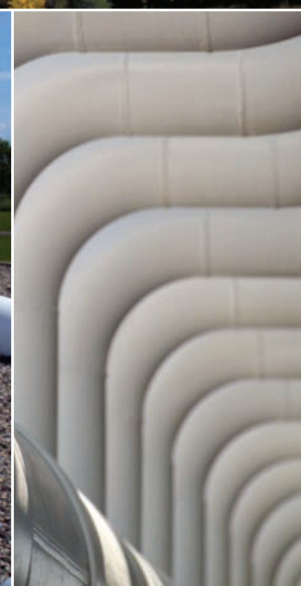
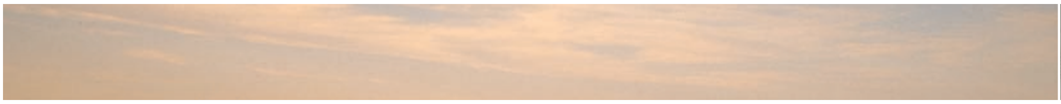
2011 | ANNUAL REPORT



Solid Foundations | Positioned for Growth

TC PipeLines, LP




SOLID FOUNDATIONS



With over 5,550 miles of pipelines, our portfolio of assets generates cash flow from six critical Federal Energy Regulatory Commission (FERC) regulated natural gas pipelines where revenues are derived almost entirely from fee-based revenues with many under long term contracts.

STRONG FINANCIAL PERFORMANCE

TC PipeLines most significant achievement in 2011 was the $605 million acquisition back in May of 25% ownership interests in the Gas Transmission Northwest (GTN) and Bison pipelines from its sponsor, TransCanada Corporation (TransCanada). Both are underpinned by long term contracts. With the addition of GTN and Bison to the Partnership's existing portfolio, TC PipeLines grew its asset base by 26 per cent to $2.1 billion in 2011.

Strong financial performance in 2011 across all of our assets is evidence of the quality of our pipeline investments and the fundamentals that support them. Cash distributions paid increased 16 per cent to $155 million while distributable cash flow increased 23 per cent to $222 million creating a solid foundation for sustainable future cash distributions.

ESSENTIAL INFRASTRUCTURE

Northern Border and Great Lakes both contributed strong results for the Partnership in 2011. As one of the best transportation options for shippers to move gas out of the Western Canada Sedimentary Basin (WCSB), Northern Border's cash flows are supported by strong fundamentals and its long haul capacity is substantially contracted through March 2013. Great Lakes is critical to serving natural gas storage fields in Michigan and Southwestern Ontario in Canada. While current low gas prices and high storage levels create short-term uncertainties, Great Lakes remains critical and essential infrastructure that will be required to bring gas to its markets.

In the WCSB, our sponsor, TransCanada is committed to connecting new gas supplies from shale and deep gas sources into their Alberta System. Today TransCanada has approximately 3.4 Bcf/d of contractual commitments to bring this new gas to market by 2014 along with a significant amount of interest from producers for additional transportation services. Northern Border, Great Lakes and GTN are well positioned to transport these gas supplies.

ENHANCED STABILITY

The Partnership was successful in negotiating tariff rate settlements with its shippers for both GTN and Tuscarora in 2011. Long-term revenues and cash flow from these assets have been secured as a result of these settlements. GTN negotiated a four year settlement that mitigates the impact of increased pipeline competition into Northern California. GTN's new rates reflect its current contract levels of over 1.5 billion cubic feet per day and a lower annual depreciation rate which will increase the revenue stability of the asset in the future.

Tuscarora's settlement, which is currently pending FERC approval, reduces its annual revenues as a result of a lower tariff rate, reflecting its current rate base and a lower depreciation rate. The negotiated settlement added three year contract extensions with its largest shipper resulting in Tuscarora now being fully contracted through 2019. Both settlements effectively create increased cash flow certainty and add future stability to the Partnership's existing foundation of long term contracted assets. ■

POSITIONED FOR GROWTH

FINANCIAL STRENGTH & FLEXIBILITY

The Partnership had a very active year in terms of financing activities that were all aimed at bolstering its financial position. In May, we raised $338 million in a 7.3 million common unit equity offering, associated with the GTN and Bison transactions. We also raised another $350 million in long term debt in June after receiving an investment grade credit rating from Standard & Poor's and Moody's (BBB/Baa2), and refinanced and increased our line of credit back in July.

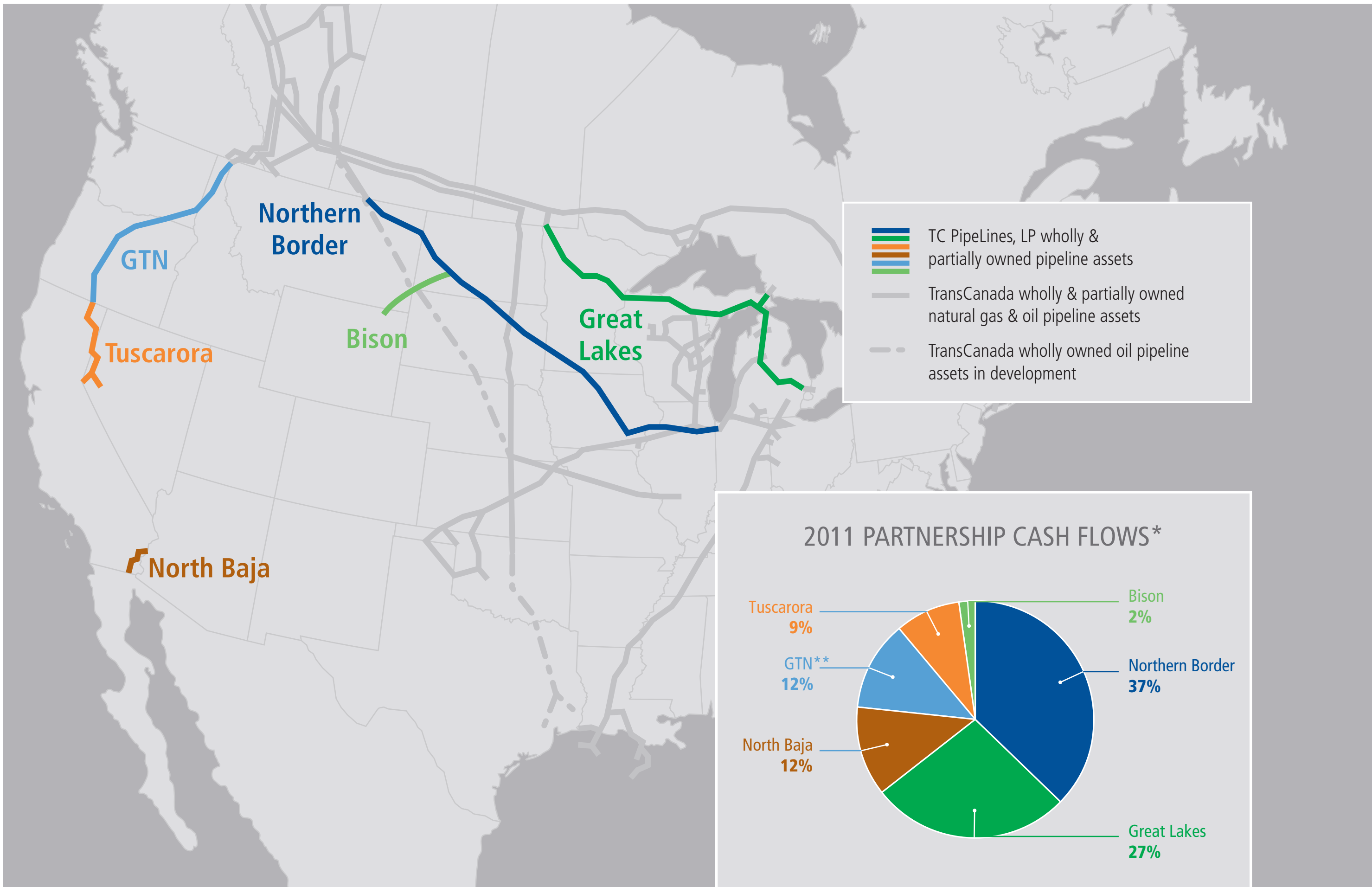
Our sound financial positioning is further supported with a cash distribution coverage ratio that was 1.31 times coverage in 2011, excluding a one time distribution of $20 million from GTN that was factored into its purchase price. With an ample amount of financial flexibility and liquidity that is coupled with low General Partner incentive distribution rights, currently set at two per cent, we are well positioned for future growth.

