.3 million; 2008 – $9.7 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 percent to the General Partner.

NOTE 12 CHANGE IN WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2010**	2009[a]	2008[a]
(Increase)/decrease in accounts receivable and other	**(0.1)**	2.8	(0.6)
Decrease in bank indebtedness	**–**	–	(1.4)
Increase/(decrease) in accounts payable and accrued liabilities	**3.2**	(0.8)	(5.0)
Decrease in accrued interest	**–**	(2.4)	(0.9)
	3.1	(0.4)	(7.9)
Increase in investing working capital	**–**	(2.9)	(3.7)
Decrease/(increase) in operating working capital	**3.1**	2.5	(4.2)

[a] Recast as discussed in Notes 2 and 6.

NOTE 13 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the General Partner. The General Partner does not receive a management fee 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 $2.2 million for the year ended December 31, 2010 (2009 – $2.1 million; 2008 – $2.1 million).

As operator, TransCanada and its affiliates provide capital and operating services to Great Lakes, Northern Border, North Baja 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, and property and liability insurance costs.

Costs charged to our pipeline systems for the years ended December 31, 2010, 2009 and 2008 by TransCanada and its affiliates and amounts payable to TransCanada and its affiliates at December 31, 2010 and 2009 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Costs charged by TransCanada and its affiliates:			
Great Lakes	**30.3**	33.8	34.3
Northern Border[(a)]	**25.8**	25.5	30.5
North Baja[(b)]	**4.4**	2.9	4.7
Tuscarora	**3.7**	3.0	3.7
Impact on the Partnership's net income:			
Great Lakes	**12.8**	14.3	14.2
Northern Border	**12.5**	12.3	12.9
North Baja[(b)]	**3.2**	2.4	2.7
Tuscarora	**3.5**	2.8	2.7

December 31 (millions of dollars)	**2010**	2009
Amount payable to/(receivable from) TransCanada and its affiliates:		
Great Lakes	**3.0**	3.7
Northern Border	**2.2**	2.6
North Baja	**0.6**	(1.6)
Tuscarora	**0.7**	0.6

(a) In 2008, 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.

(b) Recast as discussed in Notes 2 and 6.

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts with fixed prices. The contracts have remaining terms ranging from one to eight years. Great Lakes earned $148.5 million of transportation revenues under these contracts in 2010 (2009 – $141.7 million; 2008 – $143.7 million). This amount represents 56.6 percent of total revenues earned by Great Lakes in 2010 (2009 – 48.9 percent; 2008 – 50.0 percent). Great Lakes also earned $0.9 million in affiliated rental revenue in 2010 (2009 – $0.6 million; 2008 – $0.4 million).

Revenue from TransCanada and its affiliates of $69.3 million is included in the calculation of the Partnership's equity income from Great Lakes in 2010 (2009 – $66.1 million; 2008 – $66.9 million). At December 31, 2010, $11.0 million was included in Great Lakes' receivables for transportation contracts with TransCanada and its affiliates (2009 – $12.9 million).

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, entered into an Interconnect Agreement, which provided that Northern Border would reimburse ANR for the cost of the interconnect facilities to be owned by ANR. In June 2008, Northern Border paid ANR $0.5 million.

NOTE 14 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2010 and 2009:

Quarter ended (millions of dollars except per common unit amounts)	**Mar 31**	**Jun 30**	**Sep 30**	**Dec 31**
2010				
Equity income	**30.9**	**25.3**	**35.6**	**34.2**
Transmission revenues	**17.4**	**17.0**	**17.4**	**17.3**
Net income	**33.7**	**27.7**	**38.6**	**37.1**
Net income per common unit	**$0.71**	**$0.59**	**$0.82**	**$0.79**
Cash distributions paid	**34.4**	**34.4**	**34.4**	**35.4**
2009				
Equity income	35.1	18.3	23.7	22.3
Transmission revenues[(a)]	16.8	16.8	17.5	16.8
Net income[(a)]	35.9	17.9	27.4	24.9
Net income per common unit	$0.82	$0.31	$0.65	$0.56
Cash distributions paid	27.7	27.8	30.8	30.7

(a) Recast as discussed in Notes 2 and 6.

NOTE 15 FINANCIAL INSTRUMENTS

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

The estimated fair values of the Partnership's and its subsidiary's long-term debt as at December 31, 2010 and 2009 are as follows:

	2010		2009	
December 31 (millions of dollars)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Senior Credit Facility	**483.0**	**483.0**	484.0	484.0
Series A Senior Notes	**–**	**–**	48.2	50.8
Series B Senior Notes	**–**	**–**	4.4	4.7
Series C Senior Notes	**3.9**	**4.3**	4.7	5.2
Series D Senior Notes	**27.0**	**26.6**	–	–
	513.9	**513.9**	541.3	544.7

The Partnership's 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 $375.0 million at December 31, 2010 (2009 – $375.0 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 percent. $75.0 million of variable-rate debt is hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid is 3.86 percent. $100.0 million of variable-rate debt was hedged by an interest rate option through May 22, 2009 at an interest rate range between a weighted average floor of 4.09 percent and a cap of 5.35 percent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement.

Financial instruments are recorded at fair value on a recurring basis and are categorized into one of three categories based upon a fair value hierarchy. The Partnership has classified all of its derivative financial instruments as Level II for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At December 31, 2010, the fair value of the interest rate swaps accounted for as hedges was negative $13.8 million (2009 – negative $23.8 million), of which $13.8 million is classified as a current liability (2009 – $12.9 million). The fair value of the interest rate swaps was calculated using the year end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. In 2010, the Partnership recorded interest expense of $16.5 million on the interest rate swaps and options (2009 – $15.1 million; 2008 – $6.9 million).

NOTE 16 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2010**	2009
Accounts receivable	**7.6**	7.4
Inventory	**0.7**	0.6
Prepayments	**0.4**	0.5
Other assets	**–**	0.1
	8.7	8.6

[a] Recast as discussed in Notes 2 and 6.