STRONG INDUSTRY SPONSOR

With over $49 billion in assets and 60 years of operating history, TransCanada is one of the largest energy infrastructure companies in North America. Our affiliation with TransCanada is one of our key strengths. With investments in natural gas pipelines and storage, oil pipelines and power generation, they provide us with industry insight and operating and management experience. With their 33 per cent ownership interest in TC PipeLines, TransCanada and our unitholders are aligned with our strategy to grow stable cash flows.

FUTURE OPPORTUNITIES

Future growth has the potential to come from multiple sources: drop-down opportunities from TransCanada, third-party acquisitions or organic expansion projects on our existing pipelines, all of which could ultimately support TC PipeLines' ability to provide growing and sustainable 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. Includes cash flows from GTN and Bison as of May 3, 2011, date of acquisition, to December 31, 2011.

** Includes $20 million one time cash distribution from GTN.

WEST COAST PIPELINE ASSETS

GTN

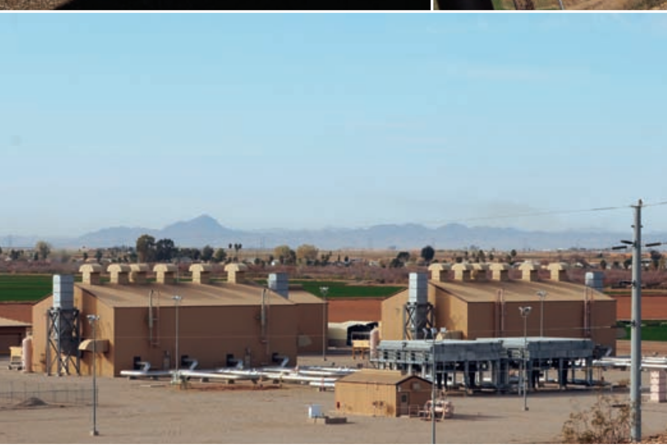
- Ownership: 25%
- Pipeline Length: 1,353 miles
- Pipeline Capacity: 2.9 Bcf/d
- Long-term contacts maturing between 2015 and 2023

TUSCARORA

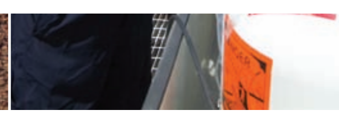
- Ownership: 100%
- Pipeline Length: 305 miles
- Pipeline Capacity: 0.2 Bcf/d
- Fully contracted through 2019

NORTH BAJA

- Ownership: 100%
- Pipeline Length: 86 miles, bi-directional
- Pipeline Capacity: 0.6 Bcf/d (northbound) and 0.5 Bcf/d (southbound)
- Long-term contacts maturing between 2022 and 2031



MID-WEST PIPELINE ASSETS



NORTHERN BORDER

- Ownership: 50%
- Pipeline Length: 1,407 miles
- Pipeline Capacity: 2.4 Bcf/d
- Substantially fully contracted through March 2013

BISON

- Ownership: 25%
- Pipeline Length: 303 miles
- Pipeline Capacity: 0.4 Bcf/d
- Fully contracted through 2020

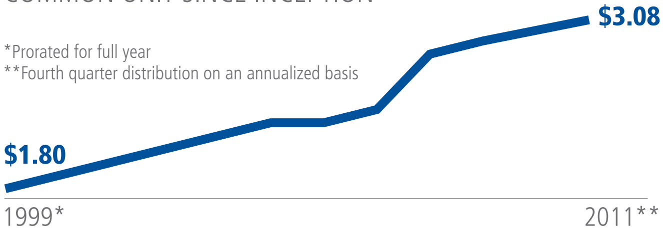
GREAT LAKES

- Ownership: 46.45%
- Pipeline Length: 2,115 miles
- Pipeline Capacity: 2.4 Bcf/d
- 75% contracted through October 2012

LETTER TO UNITHOLDERS

2011 was another solid year for TC PipeLines. We successfully executed on our strategy to invest in low-risk, long-life infrastructure by purchasing interests in two natural gas pipelines, both of which are supported by long term contracts. Through our disciplined investment approach, we were able to increase our cash distributions paid per common unit by 3.4 per cent furthering our 12 year track record of providing sustainable and growing cash distributions.

71% GROWTH IN ANNUAL CASH DISTRIBUTIONS PAID PER COMMON UNIT SINCE INCEPTION



YEAR IN REVIEW

TC PipeLines executed on several initiatives that are expected to deliver stable and sustainable cash distributions creating long-term value for our unitholders. In 2011, the Partnership:

- Increased cash distributions paid on a per unit basis by 3.4 per cent
- Acquired a 25 per cent interest in each of Gas Transmission Northwest (GTN) and Bison for $605 million
- Raised $338 million through an equity offering to finance the GTN and Bison acquisitions
- Obtained investment grade credit ratings (BBB/Baa2) and raised $350 million in our first public debt offering
- Enhanced our financial flexibility by expanding our credit facility to $500 million
- Negotiated rate case settlements for both GTN and Tuscarora
- Placed the Princeton lateral into service on Northern Border
- Moved our exchange listing to the New York Stock Exchange (NYSE) and changed our trading ticker symbol to 'TCP'

In May, we acquired a 25 per cent interest in each of the GTN and Bison pipelines from our sponsor, TransCanada. This acquisition creates greater diversification for the Partnership's overall asset portfolio. GTN has over 50 years of history of serving large utilities in California and the Pacific Northwest. The Bison pipeline adds a brand new asset to the Partnership's portfolio and adds a new supply basin that complements our Northern Border pipeline. Both are backed by long-term, fee-based contracts which are expected to increase the stability of revenues and cash flow to the Partnership's existing portfolio of strong assets.

FINANCIAL STRENGTH

TC PipeLines' financial results reflect strong performance from all of our assets. The Partnership earned $157 million or $3.02 per unit in 2011 compared to $137 million or $2.91 per unit in 2010. Partnership cash flows increased $42 million, or 23 percent to $222 million. Our 12 year track record of growing sustainable cash distributions continued this year as we increased our distributions to unitholders by $16 million to $155 million. Excluding the $20 million one time cash distribution from GTN, our cash distribution coverage ratio remained solid with 1.31 times coverage.

The investment grade credit ratings that the Partnership earned in June allowed us to raise $350 million of long-term debt in the public market for the first time. The credit ratings and 4.65 per cent coupon on the offering are a testament to our low-risk business model, disciplined investment approach and quality assets. In July, the Partnership also further enhanced its financial flexibility when it renewed and increased its line of credit, doubling its borrowing capacity to $500 million.

The Partnership's financing activities in 2011 strengthened our financial situation and positions us well for future growth opportunities, whether through third-party acquisitions or asset purchases from TransCanada.

PARTNERSHIP OUTLOOK

The emergence of shale gas in both Canada and the U.S. has resulted in natural gas prices becoming very competitive in energy markets relative to competing fuels. In the short term this supply growth, in addition to a warmer than normal winter, has resulted in high natural gas storage levels and lower natural gas prices. While these conditions may impact volume throughput on our assets, the Partnership's overall position remains strong as many of our assets have long term contracts providing stable cash flows. Our solid cash distribution coverage also allows us to weather these short term market conditions.

Longer term, the outlook in North America for natural gas as a key energy source is very strong. Today our pipelines move approximately eight per cent of North America's daily gas needs. As the market begins to respond to the increase in supply of this affordable, abundant, and clean fuel resource, our Partnership's pipelines will continue to provide safe and reliable transportation of natural gas.