NOTE 17 SUBSEQUENT EVENTS

On January 18, 2011, the board of directors of our General Partner declared the Partnership's fourth quarter 2010 cash distribution in the amount of $0.75 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2011 to unitholders of record as of January 31, 2011, totaled $35.4 million and was paid in the following manner: $34.7 million to common unitholders (including $4.3 million to the General Partner as holder of 5,797,106 common units and $8.5 million to TransCanada as holder of 11,287,725 common units) and $0.7 million to the General Partner in respect of its two percent general partner interest. The fourth quarter 2010 cash distribution represents an annual cash distribution of $2.96 per common unit.

Great Lakes declared and paid its fourth quarter 2010 distribution of $36.3 million on February 1, 2011, of which the Partnership received its 46.45 percent share or $16.9 million.

Northern Border declared and paid its fourth quarter 2010 distribution of $51.5 million on February 1, 2011, of which the Partnership received its 50 percent share or $25.8 million.

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 Lake Gas Transmission Limited Partnership and subsidiary (the Partnership) as of December 31, 2010 and 2009, and the related consolidated statements of income, partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2010. 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 consolidated financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 10, 2011

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED BALANCE SHEETS

December 31 (In thousands)	**2010**	2009
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 40**	125
Demand loan receivable from affiliate	**44,924**	33,974
Accounts receivable:		
Trade, net of allowance of $250 in 2009	**14,610**	22,980
Affiliates	**11,286**	12,922
Materials and supplies	**10,824**	10,235
Other	**1,990**	2,137
Total current assets	**83,674**	82,373
Property, plant, and equipment:		
Property, plant, and equipment	**2,064,641**	2,051,274
Construction work in progress	**1,875**	3,034
	2,066,516	2,054,308
Less accumulated depreciation and amortization	**(1,219,579)**	(1,181,042)
Total property, plant, and equipment, net	**846,937**	873,266
Other assets	**638**	719
Total assets	**$ 931,249**	956,358
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable:		
Trade	**$ 11,660**	14,355
Affiliates	**2,976**	3,674
Current maturities of long-term debt	**19,000**	19,000
Partnership income taxes payable	**3,729**	2,887
Taxes payable (other than income)	**8,194**	10,541
Accrued interest	**8,384**	8,690
Other	**38**	140
Total current liabilities	**53,981**	59,287
Long-term debt, net of current maturities	**373,000**	392,000
Other liabilities:		
Deferred partnership income taxes	**5,169**	3,337
Other	**436**	436
Total other liabilities	**5,605**	3,773
Partners' capital	**498,663**	501,298
Total liabilities and partners' capital	**$ 931,249**	956,358

See accompanying notes to consolidated financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF INCOME AND PARTNERS' CAPITAL

Years ended December 31 (In thousands)	**2010**	2009	2008
Operating revenues	**$ 262,391**	289,693	287,130
Operating expenses:			
Operation and maintenance	**41,558**	48,760	46,276
Depreciation and amortization	**40,488**	58,503	58,522
Taxes, other than income	**17,694**	17,729	20,788
Total operating expenses	**99,740**	124,992	125,586
Operating income	**162,651**	164,701	161,544
Other income, net	**238**	595	1,300
Interest and debt expense	**(31,339)**	(32,916)	(34,358)
Affiliated interest income	**205**	449	453
Income before partnership income taxes	**131,755**	132,829	128,939
Partnership income taxes	**(5,290)**	(5,417)	(5,503)
Net income	**$ 126,465**	127,412	123,436
Partners' capital:			
Balance at beginning of year	**$ 501,298**	529,886	565,650
Net income	**126,465**	127,412	123,436
Distributions to partners	**(149,100)**	(156,000)	(159,200)
Contributions from partners	**20,000**	–	–
Balance at end of year	**$ 498,663**	501,298	529,886

See accompanying notes to consolidated financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 (In thousands)	**2010**	2009	2008
Cash flows from operating activities:			
Net Income	**$ 126,465**	127,412	123,436
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**40,488**	58,503	58,522
Deferred partnership income taxes	**1,816**	1,410	1,927
Allowance for funds used during construction, equity	**(187)**	(78)	(195)
Asset and liability changes:			
Accounts receivable	**10,006**	3,775	1,159
Other current assets	**(442)**	1,967	(539)
Noncurrent assets	**97**	24	138
Accounts payable	**(3,393)**	(4,084)	(6,226)
Partnership income taxes payable	**842**	2,887	–
Other current liabilities	**(2,755)**	(1,530)	(1,451)
Noncurrent liabilities	**–**	19	21
Net cash provided by operating activities	**172,937**	190,305	176,792
Cash flows from investing activities:			
Additions to property, plant, and equipment	**(13,972)**	(8,310)	(12,448)
Net change in demand loan receivable from affiliate	**(10,950)**	(8,507)	(25,467)
Net cash used in investing activities	**(24,922)**	(16,817)	(37,915)
Cash flows from financing activities:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(10,000)
Distributions to partners	**(149,100)**	(156,000)	(159,200)
Contributions from partners	**20,000**	–	–
Net cash used in financing activities	**(148,100)**	(175,000)	(169,200)
Net decrease in cash and cash equivalents	**(85)**	(1,512)	(30,323)
Cash and cash equivalents at beginning of year	**125**	1,637	31,960
Cash and cash equivalents at end of year	**$ 40**	125	1,637
Supplemental cash flow information:			
Cash activities:			
Interest paid, net of capitalized interest	**$ 31,582**	33,159	34,440
Partnership income taxes paid	**2,873**	–	2,574

See accompanying notes to consolidated financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

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 (U.S.) and eastern Canada. The partners and partnership ownership percentages at December 31, 2010 and 2009 are as follows:

	Ownership %
General Partners:	
TransCanada GL, Inc.	46.45
TC GL Intermediate Limited Partnership	46.45
Limited Partner:	
Great Lakes Gas Transmission Company	7.10

Great Lakes Gas Transmission Company (the Company) and TransCanada GL, Inc. are wholly owned indirect subsidiaries of TransCanada Corporation (TransCanada). TC GL Intermediate Limited Partnership is a direct subsidiary of TC PipeLines, LP of which TransCanada indirectly owns a 38.2% interest.

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary. GLGT Aviation Company owned a fractional interest in a transport aircraft used principally for pipeline operations until October 2009 when its interest in the aircraft was sold. In December 2009, GLGT Aviation Company was liquidated.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Use of Estimates

The preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

(b) Reclassifications

Prior year amounts have been reclassified where necessary to conform to the 2010 presentation.