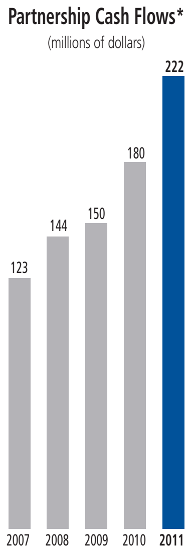
I am confident that the Partnership's accomplishments in 2011 will deliver long-term value to unitholders and that these activities have created solid foundations upon which we are well positioned for future growth.

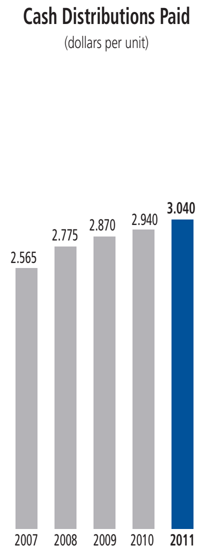
On behalf of TC PipeLines, LP

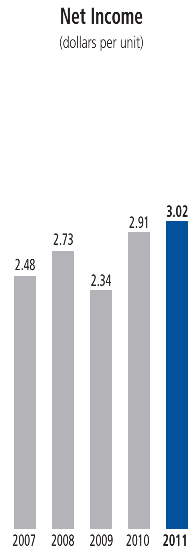
Steve Becker
President, TC PipeLines, GP, Inc.

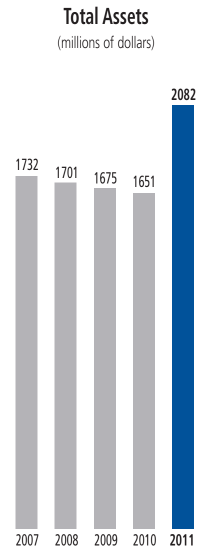
FINANCIAL HIGHLIGHTS

YEAR ENDED DECEMBER 31	2007	2008	2009	2010	2011
(millions of dollars, except per unit amounts)					
CASH FLOW					
Partnership cash flows*	123.2	143.5	150.2	180.1	**222.4**
Cash distributions paid	86.7	108.6	117.0	138.7	**154.8**
INCOME STATEMENT					
Net income**	94.7	123.0	106.1	137.1	**157.4**
Net income prior to recast*	89.0	107.7	97.8	137.1	**157.4**
BALANCE SHEET					
Total assets**	1,732.4	1,701.1	1,675.1	1,650.5	**2,082.0**
Long-term debt (including current maturities)	573.4	536.8	541.3	513.9	**742.5**
Partners' equity	900.1	875.6	1,103.5	1,112.5	**1,333.0**
COMMON UNITS STATISTICS (PER UNIT)					
Cash distributions paid	$ 2.565	$ 2.775	$ 2.870	$2.940	**$3.040**
Net income	$ 2.48	$ 2.73	$ 2.34	$2.91	**$3.02**
COMMON UNITS OUTSTANDING (MILLIONS)					
Weighted average for the year	32.3	34.9	38.7	46.2	**51.1**
End of year	34.9	34.9	46.2	46.2	**53.5**









*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, 2011, filed with the Securities Exchange Commission (SEC).

**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, 2011, filed with the SEC.

This material 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, including market conditions and other factors beyond the Partnership's control. Important factors that could cause actual results to differ materially from those described in the forward-looking statements herein are found in TC PipeLines, LP's Forms 10-K and 10-Q as filed with the SEC.

TC PIPELINES, LP

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

PART I

FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This report includes certain 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. Forward-looking statements are identified by words and phrases such as: "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "forecast," "should," "predict," "could," "will," "may," and other terms and expressions of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking. These statements are based on management's beliefs and assumptions and on currently available information and include, but are not limited to, statements regarding anticipated financial performance, future capital expenditures, liquidity, plans and objectives for future operations, organic and strategic growth opportunities, contract renewals and ability to market open capacity, business prospects, outcome of regulatory proceedings, and cash distributions to unitholders.

Forward-looking statements involve risks and uncertainties that may cause actual results to differ materially from the results predicted. Factors that could cause, and in certain instances have caused, actual results to differ materially from those contemplated in forward-looking statements include, but are not limited to:

- the ability of our pipeline systems to make cash distributions and generate positive operating cash flows;
- the ability to sell unsold capacity and renew expiring contracts on our pipeline systems;
- the competitive conditions in our industry and the ability of our pipeline systems to market capacity on favorable terms, which is affected by, among other factors:
  - demand for and prices of natural gas;
  - level of natural gas basis differentials;
  - weather conditions that impact natural gas supply and demand;
  - competitive conditions in the overall natural gas and electricity markets;
  - availability of supplies of Canadian and United States of America (U.S.) natural gas, including the growing supplies of natural gas from shale gas basins such as Horn River and Montney in Western Canada and Appalachian and Barnett in the U.S., and natural gas from conventional basins such as the Western Canada Sedimentary Basin (WCSB), Rocky Mountain, Mid-Continent and Gulf Coast basins;
  - competitive natural gas transmission developments;
  - uncertainty relating to TransCanada's Mainline (Mainline) rates;
  - the availability of natural gas storage capacity and storage levels;
  - the level of production of natural gas liquids and the subsequent impact on relative competitiveness of gas producing basins; and
  - the ability of shippers to pay including meeting creditworthiness requirements;
- the costs and impact of changes in laws and governmental regulations affecting our pipeline systems, particularly regulations issued by the Federal Energy Regulatory Commission (FERC), the U.S. Environmental Protection Agency (EPA), U.S. Department of Transportation (DOT) and U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA);
- the outcome and frequency of rate proceedings on our pipeline systems;
- changes in relative cost structures and production levels of natural gas producing basins;
- regulatory, financing, construction and operational risks associated with construction and operation of interstate natural gas pipelines;
- our ability to identify and complete expansion projects and other accretive growth opportunities;

- the performance by the shippers of their contractual obligations on our pipeline systems;
- changes in the taxation of limited partnerships by states or the federal government such as the elimination of pass-through taxation and the imposition of entity level taxes;
- operating hazards, casualty losses and other matters beyond our control; and
- unfavorable economic conditions and the impact on capital markets.

Please read Item 1A. "Risk Factors" for additional information on the risks and uncertainties listed above and other factors that could have material adverse effects on our future results of operations and financial condition. All 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 any forward-looking statements or information to reflect new information, subsequent events or otherwise.

Item 1. Business

GENERAL

Limited Partnership

We are a publicly traded Delaware limited partnership formed in 1998 by TransCanada Corporation and its subsidiaries (TransCanada) to acquire, own and participate in the management of energy infrastructure businesses in North America. Through our pipeline systems we transport natural gas in the United States. Our common units are traded on the New York Stock Exchange (NYSE) under the symbol "TCP."

We are managed by our general partner TC PipeLines GP, Inc. (General Partner), which is an indirect, wholly-owned subsidiary of TransCanada. Through its subsidiaries, TransCanada owns an approximately 33.3 percent equity interest in us, including a 31.3 percent limited partner interest and an effective two percent general partner interest held by our General Partner. 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.

Recent Business Developments

Cash Distributions – In 2011, 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 July 2011, we increased our quarterly cash distribution by three percent to $0.77 per common unit and during fiscal year 2011, we paid cash distributions of $3.04 per common unit. On February 14, 2012, we paid a cash distribution of $0.77 per common unit for fourth quarter 2011.

GTN and Bison Acquisitions – On May 3, 2011, we acquired 25 percent membership interests in each of GTN and Bison from subsidiaries of TransCanada (Acquisitions) at a purchase price of $605.0 million. GTN owns a pipeline system that extends from an interconnection at the Canadian border near Kingsgate, British Columbia to a point near Malin, Oregon at the California border. The Bison pipeline system extends from the Powder River Basin near Gillette, Wyoming to Northern Border's pipeline system in Morton County, North Dakota.

Common Unit Offering – On May 3, 2011, we completed a public offering of 7,245,000 common units at $47.58 per common unit for gross proceeds of $344.7 million and net proceeds of $330.9 after unit issuance costs. Our General Partner maintained its effective two percent general partner interest in us by contributing $6.7 million in connection with the offering. The offering was used to finance the Acquisitions.