(c) Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

(d) Accounting for Regulated Operations

The Partnership's natural gas pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (NGA) of 1938 and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 980, *Regulated Operations*, provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. As of December 31, 2010 and 2009, there are no significant regulatory assets or liabilities reflected in these consolidated financial statements.

(e) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Partnership maintains an allowance for doubtful accounts for estimated losses on accounts receivable and for natural gas imbalances due from shippers and operators if it is determined the Partnership will not collect all or part of the outstanding receivable balance. The Partnership regularly reviews its allowance for doubtful accounts and establishes or adjusts the allowance as necessary using the specific-identification method. Account balances are written off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. Accounts written off for 2010 and 2009 were not material to the Partnership's consolidated financial statements.

(f) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in-kind, subject to the terms of the Partnership's tariff.

Imbalances due from others are reported on the consolidated balance sheets as trade accounts receivable or accounts receivable from affiliates. Imbalances owed to others are reported on the consolidated balance sheets as trade accounts payable or accounts payable to affiliates. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(g) Material and Supplies

The Partnership's inventory consists of materials and supplies. The materials and supplies are valued at cost with cost determined using the average cost method.

On December 1, 2010, the Partnership changed its method of valuing its materials and supplies to the average cost method from the lower of cost or market value method as used in prior periods. The Partnership believes the average cost method is a better representation of accounting for materials and supplies inventory described in the FERC Code of Federal Regulations. The change resulted in a $1.2 million decrease to operations and maintenance expense in 2010 on the Partnership's consolidated statements of income. There was no impact to the Partnership's cash flows.

(h) Property, Plant, and Equipment

Property, plant, and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs are capitalized, such as labor and materials, and indirect costs, such as overhead and interest. The Partnership capitalizes major units of property replacements or improvements and expenses minor items.

The Partnership uses the composite (group) method to depreciate property, plant, and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The depreciation rate is applied to the total cost of the group until its net book value equals its salvage value. All asset groups are depreciated using the FERC depreciation rates. Effective May 1, 2010 the Partnership's principal operating assets, which comprise approximately 94.30% of total property, plant, and equipment, are depreciated at an annual rate of 1.48%. The remaining assets are depreciated at annual rates ranging from 2.30% to 20.00%. Using these rates, the remaining depreciable life of these assets ranges from 1 to 42 years.

When property, plant, and equipment are retired, the Partnership charges accumulated depreciation and amortization for the original cost of the assets in addition to the cost to remove, sell, or dispose of the assets, less their salvage value. The Partnership does not recognize a gain or loss unless an entire operating unit is sold or retired. The Partnership includes gains or losses on dispositions of operating units in income.

The Partnership capitalizes a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC). AFUDC is calculated based on the Partnership's average cost of debt and equity. Debt amounts capitalized were $0.1 million for each of the years 2010 and 2009. These amounts are included as a reduction of interest and debt expense in the consolidated statements of income. Equity amounts capitalized during the years ended December 31, 2010 and 2009 were $0.2 million and $0.1 million, respectively. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the consolidated balance sheets.

(i) Revenue Recognition

The Partnership's revenues are primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For the Partnership's transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. For interruptible or volumetric-based services, the Partnership records revenues when physical deliveries of natural gas and other commodities are made at the agreed-upon delivery point. The Partnership does not take ownership of the gas that it transports. The Partnership is subject to FERC regulations, and as a result, revenues the Partnership collects may be subject to refund in a rate proceeding. The Partnership establishes reserves for these potential refunds.

(j) Commitments and Contingencies

Accounting for Asset Retirement Obligations

To the extent a legal obligation exists, the Partnership records a liability associated with the removal and retirement of its long-lived assets. Asset retirement liabilities are based on an estimate of the timing and amount of their settlement. They are recorded at their estimated fair value with a corresponding increase to property, plant, and equipment. This increase in property, plant, and equipment is then depreciated over the useful life of the long-lived asset to which the liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which is recorded as accretion expense in the consolidated statements of income.

Other Contingencies

The Partnership recognizes liabilities for contingencies when it has an exposure that, when fully analyzed, indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, the Partnership accrues a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the lower end of the range is accrued.

(k) Income Taxes

The Michigan Business Tax (MBT), effective January 1, 2008, 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.

3. MICHIGAN BUSINESS TAX

The Partnership files the MBT return on a combined 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.

MBT for the years ended December 31, 2010, 2009, and 2008 consists of the following:

(In Thousands)	**2010**	2009	2008
Current	**$3,474**	4,007	3,576
Deferred	**1,816**	1,410	1,927
	$5,290	5,417	5,503

The deferred tax liabilities as of December 31, 2010 and 2009 are as follows:

(In Thousands)	**2010**	2009
Deferred tax liabilities – utility plant	**$5,041**	3,280
Deferred tax liabilities – other	**128**	57
Net deferred tax liability	**$5,169**	3,337

As of December 31, 2010 and 2009, no valuation allowance is required.

4. COMMITMENTS AND CONTINGENCIES

(a) Legal Proceedings

The Partnership and its affiliates are named as defendants in legal proceedings that arise in the ordinary course of the Partnership's business. For each of the Partnership's legal matters, the Partnership evaluates the merits of the case, the Partnership's exposure to the matter, possible legal or settlement strategies, and the likelihood of an unfavorable outcome. If the Partnership determines that an unfavorable outcome is probable and can be estimated, the Partnership establishes the necessary accruals. As further information becomes available, or other relevant developments occur, the Partnership may accrue amounts accordingly. While there are still uncertainties related to the ultimate costs the Partnership may incur, based upon the Partnership's evaluation and experience to date, the Partnership had no accruals for its outstanding legal matters at December 31, 2010.

(b) Regulatory Matters

On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 (November 2009 Order) instituting an investigation pursuant to Section 5 of the NGA (GL Rate Proceeding). The FERC alleged, based on a review of certain historical information, that the

Partnership's revenues might substantially exceed the Partnership's actual cost of service and, therefore, may be unjust and unreasonable. On February 4, 2010, the Partnership filed a cost and revenue study in response to the November 2009 Order.

On May 21, 2010, the Partnership filed a stipulation and agreement (GL Settlement) establishing the terms pursuant to which all matters in the GL Rate Proceeding would be resolved. On June 17, 2010, the Administrative Law Judge certified the GL Settlement as uncontested to the FERC for its approval. On July 15, 2010, the FERC approved the GL Settlement without modification. The GL Settlement was reached among the Partnership, active participants, and the FERC trial staff. As approved, the GL Settlement applies to all current and future shippers on the Partnership's system.

Under the terms of the GL Settlement, reservation rates on the Partnership's pipeline system were reduced by 8.00%, effective May 1, 2010. In addition, depreciation expense for the Partnership's transmission plant decreased from 2.75% to 1.48% per year. Other depreciation rates for the plant either decreased or remained unchanged. Long-haul reservation rates from the Partnership's western zone to its eastern zone declined by 8.00% from $0.338 per dekatherm to $0.311 per dekatherm and various short-haul firm paths experienced similar reductions. Effective June 1, 2010, rates for long-haul interruptible transportation services increased from $0.252 per dekatherm to $0.322 per dekatherm with similar increases occurring on various short-haul paths. All other terms of the GL Settlement were effective May 1, 2010.

The Partnership's obligation to share interruptible transportation revenues as established under the September 24, 1992 Stipulation and Agreement in Partial Settlement of Rate Proceedings in FERC Docket No. RP91-143 was eliminated under the GL Settlement, effective May 1, 2010. On July 1, 2010, the Partnership paid out the interruptible transportation revenue sharing accumulated prior to May 1, 2010 and filed its final interruptible transportation revenue sharing report with the FERC in Docket No. RP91-143-061. Under the GL Settlement, the Partnership has agreed to a new revenue sharing provision with respect to jurisdictional revenues, including firm and interruptible transportation revenues, it receives in excess of $500 million during the period between November 1, 2010 and October 31, 2012. The Partnership will share with qualifying shippers 50% of any qualifying revenues collected during this period in excess of the $500 million threshold.

The GL Settlement rates will remain in effect through at least November 30, 2011. The GL Settlement includes a moratorium on participants and customers filing any NGA Section 5 rate case to place new rates into effect prior to November 1, 2012. There is also a moratorium on the Partnership filing a general NGA Section 4 rate case prior to June 1, 2011 to place new rates into effect prior to December 1, 2011. These moratoria are subject to conditions detailed in the GL Settlement. In addition, the GL Settlement requires the Partnership to file a NGA Section 4 general rate case no later than November 1, 2013.

(c) Environmental Matters

By letter dated December 28, 2009, the U.S. Environmental Protection Agency (EPA) required the Partnership to provide information regarding its natural gas compressor stations in the states of Minnesota, Wisconsin, and Michigan as part of the EPA's review of the Partnership's compliance with the Clean Air Act. On May 28, 2010, the Partnership submitted its final response to the EPA. To date, the Partnership has received one request from the EPA for clarification regarding submitted information. The potential effects on the Partnership that may arise as a result of this information request are not determinable at this time.

(d) Asset Retirement Obligations

The Partnership has determined it has legal obligations associated with its natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. The Partnership is also required to operate and maintain its natural gas pipeline system, and intends to do so as long as supply and demand for natural gas exists, which the Partnership expects for the foreseeable future. Therefore, the Partnership believes its natural gas pipeline system assets have indeterminate lives and, accordingly, has recorded no asset retirement liabilities as of December 31, 2010 and 2009. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(e) Other Commercial Commitments

The Partnership holds cancelable easements or rights-of-way arrangements from landowners permitting the use of land for the construction and operation of the Partnership's pipeline system. Currently, the Partnership's obligations under these easements are not material to its results of operations.

5. LONG-TERM DEBT

The Partnership's long-term debt outstanding consisted of the following at December 31:

(In Thousands)	**2010**	2009
8.74% series Senior Notes due 2011	**$10,000**	20,000
6.73% series Senior Notes due 2011 to 2018	**72,000**	81,000
9.09% series Senior Notes due 2012 to 2021	**100,000**	100,000
6.95% series Senior Notes due 2019 to 2028	**110,000**	110,000
8.08% series Senior Notes due 2021 to 2030	**100,000**	100,000
	392,000	411,000
Less current maturities	**19,000**	19,000
Total long-term debt less current maturities	**$373,000**	392,000

The aggregate annual required repayment of long-term debt is $19.0 million for each year from 2011 through 2015.

The Partnership is required to comply with certain financial, operational, and legal covenants. Under the most restrictive covenants in the Senior Note Agreements, approximately $211.0 million of partners' capital was restricted as to distributions as of December 31, 2010. As of December 31, 2010, management of the Partnership believes the Partnership was in compliance with all of its financial covenants.

6. FAIR VALUE MEASUREMENTS

(a) Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Partnership's financial instruments that are measured on a recurring basis at December 31, 2010 and 2009. The fair value of a financial instrument is the amount 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.

	2010		2009	
(In Thousands)	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Financial assets:				
Cash and cash equivalents	**$40**	**40**	125	125
Financial liabilities:				
Long-term debt	**$392,000**	**518,199**	411,000	506,248

The following methods and assumptions were used to estimate the fair value of each class of financial instruments measured on a recurring basis:

Cash and cash equivalents – The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

Long-term debt – The fair value of senior notes was estimated based on quoted market prices for the same or similar debt instruments with similar terms and remaining maturities, which is classified as Level 2 in the fair value hierarchy, where the fair value is determined by using valuation techniques that refer to observable market data. The Partnership presently intends to maintain the current schedule of maturities for the note, which will result in no gains or losses on its repayment.

(b) Fair Value Hierarchy

Under FASB ASC 820, *Fair Value Measurements and Disclosures*, fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Partnership has the ability to access at the measurement date.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

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.

7. TRANSACTIONS WITH AFFILIATED COMPANIES

(a) Cash Management Program

The Partnership participates in TransCanada's cash management program, which matches short-term cash surpluses and needs of participating affiliates, thus minimizing total borrowings from outside sources. Monies advanced under the agreement are considered to be a loan, accruing interest and repayable on demand. At December 31, 2010 and 2009, the Partnership had a cash pool receivable from TransCanada PipeLine USA Ltd. of $44.9 million and $34.0 million, respectively. The interest rate on the cash pool at December 31, 2010 and 2009 was 0.51% and 0.40%, respectively.