Debt Offering – On June 17, 2011, we closed a $350.0 million public debt offering of 10-year, senior unsecured notes bearing an interest rate of 4.65 percent maturing June 15, 2021. The net proceeds of $347.1 million were used to repay funds borrowed under our bridge loan facility used to finance the Acquisitions and to partially repay borrowings under our then existing senior revolving and term loan credit facility.

Refinancing – On July 13, 2011, we amended our senior credit facility increasing the revolving credit facility to $500 million with a $250 million accordion feature subject to lenders approval, with a London Interbank Offered Rate (LIBOR)-based interest rate plus a margin and extending the maturity date of the senior revolving credit facility to July 13, 2016. Our $300 million senior term loan matured on December 12, 2011, and was repaid through a draw on the senior revolving credit facility.

GTN Rate Settlement – On August 12, 2011, GTN filed a petition with the FERC requesting approval of a Stipulation and Agreement of Settlement (GTN Settlement) with shippers and regulators regarding GTN's rates and terms and conditions of service. In November 2011, the FERC approved the GTN Settlement without modification, effective January 1, 2012. The GTN Settlement includes a moratorium on the filing of future rate proceedings until December 31, 2015. Following the expiration of the moratorium, GTN must file a rate case for new rates to be effective January 1, 2016.

Northern Border Princeton Lateral – In November 2011, Northern Border began service on its Princeton Lateral, a nine mile lateral connecting the Northern Border pipeline system to a delivery point in Bureau County, Illinois. The lateral is fully subscribed for a ten-year term. The cost of the lateral is approximately $19 million, of which we contributed approximately $5 million.

Tuscarora Rate Proceeding – On May 24, 2011, the FERC issued an order initiating an investigation pursuant to Section 5 of the Natural Gas Act of 1938 (NGA) to determine whether Tuscarora's existing rates for jurisdictional services were unjust and unreasonable following a complaint filed by the Public Utilities Commission of Nevada (PUCN) and Sierra Pacific Power Company d/b/a NV Energy (NV Energy). On December 23, 2011, Tuscarora filed a petition with the FERC requesting approval of a Stipulation and Agreement of Settlement (Tuscarora Settlement), resolving all issues raised in the Section 5 proceeding to be effective January 1, 2012. On February 6, 2012, the Administrative Law Judge assigned to the case certified the settlement proposal and made a recommendation that the FERC approve the settlement. A decision from the FERC is pending.

NARRATIVE DESCRIPTION OF BUSINESS

Business Strategies

- Our strategic approach is to invest in long-lived critical energy infrastructure that provides reliable delivery of energy to customers.
- 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 goal is to maximize revenue opportunities through utilization of our pipeline systems, while maintaining a commitment to safe and reliable operations.

Our Pipeline Systems

We have equity ownership interests in four natural gas interstate pipeline systems that are accounted for on an equity basis and two wholly-owned pipelines that are accounted for on a consolidated basis. Collectively, they are designed to transport approximately 8.9 billion cubic feet per day (Bcf/d) of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western and Midwestern U.S. and Central Canada. All of our pipeline systems are operated by subsidiaries of TransCanada.

Our pipeline systems include:

- 46.45 percent of Great Lakes. 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.

- 50 percent of Northern Border. The remaining 50 percent is held indirectly by ONEOK Partners, L.P.

  The Northern Border pipeline system consists of 1,407 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 an average design capacity of approximately 2.4 Bcf/d at Port of Morgan, Montana. Construction of Northern Border's system was initially completed in 1982, followed by numerous expansions and extensions.

- 25 percent of GTN. The remaining 75 percent is owned by a subsidiary of TransCanada.

  The GTN pipeline system consists of 1,353 miles of pipeline extending from an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border. The GTN pipeline has an average design capacity of approximately 2.9 Bcf/d at Kingsgate. The original construction of the GTN pipeline system was completed in 1961, followed by numerous expansions.

- 25 percent of Bison. The remaining 75 percent is owned by a subsidiary of TransCanada.

  The Bison pipeline system consists of 303 miles of pipeline extending from the Powder River Basin near Gillette, Wyoming to Northern Border's pipeline system in Morton County, North Dakota. The Bison pipeline system was placed into service in January 2011 and has an average design capacity without compression of 407 million cubic feet per day (MMcf/d).

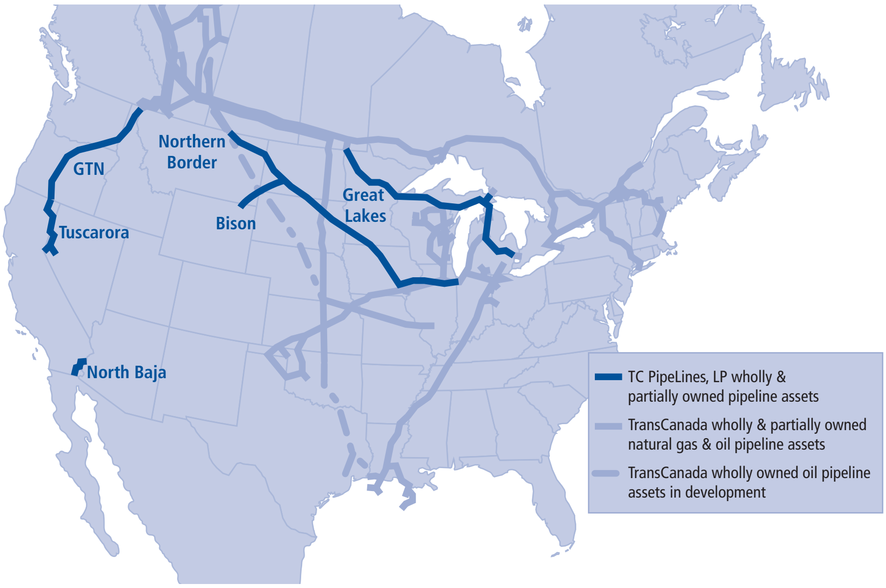
- 100 percent of North Baja.

  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 Rosarito natural gas pipeline near Ogilby, California on the Mexican border. North Baja has an average design capacity of 500 MMcf/d for southbound transportation and 600 MMcf/d for northbound transportation. The North Baja pipeline system was initially placed into service in 2002, followed by expansions and extensions in 2008 and 2010.

- 100 percent of Tuscarora.

  The Tuscarora pipeline system consists of 305 miles of pipeline extending from the GTN pipeline system near Malin, Oregon to a terminus near Wadsworth, Nevada. Tuscarora has an average design capacity of 230 MMcf/d. The Tuscarora pipeline system was initially placed into service in 1995, followed by numerous expansions and extensions.

The map below shows the location of our pipeline systems.



Relationship with TransCanada

We have a strong relationship with our sponsor TransCanada. TransCanada is a major energy infrastructure company, listed on the Toronto Stock Exchange and NYSE, with more than 60 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. TransCanada owns approximately $49.0 billion in total assets, including 35,500 miles of wholly-owned natural gas pipelines, interests in an additional 7,000 miles of natural gas pipelines, 2,154 miles of wholly-owned oil pipelines and approximately 380 billion cubic feet of storage capacity. TransCanada also owns, controls or is developing over 10,800 megawatts of power generation.

Subsidiaries of TransCanada operate our pipeline systems and purchase pipeline capacity. We have purchased assets from TransCanada and jointly participated with TransCanada in acquiring assets from third parties, including acquisitions that we would be unable to pursue on our own. We may have similar opportunities going forward. 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 13. "Certain Relationships and Related Transactions, and Director Independence" for more information on our relationship with TransCanada.

Supply

Natural gas is transported from producing regions and liquefied natural gas (LNG) import facilities to market hubs or interconnects for distribution to natural gas consumers. Significant producing regions in North America include the Gulf of Mexico, WCSB, Mid-Continent, Rockies, Appalachian Basin, Permian Basin and San Juan Basin. Recent increases in the development of shale and other unconventional gas have resulted in increases in overall North American natural gas production and increased reserves. The Northeastern U.S., the Midwest and Western U.S. are three large natural gas consuming regions. Over the past few years, significant new pipeline infrastructure has been added to move natural gas from producing regions to market areas. These factors impact the transportation value on pipelines, including our pipeline systems. Additionally, development of new producing regions, such as the Marcellus shale in the Northeastern U.S., and the Montney and Horn River shale areas in northeastern British Columbia, Canada and development of proposed new pipelines will also impact North American natural gas flows. In the longer term, reserves from Arctic natural gas also have the potential to increase supply exiting the WCSB, although this gas could potentially be exported as LNG, possibly limiting the supply.