(b) Affiliate Revenues and Expenses

The Partnership provides natural gas transportation services to TransCanada affiliates in the normal course of business. Affiliated transportation revenues are primarily provided under fixed priced contracts with remaining terms ranging from one to eight years.

The Partnership's largest shipper, TransCanada PipeLines Limited, has 576 MDth/d of long haul capacity under contract expiring on October 31, 2011. Negotiations are currently in progress related to these contracts.

Pursuant to the Partnership's Operating Agreement, day-to-day operation of partnership activities is the responsibility of the Company. The Partnership is charged by the Company and affiliates for services such as legal, tax, treasury, human resources, other administrative functions, and for other costs incurred on its behalf. These include, but are not limited to, employee benefit costs and property and liability insurance costs. These costs are based on direct assignment to the extent practicable, or by using allocation methods that are reasonable reflections of the utilization of services provided to or for the benefits received by the Partnership. In addition, the Partnership charges rent to affiliates for use of office space in Troy, Michigan.

The following table shows revenues and charges from the Partnerships' affiliates for the periods ended December 31:

(In Thousands)	**2010**	2009	2008
Transportation revenues from affiliates	**$148,464**	141,721	143,705
Rental revenue from affiliate	**884**	643	432
Costs charged from affiliates	**30,282**	33,765	34,261

8. DISTRIBUTIONS

The Partnership's distribution policy generally results in a quarterly cash distribution equal to 100% of distributable cash flow based upon earnings before income taxes, depreciation, and AFUDC, less capital expenditures and debt repayments not funded with cash calls to its partners, and current MBT. The resulting distribution amount and timing are subject to Management Committee modification and approval after considering business risks as well as ensuring minimum cash balances, equity balances, and ratios are maintained.

In September 2010, the Partnership's distribution policy was changed to allow distributable cash flow to include debt repayments funded with partner cash calls. Previous distributable cash flow included a deduction for debt repayments without considering partner cash call funding.

On January 11, 2011, the Management Committee of the Partnership declared a cash distribution in the amount of $36.3 million to the partners. The distribution was paid on February 1, 2011.

9. SUBSEQUENT EVENTS

Subsequent events have been assessed through February 10, 2011, which is the date the consolidated financial statements were issued, and we concluded there were no events or transactions during this period that would require recognition or disclosure in the consolidated financial statements other than those already reflected.

NORTHERN BORDER PIPELINE COMPANY
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, 2010 and 2009, 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, 2010. 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 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 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, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 10, 2011

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, (In thousands)	**2010**	2009
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 10,231**	$ 16,864
Accounts receivable	**31,129**	23,843
Related party receivables	**276**	391
Materials and supplies, at cost	**4,310**	4,471
Prepaid expenses and other	**1,307**	1,572
Total current assets	**47,253**	47,141
Property, plant and equipment:		
In service natural gas transmission plant	**2,508,512**	2,513,825
Construction work in progress	**8,567**	813
Total property, plant and equipment	**2,517,079**	2,514,638
Less: Accumulated provision for depreciation and amortization	**1,222,259**	1,171,544
Property, plant and equipment, net	**1,294,820**	1,343,094
Other assets:		
Regulatory assets	**20,315**	20,027
Unamortized debt expense	**2,573**	2,791
Other	**22**	1,339
Total other assets	**22,910**	24,157
Total assets	**$1,364,983**	$1,414,392
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	**$10,525**	3,409
Related party payables	**3,015**	3,390
Accrued taxes other than income	**22,976**	22,713
Accrued interest	**7,044**	7,058
Other	**3,178**	1,389
Total current liabilities	**46,738**	37,959
Long-term debt, net of current maturities	**540,574**	564,549
Deferred credits and other liabilities:		
Related party payables	**–**	753
Regulatory liabilities	**9,649**	7,189
Other	**–**	396
Total deferred credits and other liabilities	**9,649**	8,338
Commitments and contingencies		
Partners' equity:		
Partners' capital	**770,905**	806,600
Accumulated other comprehensive loss	**(2,883)**	(3,054)
Total partners' equity	**768,022**	803,546
Total liabilities and partners' equity	**$1,364,983**	$1,414,392

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

Years Ended December 31, (In thousands)	**2010**	2009	2008
Operating revenue	**$295,069**	$249,217	$293,105
Operating expenses:			
Operations and maintenance	**49,720**	48,695	51,260
Depreciation and amortization	**61,470**	61,870	61,081
Taxes other than income	**24,268**	22,103	26,765
Operating expenses	**135,458**	132,668	139,106
Operating income	**159,611**	116,549	153,999
Interest expense:			
Interest expense	**26,649**	36,750	40,974
Interest expense capitalized	**(60)**	(137)	(182)
Interest expense, net	**26,589**	36,613	40,792
Other income (expense):			
Allowance for equity funds used during construction	**148**	235	323
Gain on sale of assets	**–**	–	16,166
Other income	**3,165**	2,309	2,932
Other expense	**(86)**	(348)	(426)
Other income, net	**3,227**	2,196	18,995
Net income to partners	**$136,249**	$ 82,132	$132,202

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (In thousands)	**2010**	2009	2008
Net income to partners	**$136,249**	$82,132	$132,202
Other comprehensive income:			
Changes associated with hedging transactions	**171**	2,654	(3,267)
Total comprehensive income	**$136,420**	$84,786	$128,935

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

Years Ended December 31, (In thousands)	**2010**	2009	2008
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	**$136,249**	$ 82,132	$ 132,202
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	**61,556**	62,218	61,464
Allowance for equity funds used during construction	**(148)**	(235)	(323)
Changes in components of working capital	**2,034**	(25)	(4,827)
Gain on sale of assets	**–**	–	(16,166)
Other	**(519)**	(4,084)	(2,940)
Total adjustments	**62,923**	57,874	37,208
Net cash provided by operating activities	**199,172**	140,006	169,410
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	**(9,861)**	(11,090)	(20,538)
Investments in other assets	**–**	–	(3,834)
Proceeds from sale of assets	**–**	–	20,000
Net cash used in investing activities	**(9,861)**	(11,090)	(4,372)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	**–**	84,550	–
Distributions to partners	**(171,944)**	(151,458)	(181,320)
Issuance of debt	**97,000**	214,000	145,000
Retirement of debt	**(121,000)**	(280,000)	(130,000)
Debt financing costs	**–**	(799)	–
Net cash used in financing activities	**(195,944)**	(133,707)	(166,320)
Net change in cash and cash equivalents	**(6,633)**	(4,791)	(1,282)
Cash and cash equivalents at beginning of year	**16,864**	21,655	22,937
Cash and cash equivalents at end of year	**$ 10,231**	$ 16,864	$ 21,655
Supplemental disclosure for cash flow information:			
Cash paid for interest, net of amount capitalized	**$ 26,137**	$ 40,987	$ 41,868
Changes in components of working capital:			
Accounts receivable	**$ (7,286)**	$ 8,938	$ (1,474)
Related party receivables	**115**	(5)	2,368
Materials and supplies	**161**	91	(357)
Prepaid expenses and other	**265**	1,735	(680)
Accounts payable	**7,116**	(2,687)	(1,084)
Related party payables	**(375)**	(462)	(2,000)
Accrued taxes other than income	**263**	(3,567)	(1,345)
Accrued interest	**(14)**	(4,002)	(223)
Other current liabilities	**1,789**	(66)	(32)
Total	**$ 2,034**	$ (25)	$ (4,827)

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CHANGES IN PARTNERS' EQUITY

(In thousands)	TC PipeLines Intermediate Limited Partnership	ONEOK Partners Intermediate Limited Partnership	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
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
Net income to partners	41,066	41,066	–	82,132
Changes associated with hedging transactions	–	–	2,654	2,654
Equity contributions received	42,275	42,275	–	84,550
Distributions paid	(75,729)	(75,729)	–	(151,458)
Partners' equity at December 31, 2009	403,300	403,300	(3,054)	803,546
Net income to partners	68,124	68,125	–	136,249
Changes associated with hedging transactions	–	–	171	171
Distributions paid	(85,972)	(85,972)	–	(171,944)
Partners' equity at December 31, 2010	**$385,452**	**$385,453**	**$(2,883)**	**$ 768,022**

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

NORTHERN BORDER PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

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

We are a Texas general partnership formed in 1978. We own a 1,398-mile natural gas transmission pipeline system, which includes an additional 149 pipeline miles parallel to the original 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, 2010 and 2009 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.

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 Financial Accounting Standards Board Accounting Standards Codification (ASC) 980, *Regulated Operations*. Accordingly, certain assets and liabilities that result from the regulated ratemaking process are reflected on the balance sheets as regulatory assets and regulatory liabilities.

The following table presents a summary of regulatory assets, net of amortization, at December 31, 2010 and 2009:

	December 31,		Remaining recovery/ settlement period
	2010	2009	
	(In thousands)		*(Years)*
Fort Peck lease option	**$14,457**	$13,273	40
Pipeline extension project	**5,075**	5,536	11
Unamortized loss on reacquired debt	**–**	44	–
Deferred rate case expenditures	**783**	1,174	2
Total regulatory assets	**$20,315**	$20,072	

At December 31, 2010 and 2009, respectively, we have reflected a regulatory liability of $9.6 million and $7.2 million on the balance sheets, related to negative salvage accrued for estimated net costs of removal of transmission plant. The settlement period for negative salvage value is related to the estimated life of the assets. 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 ASC 980, which includes such factors as regulatory changes and the impact of competition. Our review of these criteria currently supports the continuing application of ASC 980. If we cease to meet the criteria of ASC 980, a write-off of related regulatory assets and liabilities could be required.

Revenue Recognition

Our revenues are primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For our transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. We do not take ownership of the gas that is transported. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas and other commodities are made at the agreed-upon delivery point. We are subject to FERC regulations, and as a result, revenues we collect may be subject to refund in a rate proceeding. We establish reserves for these potential refunds.

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.

Materials and Supplies

Materials and supplies are valued at cost with cost determined using the average cost method.

Property, Plant and Equipment and Related Depreciation and Amortization

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

Maintenance and repairs are charged to operations in the period incurred. The provision for depreciation and amortization of the transmission line is an integral part of our FERC tariff. As a result of the settlement of our 2005 rate case, the effective depreciation rate applied to our transmission plant is 2.40 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. Composite rates are applied to all other functional groups of property having similar economic characteristics.

Asset Retirement Obligation

The fair value of a liability for an asset retirement obligation is recorded 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 differs from the amount of natural gas scheduled to be delivered or received. We value these imbalances due to or from shippers and interconnecting parties at current 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. In addition, we classify all imbalances as current as we expect to settle them within a year.

Risk Management

We utilize financial instruments to reduce our market risk exposure to interest rate fluctuations and achieve a more predictable cash flow. We follow established policies and procedures to assess risk and approve, monitor and report our financial instrument activities. We do not use these instruments for trading purposes. All derivative instruments (including certain derivative instruments embedded in other contracts) are 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).

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.

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. We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

Reclassifications

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

3. 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.

Effective January 1, 2007, we implemented new rates as a result of the settlement of our 2005 rate case. For the full transportation route from Port of Morgan, Montana to the Chicago area, our transportation rate is approximately $0.44 per Dekatherm (Dth), which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. 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 an other current liability or a current asset classified as prepaid expense and other, respectively, on the balance sheets. The compressor usage surcharge rate is adjusted annually. The current liability or current asset will reflect the net over or under recovery of actual compressor usage related costs at the date of the balance sheet. As of December 31, 2010, we had recorded $2.3 million as another current liability on the accompanying balance sheet for the net over recovery of compressor usage related costs. As of December 31, 2009, $0.1 million as prepaid expense and other assets on the accompanying balance sheet for the net under recovery of compressor usage related costs.

4. MAJOR CUSTOMERS

For the year ended December 31, 2010, shippers providing significant operating revenues were Tenaska Marketing Ventures and BP Canada Energy Marketing Corp. (BP Canada) with revenues of $43.3 million and $41.2 million, respectively. For the year ended December 31, 2009, shippers providing significant operating revenues were BP Canada and Tenaska Marketing Ventures with revenues of $41.9 million and $26.7 million, respectively. For the year ended December 31, 2008, shippers providing significant operating revenues were BP Canada and Cargill Inc. (Cargill) with revenues of $38.8 million and $32.4 million, respectively.

5. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

December 31, (In thousands)	**2010**	2009
2007 Credit Agreement – average interest rate of 0.54% and 0.52% at December 31, 2010 and 2009, respectively, due 2012	**$191,000**	$215,000
2001 Senior Notes – 7.50%, due 2021	**250,000**	250,000
2009 Senior Notes – 6.24%, due 2016	**100,000**	100,000
Unamortized debt discount	**(426)**	(451)
Subtotal	**540,574**	564,549
Current maturities	**–**	–
Long-term debt	**$540,574**	$564,549

On August 26, 2009, we issued $100 million of 6.24 percent Senior Notes due August 26, 2016. The proceeds of the 6.24 percent Senior Notes along with equity contributions, borrowings under the revolving credit agreement and cash generated by operating activity was used to repay $200 million of 7.75 percent Senior Notes due September 1, 2009.

At December 31, 2010, based on the principal commitment amount of $250 million, available capacity under the 2007 Credit Agreement was $59 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 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. Under the 2009 Senior Notes, we may not at any time permit debt secured by liens to exceed 20 percent of partners capital and may not permit total debt, at any time, to exceed 70 percent of total capitalization. At December 31, 2010, we were in compliance with all of our financial covenants.

Aggregate required repayment of long-term debt for the next five years is $191 million in 2012. Aggregate required repayments of long-term debt thereafter total $350 million. There are no required repayment obligations for 2011, 2013, 2014 or 2015.

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

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.

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. No amounts were recognized in income due to hedge ineffectiveness of the Collar Agreement.

The following table represents the unrealized (gains) losses recorded in accumulated other comprehensive income (loss) on the statements of changes in partners' equity:

	Years Ended December 31,		
Derivatives under Cash Flow Hedging Relationships	**2010**	2009	2008
	(In thousands)		
Cash flow hedges	**$ –**	$(3,633)	$1,781

We record in accumulated other comprehensive income (loss) amounts received or paid related to terminated interest rate swap agreements for cash flow hedges and amortize these amounts to interest expense. The following table represents the effective portion of realized gains, net of realized losses, that have been reclassified from accumulated other comprehensive income (loss) and recognized as a reduction (increase) to interest expense on the statements of income:

		Years Ended December 31,		
Net Gain Reclassified from AOCI into Income (Effective Portion)	Statements of Income Caption	**2010**	2009	2008
		(In thousands)		
Cash flow hedges	Interest expense	**$(171)**	$979	1,486

At December 31, 2010, we have realized losses recorded in accumulated other comprehensive loss of approximately $2.9 million. We expect to reclassify approximately $0.2 million from accumulated other comprehensive loss as an increase to interest expense in 2011.

7. FAIR VALUE MEASUREMENTS

Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2010 and 2009. The fair value of a financial instrument is the amount 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.

	2010		2009	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	**$10,231**	**$10,231**	$16,864	$16,864
Financial liabilities:				
Long-term debt	**$540,574**	**$599,381**	$564,549	$612,009

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and cash equivalents – The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

Long-term debt – The fair value of our senior notes were estimated based on quoted market prices for similar debt instruments with similar terms and remaining maturities, which is classified as Level 2 in "Fair Value Hierarchy," where the fair value is determined by using valuation technique that refers to observable market data. We presently intend to maintain the current schedule of maturities for the 2001 and 2009 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.

Fair Value Hierarchy

Under ASC 820, *Fair Value Measurements and Disclosures,* fair value measurements are characterized in one of three levels based upon the input used to arrive at the measurement. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access at the measurement date.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

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.

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, 2010, 2009 and 2008 were $1.4 million, $1.4 million and $2.5 million, respectively. Our future minimum lease payments, which assume we have exercised the option to renew a pipeline right-of-way lease in April 2011 for a term of 25 years (discussed below), are as follows:

Year ending December 31, (In thousands)	
2011	$1,917
2012	1,918
2013	1,896
2014	1,889
2015	1,889
Thereafter	55,406
	$64,915

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 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 through March 31, 2036.

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. Amounts related to this obligation are included in related party payables on the balance sheets. Future remaining payments for this obligation are as follows:

Year ending December 31, (In thousands)	
2011	$753

Environmental Matters

On February 2, 2009, we received a Notice of Violation (NOV) from the U.S. Environmental Protection Agency (EPA) alleging that we were in violation of certain regulations pursuant to the Clean Air Act (CAA) regarding a compressor station on our system. On April 1, 2010, we received indication from the EPA that it does not intend to file a complaint against us with respect to the NOV. We expect no further action from the EPA regarding this NOV.

Other

As of December 31, 2010, we have made commitments of $0.3 million in connection with construction of the Princeton Lateral 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. In addition, any inability to refinance maturing debt will be funded by equity contributions. 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.

For the years ended December 31, 2010, 2009 and 2008, we paid distributions to our general partners of $171.9 million, $151.5 million and $181.3 million, respectively. In 2009, we received contributions from our general partners in the amount of $84.6 million. During the first quarter of 2009, we received $8.6 million, which was used to fund 50 percent of the costs of construction of the Des Plaines Project. During the third quarter of 2009, we received $76 million, which was used for the retirement of the 7.75 percent Senior Notes due September 1, 2009.

Northern Border's distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by its Management Committee to establish the timing and amount of required equity contributions. In accordance with this policy, we currently estimate an equity contribution in 2011 of approximately $107.5 million.

10. 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 TransCanada Northern Border and us 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, 2010, 2009 and 2008, our charges from TransCanada and its affiliates totaled approximately $25.8 million, $25.5 million and $28.6 million, respectively.

For the years ended December 31, 2010, 2009 and 2008, 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 2010, 2009 and 2008 was $4.1 million, $4.2 million and $5.0 million, respectively. At December 31, 2010 and 2009, we had outstanding receivables from ONEOK Energy of $0.3 million and $0.4 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 pipeline system that extends 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. The Bison Pipeline was placed into service in January 2011.

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 entered into an interconnect agreement with ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada. The interconnect agreement 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.

In April 2010, Northern Border and Bison entered into an Interconnect Agreement in which Bison paid $1.4 million for the estimated costs of the interconnect at Northern Border Compressor Station No. 6. The project was completed in the fourth quarter of 2010.

11. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $51.5 million was declared and paid on February 1, 2011 for the fourth quarter of 2010.

We have evaluated subsequent events through February 10, 2011, which represents the date the financial statements were issued and concluded there were no events or transactions during this period that would require recognition or disclosure in the financial statements other than those already reflected.

Glossary

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

Acquisition Agreement	Agreement for Purchase and Sale of Membership Interest for the Partnership's purchase of North Baja
ANR	ANR Pipeline Company
ASC	Accounting Standards Codification
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BIA	Bureau of Indian Affairs
Bison	Bison Pipeline LLC
CAA	Clean Air Act
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Collar Agreement	Northern Border's interest rate collar agreement
Costa Azul	Energia Costa Azul
CWA	Clean Water Act
Delaware Act	Delaware Revised Uniform Limited Partnership Act
Design capacity	Pipeline capacity available to transport natural gas based on system facilities and design conditions
Dth	Dekatherms
EBITDA	Net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges
EPNG	El Paso Natural Gas Company
EPA	U.S. Environmental Protection Agency
Essar	Essar Steel Minnesota LLC
Exchange Agreement	Agreement with the General Partner pursuant to which the Partnership issued new common units to the General Partner and provided for Revised IDRs in exchange for the cancellation of the Old IDRs
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Gas exiting the WCSB	Net of the supply of and demand for natural gas in the WCSB region that is available for transportation to downstream markets; where supply represents WCSB production adjusted for injections into and withdrawals from WCSB storage
General Partner	TC PipeLines GP, Inc.
GL Rate Proceeding	FERC investigation into Great Lakes' rates pursuant to Section 5 of the NGA
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest Corporation
HCAs	High consequence areas
IDRs	Incentive Distribution Rights
INGAA	Interstate Natural Gas Association of America
IRS	Internal Revenue Service

IT	Interruptible Transportation
LIBOR	London Interbank Offered Rate
LNG	Liquified Natural Gas
MDth/d	Thousand dekatherms per day
MLP	Master Limited Partnership
MMcf/d	Million cubic feet per day
MMDth/d	Million dekatherms per day
NEB	National Energy Board of Canada
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
November 2009 Order	FERC order issued in FERC Docket No. RP10-149 on November 19, 2009 instituting GL Rate Proceeding
Offering	The sale of 2,609,680 newly issued, unregistered common units representing limited partner interests in the Partnership to TransCan Northern at a price per common unit of $30.042 for an aggregate amount of approximately $78.4 million
Old IDRs	IDRs available to the General Partner under the Amended and Restated Agreement of Limited Partnership
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners GP	ONEOK Partners GP, LLC
Other Pipes	North Baja and Tuscarora
Our pipeline systems	Great Lakes, Northern Border, North Baja and Tuscarora
Partnership	TC PipeLines, LP and its subsidiaries
Partnership Agreement	Second Amended and Restated Agreement of Limited Partnership
PCBs	Polychlorinated biphenyls
Pipeline Safety Act	The Pipeline Safety Improvement Act of 2002
RCRA	Resource Conservation and Recovery Act
Revised IDRs	IDRs available to the General Partner under the Second Amended and Restated Agreement of Limited Partnership
ROE	Return on equity
Ruby	Ruby Pipeline LLC
S&P	Standard & Poor's
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP's revolving credit and term loan agreement
Tortoise	Tortoise Capital Advisors, L.L.C.
TransCan Northern	TransCan Northern Ltd.
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin
Yuma Lateral	An expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma City, Arizona

Board of Directors of the General Partner of TC PipeLines, LP

Gregory A. Lohnes, Chairman, TC PipeLines GP, Inc.
President, Natural Gas Pipelines
TransCanada Corporation
Calgary, Alberta

Steven D. Becker, President, and Director TC PipeLines GP, Inc
Vice-President, Business Development, Natural Gas Pipelines
TransCanada Corporation
Calgary, Alberta

Kristine L. Delkus
Deputy General Counsel, Pipelines and Regulatory Affairs,
Pipelines Division
TransCanada Corporation
Calgary, Alberta

Jack F. Jenkins-Stark (1) (2) (3)
Chief Financial Officer
BrightSource Energy, Inc.
Oakland, California

James (Jim) M. Baggs
Vice-President, Operations and Engineering
TransCanada Corporation
Calgary, Alberta

David L. Marshall (4) (5)
Retired Vice-Chairman and Chief Financial Officer
The Pittston Company
Sparks, Nevada

Walentin (Val) Mirosh (3) (5)
President
Mircan Resources Ltd.
Calgary, Alberta

(1) Lead Director
(2) Chair, Conflicts Committee
(3) Member, Audit Committee
(4) Chair, Audit Committee
(5) Member, Conflicts Committee

Executive Officers of the General Partner of TC PipeLines, LP

Gregory A. Lohnes
Chairman

Steven D. Becker
President

Terry C. Ofremchuk
Vice-President, Taxation

Rhonda L. Amundson
Treasurer

Robert C. Jacobucci
Principal Financial Officer and Controller

Donald J. DeGrandis
Secretary

Annie C. Belecki
Assistant Secretary

Stephanie E. Wilson
Vice-President, Commercial

Stuart P. Kampel
Vice-President, Business Development

TC PipeLines, LP

13710 FNB Parkway
Omaha, NE 68154-5200
Telephone 877.290.2772 Facsimile 508.871.7047

450 First Street SW
Calgary, Alberta, Canada T2P 5H1
Telephone 877.290.2772 Facsimile 403.920.2457

Investor Relations

Lee Evans
Manager, Investor Relations

Telephone 877.290.2772 Facsimile 403.920.2457
E-mail: investor_relations@tcpipelineslp.com

Website

www.tcpipelineslp.com

K-1 Information

Telephone 877.699.1091

Stock Exchange Listing

NASDAQ Global Market: TCLP

Auditors

KPMG LLP, Calgary, Alberta, Canada

Transfer Agent

BNY Mellon Shareowner Services
Telephone 800.756.3353

Mailing Address
P.O Box 358015
Pittsburgh, PA 15252-8015

Courier Address
500 Ross Street, 6th Floor
Pittsburgh, PA 15262

Please recycle

TC PipeLines, LP