Great Lakes transports natural gas produced in the WCSB that it receives at an interconnection with the Mainline pipeline at the Canadian border near Emerson, Manitoba, Canada and 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 transports natural gas produced in the WCSB that it receives at an interconnection with TransCanada's Foothills pipeline at the Canadian border near Port of Morgan, Montana and transports natural gas produced in the Williston Basin of Montana and North Dakota, and the Powder River Basin of Wyoming and Montana.

GTN primarily transports natural gas produced in the WCSB that it receives at an interconnection with the Foothills Pipeline at the Canadian border near Kingsgate, British Columbia. GTN also has access to Rocky Mountain sourced natural gas through interconnects with the Ruby Pipeline and Northwest Pipeline.

Bison transports natural gas produced in the Powder River Basin to an interconnect with Northern Border.

North Baja transports southbound natural gas produced in the West Texas and Southern Rocky Mountain regions that it receives from an interconnection with EPNG at Ehrenberg, Arizona. North Baja also has the ability to transport northbound natural gas sourced from the Energia Costa Azul LNG terminal in Mexico.

Tuscarora transports natural gas produced in the WCSB that it receives from its interconnection with GTN and in the Rocky Mountain region through an interconnection with the Ruby Pipeline.

Demand

The demand for transportation service on our pipeline systems can be affected by several factors, including:

- demand for natural gas in 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;
- alternative electric power generation sources including hydro-electric, solar, wind power, coal and nuclear;
- weather conditions; and
- availability and competitiveness of alternative supply sources and storage alternatives in the consuming market.

The impact on revenue from 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. Revenues on GTN, Bison, Tuscarora and North Baja are primarily underpinned by long-term firm contracts and experience limited volatility in revenue due to seasonal changes in demand or market conditions. Great Lakes, however, is more dependent on shorter term contracts and therefore can experience demand changes and revenue volatility related to seasonal factors or market conditions.

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

While Northern Border's revenues are substantially underpinned by contracts over the next 12 to 18 months, they can be affected by seasonal demand for transportation services that have 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, when not contracted. Northern Border's tariff has a seasonal rate structure providing for higher rates during traditional peak months.

GTN is not fully contracted; however, effective January 1, 2012 its rates are based on its current contracted capacity. As a result, GTN's revenues will be subject to variation only as a result of capacity sold at levels above its current contracted amount.

Bison, Tuscarora and North Baja have long-term firm contracts and do not experience significant revenue volatility.

Competition

Competition among natural gas pipelines is based primarily on transportation rates and proximity to natural gas supply areas and consuming markets. Four of our pipelines systems, Great Lakes, Northern Border, GTN, and Tuscarora, compete for gas exiting the WCSB with each other as well as with other pipelines, including TransCanada's Mainline system, the Alliance pipeline and the Westcoast pipeline. "Gas exiting the WCSB" is the term we use to represent the net supply of natural gas for export from the WCSB region.

Great Lakes, Northern Border and Tuscarora compete in their respective market areas with gas supplies from other basins, including the Rocky Mountain, Mid-Continent, Gulf Coast, Appalachian and Marcellus Basins. Primary competing pipelines in Great Lakes' and Northern Border's market areas include pipelines operated by Northern Natural Gas Company, Natural Gas Pipeline Company of America, Panhandle Eastern Pipeline Company, ANR, Viking Gas Transmission Company and Rockies Express Pipeline L.L.C. GTN primarily competes into California with Ruby Pipeline L.L.C., Kern River Gas Transmission, El Paso Natural Gas and Transwestern Pipeline. GTN also competes into Pacific Northwest markets with Northwest Pipeline.

Bison competes for deliveries with other pipelines that transport natural gas supplies within and away from the Rocky Mountain basin.

North Baja's pipeline southbound capacity competes with deliveries of LNG received at the Costa Azul terminal in Mexico. When LNG shipments are received at Costa Azul, North Baja's northbound capacity competes with pipelines that deliver Rocky Mountain, Permian and San Juan basin gas into the southern California area, including Transwestern Pipeline and El Paso Natural Gas.

Tuscarora competes for deliveries primarily into the northern Nevada natural gas market 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 producing 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. The majority of our pipeline systems' natural gas transportation services are provided through firm service transportation contracts with a reservation or demand charge which reserves pipeline capacity, regardless of use, for the term of the contract. The revenues associated with capacity reserved 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 after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges (or utilization fees) primarily based on distance and the volume of natural gas they transport.

Transportation contracts expire 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 term 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 or contracted at lower rates. Unsold capacity may be recontracted if and when market conditions become more favorable. 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, if shippers renew, typically they do so on an annual basis. Interruptible transportation service may also be available on a day to day basis, subject to the level of firm capacity utilized and other operational considerations.

As of January 1, 2012, the following table provides information with respect to the contract profile of our pipeline systems over the next five years, calculated as a percentage of the Partnership's proportionate share of 2011 revenue from each of our pipeline systems, being $387 million:

	Future Revenues Underpinned by Long-Term Contracts, as a Percentage of 2011 Total Revenue[(a)(b)]
2012	75%
2013	57%
2014	50%
2015	45%
2016	41%

(a) Long-term contracts are contracts with terms greater than twelve months.

(b) Projections are based on rates in effect as of January 1, 2012.

More than half of Great Lakes' capacity is under contracts that expire in 2012 and 2013. Great Lakes' long-haul capacity contracts have typically been subject to annual renewals. Re-contracting occurs throughout the year; however, shippers typically have contracted on Great Lakes for the upcoming natural gas year starting on November 1 of each year. Although Great Lakes has historically been fully contracted, Great Lakes currently has approximately 75 percent of its long-haul capacity contracted through to October 31, 2012. Great Lakes' ability to sell its current and future available capacity will depend on future market conditions which are impacted by a number of factors including, weather for the remainder of the winter and into the summer months, levels of natural gas in storage, the price of natural gas liquids and the associated impact to North American natural gas production, and the level of the Mainline's tolls.

In conjunction with their contracts on the Bison pipeline, Bison shippers also contracted for capacity on the Northern Border system for ten years. Including these contracts, Northern Border's long-haul capacity is substantially contracted through March 2013. All of the existing Bison annual capacity is fully contracted through 2020.

GTN currently has contracts for approximately 1,500 MMcf/d with the majority of contract expirations occurring between 2015 and 2023. On October 31, 2011, a customer did not renew a contract for 250 thousand dekatherms per day (MDth/d), or approximately 245 MMcf/d. In the GTN Settlement, rates were determined reflecting GTN's rate base, revenue requirement and contract levels.

North Baja has long-term contracts for a substantial portion of its capacity with terms that expire between 2022 and 2031. Tuscarora has long-term contracts for substantially all of its capacity with terms expiring after 2016. In addition, if the Tuscarora Settlement is approved, there will be a three-year extension to the term of several contracts with Tuscarora's largest customer.

Average Daily Scheduled Volumes

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

	Average Daily Scheduled Volumes[a]		
December 31 *(million cubic feet per day)*	**2011**	2010	2009
Great Lakes	**2,274**	2,203	1,992
Northern Border	**2,660**	2,471	1,934
GTN[b]	**1,861**	2,198	2,176

[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 Bison, 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.

[b] The interest in GTN was acquired on May 3, 2011. Average daily scheduled volumes for periods prior to May 3, 2011 are presented for comparative information purposes only.

Throughput on our pipeline systems will vary from year to year due to changes in the market conditions for natural gas across the respective systems. Weather conditions may impact this demand as well as our pipeline systems' physical capacity to transport gas.

For the year ended December 31, 2011, no single customer accounted for more than ten percent of our proportionate share of our pipelines systems' operating revenues.

Government Regulation

Federal Energy Regulatory Commission

Regulatory Authority
All of our pipeline systems are regulated by the FERC under the Natural Gas Act of 1938 (NGA) and Energy Policy Act of 2005, which give the FERC jurisdiction to regulate virtually all aspects of our business, including:

- transportation of natural gas in interstate commerce;
- 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.

Our pipeline systems' operating revenues are determined based on rates stated in our tariffs which are approved by the FERC. Tariffs specify the general terms and conditions for pipeline transportation service including the rates that may be charged. The FERC, either through hearing a rate case or as a result of approving a negotiated settlement, approves the maximum rates permissible for transportation service on a pipeline system which are designed to recover the pipeline's 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 a number of factors including costs incurred, contracted capacity and transportation path, the volume of natural gas transported, capacity sold and rates charged.

FERC Rate Proceedings
Great Lakes – Great Lakes operates under a rate settlement approved by the FERC in July 2010. The settlement included a moratorium on participants and customers filing any NGA Section 5 rate case to place new rates into effect prior to November 1, 2012. In addition, Great Lakes is required to file a NGA Section 4 general rate case no later than November 1, 2013.

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. Northern Border is required to file a rate case on or before December 31, 2012.

GTN – On August 12, 2011, GTN filed a petition with the FERC requesting approval of the GTN Settlement with shippers and regulators regarding GTN's rates and terms and conditions of service. In November 2011, the FERC approved the GTN Settlement, without modification, effective January 1, 2012. The GTN Settlement includes a moratorium on the filing of future rate proceedings until December 31, 2015. Following the expiration of the moratorium, GTN must file a rate case such that the new rates will be effective January 1, 2016. GTN's new rates were determined in a settlement reflecting GTN's rate base, revenue requirement, and contract levels.

Tuscarora – On May 24, 2011, the FERC issued an order initiating an investigation pursuant to Section 5 of the NGA to determine whether Tuscarora's existing rates for jurisdictional services were unjust and unreasonable. The FERC initiated this proceeding following a complaint filed by the PUCN and NV Energy. On December 23, 2011, Tuscarora filed a petition with the FERC requesting approval of the Tuscarora Settlement, resolving all issues raised in the Section 5 proceeding. On February 6, 2012, the Administrative Law Judge assigned to the case certified the settlement proposal and made a recommendation that the FERC approve the settlement. The settlement includes three-year contract extensions to the term of a number of contracts with Tuscarora's largest customer. If approved, the rates will be effective January 1, 2012, and a moratorium on the filing of future rate proceedings under NGA Sections 4 or 5 will extend until December 31, 2014. Pursuant to the settlement, Tuscarora will have no future obligation to file a Section 4 rate case. A decision from the FERC is pending.

Environmental Matters

Our pipelines 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. 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.

We do not anticipate that costs of compliance with existing environmental laws and regulations will 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. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our financial position, results of operations and/or cash flows.

To date, we have not accrued any environmental liabilities, and therefore have not established an environmental reserve with respect to any environmental matters. Nonetheless, these laws and regulations can impact business operations in many ways, such as requiring the monitoring and installation of pollution abatement or control equipment and imposing requirements relating to the proper handling of wastes, and requiring remedial action to mitigate pollution conditions.

Below is a discussion of some of the applicable environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all environmental laws and regulations.

- *Waste and Hazardous Substance Statutes* – The operations of our pipeline systems generate hazardous waste that are subject to the Resource Conservation and Recovery Act and comparable state statutes. Additionally, federal and state regulators have adopted strict disposal standards for non-hazardous industrial waste and hazardous substances, such as the Solid Waste Disposal Act and the Comprehensive Response, Compensation and Liability Act. These requirements are subject to rigorous waste management and disposal practices to ensure compliance.
- *The 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, reporting, and in some cases, control 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 comply with air permits containing various emission and operational limitations, or requiring the use of emission control or abatement technologies.
- *Toxic Substances Control Act (TSCA)* – The TSCA addresses the production, importation, use, and disposal of specific chemicals and provides the EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and mixtures. These include polychlorinated biphenyls (PCBs), asbestos, radon and lead-based paint.
- *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 or adjacent to waters of the U.S. The discharge of pollutants into regulated waters is generally prohibited, except in accordance with the terms of a permit issued by the EPA or a delegated state or federal agency. The CWA and regulations implemented also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit.
- *National Environmental Policy Act (NEPA)* – Natural gas transportation activities can be subject to review under NEPA, or analogous federal or state requirements. NEPA requires federal agencies, including the Department of the Interior or the FERC, to evaluate 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.
- *The Endangered Species Act (ESA)* – The ESA restricts activities that may affect endangered or threatened species or their habitats. The designation of previously unidentified or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Climate Change

- Substantial uncertainty exists regarding the impact of new and proposed greenhouse gas (GHG) laws and regulations. We cannot estimate the effect of proposed legislation on our future financial position, results of operations or cash flow. However, 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 other compliance instruments. Although many of these costs might be recoverable in the rates charged to our pipeline customers, recovery through these mechanisms is uncertain. Measures to address climate change through the regulation of GHG emissions are in various phases of development at international, federal, regional and state levels, a number of which are outlined below:

- *International Climate Change Measures* – The current international framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets for developed countries for the 2008-2012 period. The U.S. has not ratified the Kyoto Protocol. Subsequent United Nations-sponsored negotiations in December 2010 have resulted in limited political agreement and a binding successor accord to the Kyoto Protocol has not been realized.
- *Climate Change Legislation* – Federal, regional and state legislation to address climate change through the regulation of GHG emissions is in various stages of development. On the federal level, specific policy objectives and timing remain uncertain. However, on the state level, a number of states have joined regional GHG initiatives or have independently initiated programs that would mandate reductions in GHG emissions, primarily through regional GHG 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. For example, in California, the Air Resources Board has implemented a cap-and-trade regulation that will (a) require large industrial users of fossil fuels to obtain allowances authorizing GHG emissions after January 1, 2012, and (b) impose allowance requirements upon natural gas importers commencing January 1, 2015. The costs of allowances could result in material reductions in demand for natural gas or in increased compliance costs for our pipeline systems. Because of the uncertainty of policy and regulatory compliance schemes, the future effects on our pipelines cannot be predicted.

  We believe that market-based legislation that sets a price on carbon emissions could increase demand for natural gas, because less GHG emissions are generated from the combustion of natural gas as compared to the combustion of coal and oil. The 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* – In early 2011, the EPA finalized a Prevention of Significant Deterioration and Title V Greenhouse Gas "Tailoring Rule" to address how GHG emissions would be regulated under the CAA. Stationary sources of GHG 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. At this time, it is not anticipated that the costs will be material; however, many implementation details are unknown and are currently being addressed in industry discussions with the EPA. As clarity emerges regarding implementation of the Tailoring Rule, additional permitting requirements could result in additional costs and delays in completing projects.
- *Energy Legislation* – On-going legislative and regulatory efforts to encourage the use of cleaner energy technologies at the federal, state and local levels are also in various stages of development, some in conjunction with current GHG emission efforts. Natural gas is a fossil fuel that is generally associated with lower GHG 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, and accordingly, our pipeline systems. The timing and specific policy objectives of an energy policy and incentives remain highly uncertain; 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.

Safety Matters

Our pipeline systems are affected by existing and proposed pipeline safety regulations imposed by PHMSA with respect to pipeline design, installation, testing, construction, operation, replacement and management. As experienced by our Bison pipeline system in 2011, these regulations can impact our pipeline systems ability to operate. Following a line break on July 20, 2011, the Bison pipeline system was shut down for 33 days before PHMSA permitted the pipeline to return to service at reduced pressure, which allowed Bison to deliver approximately 60 percent of its contracted quantities. Bison received authorization from PHMSA to return to full service on October 8, 2011.

The Pipeline Safety Improvement Act of 2002 (Pipeline Safety Act) requires pipeline companies to perform baseline integrity assessments on pipeline segments that traverse densely populated areas or near sites that are specifically 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 94 percent of the baseline assessments have been completed for our pipeline systems. The final baseline assessments are scheduled to be completed in 2012. Although only a small portion of our pipelines are in HCAs, approximately 60 percent of our pipeline systems have been in-line inspected as part of performing the baseline assessments. An additional 30 percent of our pipeline systems are inspected as part of the overall pipe integrity program. The remaining 10 percent of our pipeline systems currently do not require inspections. The requirement for inspections is reviewed and adjusted annually.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Act) was enacted. The 2011 Pipeline Act reauthorized and amended the previous PIPES Act of 2006 and Pipeline Safety Act. The 2011 Pipeline Act reauthorizes the PHMSA federal pipeline safety programs through fiscal year 2015 and includes a number of additional provisions affecting pipeline owners and operators. Items that may have a material effect on pipeline owners and operators include increases to the cap on civil penalties for violators of pipeline regulations and additional civil penalties for obstructing investigations; a directive for PHMSA to develop regulations requiring the installation of automatic or remote control shut off valves for new or replaced transmission pipelines; a directive for PHMSA to establish requirements for gas transmission pipeline operators to confirm the physical and operation characteristics and their maximum allowable operating pressure (MAOP) for pipelines in more populated areas (class 3 and 4 locations) and HCAs; a directive that PHMSA issue regulations requiring gas transmission pipeline operators to report to PHMSA any pipeline segments with insufficient MAOP records; and a requirement that PHMSA issue regulations on testing of grandfathered or previously untested gas transmission pipelines.

PHMSA and the Comptroller General are also required by the 2011 Pipeline Act to conduct several studies and develop several reports over the next two years, some of which are a necessary prelude to additional rulemaking. These studies include a study on expanding Integrity Management Program (IMP) requirements outside of HCAs, and possibly eliminating Class Location requirements, as well as a report to Congress on using Risk Based Assessment Intervals for IMP.

In addition, there are various other ongoing legislative and regulatory measures proposed at the federal and state levels to increase pipeline safety. These legislative and regulatory policies, if enacted, may impact our pipeline systems, 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.

EMPLOYEES

We do not have any employees. We are managed and operated by our General Partner. Subsidiaries of TransCanada operate our pipelines systems pursuant to operating agreements.

AVAILABLE INFORMATION

We make available free of charge on or through our website (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). Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and the Audit Committee Charter of our General Partner are also available on our website under "Corporate Governance." We will also provide copies of these documents at no charge upon request. The 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. Realization of any of the risks described below could 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. Investors should review and carefully consider all of the information contained in this report, including the following discussion of risks when making investment decisions relating to our partnership.

RISKS RELATED TO OUR BUSINESS

The long-term financial condition of our pipeline systems, except Bison, North Baja and Tuscarora, is dependent on the continued availability of and demand for natural gas exiting the WCSB.

The long-term financial condition of our pipeline systems, except Bison, North Baja and Tuscarora is dependent on the continued availability of and demand for natural gas exiting the WCSB. For this reason, the continuous supply of gas exiting the WCSB is crucial to the long-term financial performance of these pipeline systems. Gas exiting the WCSB depends on numerous factors, including the demand for natural gas within Western Canada, WCSB natural gas production and natural gas prices. Western Canadian demand for natural gas is growing and is expected to continue to increase primarily as a result of increased demand for natural gas used to extract oil from the oil sands and to generate electricity. Higher Western Canadian demand may reduce the amount of natural gas available for flow on our pipeline systems.

As conventional natural gas production in the WCSB declines, the continued availability of gas exiting the WCSB will require the development of unconventional natural gas resources such as the Montney and Horn River formations in Western Canada. Additional sources of potential future supply also include proposed natural gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada. The development of these resources or the completion of these projects may be affected by low natural gas prices or high exploration costs. The cancellation, changes in route or delays in the construction of such projects or the development of unconventional natural gas supplies could adversely affect gas exiting the WCSB and flowing on our pipeline systems in the long-term.

There are a number of pipelines and related LNG export terminals proposals currently under evaluation that could, if constructed, export gas from the WCSB (primarily the Montney and Horn River formations) from Canada's west coast beginning in the latter half of the decade. Unless there is a corresponding increase in the amount of natural gas production in the WCSB, there could be diminished gas volumes available to exit the WCSB on existing pipelines, including those owned by us.

Our financial performance depends to a large extent on the capacity contracted and rates charged on our pipeline systems. If the available supply of natural gas in the WCSB declines, existing shippers on Great Lakes, Northern Border, and GTN may decide not to renew their expiring contracts and we may not be able to find replacement shippers for the lost capacity. The loss of contracted capacity or sale of capacity at unfavorable rates could adversely affect our financial position, results of operations and ability to make cash distributions.

Our pipeline systems may not be able to renew or replace expiring transportation contracts or do so at acceptable rates or for a long term.
Our primary exposure to market risk and competitive pressure occurs at the time existing shipper contracts expire and are subject to renegotiation and renewal. Customers may not renew their transportation contracts 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. Our ability to extend and replace expiring contracts, particularly long-term firm contracts, on terms comparable to prior contracts or on any terms depends on this and other factors beyond our control, including:

- the availability and supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply;
- competition from other existing or proposed pipelines;
- contract expirations and capacity on competing pipelines;
- changes in rates upstream or downstream of our pipeline systems, which can affect our pipeline systems' relative competitiveness in attracting volumes;
- basis differentials between the market location and location of natural gas supplies;
- the liquidity and willingness of shippers to contract for transportation services; and
- regulatory developments.

Great Lakes, Northern Border and GTN are experiencing these competitive pressures and may continue to be affected by these factors as their long-term contracts expire. Ongoing competitive pressures could adversely affect the ability of Great Lakes, Northern Border and GTN to extend or replace expiring contracts on comparable terms, which could have a material adverse effect on our business, financial condition, results of operations and our ability to make cash distributions.

Rates and other terms of service of our pipeline systems are subject to approval and potential adjustment by the FERC, which could limit their ability to recover all costs of operations.
Our pipeline systems are subject to extensive regulation over nearly every aspect of their business, including the rates that they can charge to shippers as well as their return on equity. Under the NGA, our rates must be just, reasonable and not unduly discriminatory. Actions by FERC could adversely affect the ability of our pipeline systems to recover all of their current or future costs and earn a reasonable rate of return.

If our pipeline systems do not make additional capital expenditures sufficient to offset depreciation expense, our rate base will decline and our earnings and cash flow will decrease over time.
Our pipeline systems are allowed to collect from their customers a return on their assets or "rate base" as reflected in their financial records, as well as recover a portion of that rate base over time through depreciation. In the absence of additions to the rate base through capital expenditures, the rate base will decline over time and revenue and cash flows associated with return on the rate base will likely decline.

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 amount of our pipeline systems' operating costs; and
- the ability of shippers to pay including meeting creditworthiness requirements.

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

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 pipeline systems to complete expansion projects and make and integrate acquisitions that result in an increase in cash per common unit generated from operations. We may be unable to complete successful, accretive expansion projects or acquisitions for any of the following reasons:

- an inability to identify attractive expansion projects or assets;
- an inability to obtain necessary rights-of-way or governmental approvals.
- an inability to successfully integrate the businesses we build or acquire;
- an inability to raise financing for such expansion projects or acquisitions on economically acceptable terms;
- an inability to access capital markets;
- incorrect assumptions about volumes, reserves, revenues and costs, including synergies and potential growth; or
- an inability to secure adequate customer commitments to use the newly expanded or acquired facilities.

Expansion projects or future acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Even if we complete expansion projects or make acquisitions that we believe will be accretive, these expansion projects or acquisitions may nevertheless reduce our cash from operations on a per-unit basis. Any expansion project or acquisition involves potential risks, including, among other things:

- an inability to complete expansion projects on schedule or within the budgeted cost due to the unavailability of required construction personnel, equipment or materials, and the risk of cost overruns resulting from inflation or increased costs of materials, labor and equipment;
- a decrease in our liquidity as a result of using a significant portion of our available cash or borrowing capacity to finance the project or acquisition;
- an inability to receive cash flows from a newly built or acquired asset until it is operational; and
- unforeseen difficulties operating in new business areas or new geographic areas.

As a result, our new facilities may not achieve expected investment returns, which could adversely affect our results of operations, financial position or cash flows. If any expansion projects or acquisitions that we ultimately complete are not accretive to cash available for distribution, our ability to make distributions may be reduced.

We are exposed to credit risk when a shipper fails to perform its contractual obligations.

Our pipeline systems are subject to a risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided and future performance, over the remaining contract terms under firm transportation contracts. Our tariffs only allow us to require limited credit support in the event that our customers are unable to pay for our services. If a significant customer has credit or financial problems which result in a delay or failure to pay for services provided by us or contracted for with us, it could have a material adverse effect on our business and results of operations. In addition, as contracts expire, the failure of any of our customers could also result in the non-renewal of contracted capacity, which could have a material adverse effect on our business and results of operations.

Our pipeline systems are subject to operational hazards and unforeseeable interruptions that may not be covered by insurance.

Our pipeline systems are subject to inherent risks including earthquakes, adverse weather conditions and other natural disasters; terrorist activity or acts of aggression; damage to a pipeline by a third party excavation or construction; explosions, pipeline failures, mechanical and process safety failures; release of pollution or contaminants into the environment; and other environmental hazards. Each of these risks could result in damage to one of our pipeline systems, injuries to persons and property or business interruptions while any damaged pipeline is repaired or replaced, each of which could cause us to suffer a substantial loss of revenue and incur significant costs. In addition, if one of our pipeline systems were to experience a serious pipeline failure, a regulator could require us to conduct extensive testing of the entire pipeline system or upgrade segments of a pipeline unrelated to the failure, which costs may not be covered by insurance or recoverable through rate increases.

Our pipeline systems' may experience significant costs and liabilities related to pipeline integrity testing programs and any necessary pipeline repairs, or preventative or remedial measures have and may continue to cause significant costs and liabilities.

The DOT and PHMSA have 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 regulations require operators to perform ongoing assessments of pipeline integrity, identify applicable threats to pipeline segments that could affect HCAs, improve data collection and analysis, repair and remediate the pipeline as necessary and implement preventative and mitigating actions.

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, any failure to comply with the DOT and PHMSA regulations could subject our pipeline systems to penalties and fines.

The cost of additional integrity management requirements to our pipeline systems could have a material adverse effect on our results of operations or financial position and our ability to maintain current distribution levels.

Our pipeline systems' are regulated by federal, state and local laws and regulations that could impose costs for compliance with environmental protection.

Each of our pipeline systems are subject to federal, state and local environmental laws, regulations and enforcement policies and potential liabilities arising under or related to protection of the environment and natural resources.

Under certain environmental laws and regulations, we may be exposed to substantial liabilities for pollution or contamination that arise in connection with our operations. 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, 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. Moreover, new environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs or the cost of any remediation of environmental contamination that may become necessary, and these costs could be material.

Climate change legislation or regulations restricting emissions of GHG could result in increased operating costs and variable demand for the natural gas services we provide.

In December 2009, as a result of a United States Supreme Court decision, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to regulate GHG emissions under the CAA. Notably, the EPA has promulgated rules that monitor and regulate emissions of GHG from certain large stationary sources such as those found at pipeline compressor stations which became effective January 2, 2011. These rules are currently subject to a number of legal challenges which have been to date unsuccessful. In addition, certain states, some of which are in our areas of operation, have already taken legislative measures to reduce emissions of GHG.

The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emission control systems, to acquire emissions allowances or comply with new reporting requirements. Some proposed legislation and regulatory programs may not affect various segments of the energy industry uniformly. For example, increased GHG restrictions on the coal-fired power industry may result in increased dependency and demand on the natural gas industry. Any such legislation or regulatory programs could also change the cost of consuming, and thereby change demand for, natural gas that we transport. Consequently, any legislation and regulatory programs to reduce GHG emissions could impact demand for natural gas and adversely affect our financial position and results of operations.

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 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 pipeline systems. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain and comply with such approvals our pipeline systems could be prevented from operating or become subject to additional costs, resulting in potentially material adverse consequences to our results of operations.

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

As of December 31, 2011, $363.0 million of our total $742.5 million consolidated debt was subject 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 may increase or decrease our exposure to variable interest rates, but there is no assurance that these will be sufficient to offset rising interest rates.

For more information about our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk – Interest Rate Risk."

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

As of December 31, 2011, Great Lakes, Northern Border, GTN and Tuscarora had $373.0 million, $472.6 million, $325.0 and $30.1 million of debt outstanding, respectively. Of the debt outstanding, Great Lakes and Tuscarora have $19.0 million and $3.1 million of debt maturing in 2012, respectively. Their respective levels of debt could have important consequences to each of them, 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 cash to fund interest payments on the debt, reduces the funds that would otherwise be available for operations, future business opportunities and distributions to us;
- 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. GTN's debt provisions contain limitations on debt secured by liens and sale-leaseback transactions, as well as restrictions on GTN's debt to capitalization ratio. Under Tuscarora's debt instruments, Tuscarora granted a security interest in 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 our access to and cost of capital and credit.
We require regular access to capital and credit markets on acceptable terms in order to execute our business strategies, which include pursuing organic growth opportunities and accretive acquisitions and maximizing the value of our existing portfolio of pipeline systems. We also rely on access to capital and credit markets to meet our liquidity and capital resource requirements. Additionally, market conditions may impact our ability to access capital and credit markets for debt under reasonable terms. If conditions in the U.S. or global capital or credit markets undergo sustained volatility or significant deterioration, our cost of debt and equity capital could increase significantly and our access to capital markets could be adversely affected.

We do not own a controlling interest in Great Lakes, Northern Border, GTN or Bison, which limits our ability to control these assets to our benefit.
We do not own a controlling interest in Great Lakes, Northern Border, GTN or Bison, and are therefore unable to cause certain actions to occur without the agreement of the other owners. As a result, we may be unable to control the amount of cash distributions received from these assets or the cash contributions required to fund our share of their operations. The organizational documents of these assets require distribution of their available cash to their owners on a quarterly basis; however, in each case, available cash is reduced, in part, by appropriate reserves. Any disagreements with the other owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

We are subject to pipeline safety laws and regulations, compliance with which can require significant expenditures, can increase our cost of operations and may affect or limit our business plans.
Our pipeline systems are subject to pipeline safety regulations administered by the PHMSA. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate. Pipeline failures or failure to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by the PHMSA, which would reduce available capacity on our pipeline systems. Should any of these risks materialize, it could have a material adverse effect on our operations, financial condition, 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 must either obtain the right from landowners or exercise the power of eminent domain in order to use most of the land on which our pipelines are constructed and operated. 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 our financial condition, results of operations and cash flows.

RISKS INHERENT IN AN INVESTMENT IN THE PARTNERSHIP

Our indebtedness may limit our ability to obtain additional financing, making distributions or capitalizing on business opportunities. The conditions of the capital markets may adversely affect our ability to obtain credit or draw on our current credit facility.

As of December 31, 2011, the Partnership had $742.5 million of debt outstanding, including the revolving credit facility and Senior Notes. This 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 flexibility in responding to changing business and economic conditions may be limited.

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 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. These agreements require us to comply with various affirmative and negative covenants and maintain certain financial ratios. These restrictions and covenants include:

- entering into mergers, consolidations and sales of assets;
- granting liens;
- making material amendments to the Partnership's Second Amended and Restated Agreement of Limited Partnership (Partnership Agreement);
- incurring additional debt; and
- making distributions to unitholders.

Any future debt may contain similar restrictions.

Our ability to make cash distributions is 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 may cause the market price of our common units to decline.
An increase in interest rates may cause a corresponding decline in demand for equity investments, particularly yield-based equity investments such as our common units. Any such reduction in demand for our common units may cause the trading price of our common units to decline.

We do not have the same flexibility as corporations to accumulate cash and equity to protect against illiquidity in the future.
As a limited partnership, we are required by our Partnership Agreement 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 are not entitled to elect our General Partner or its board of directors.
The General Partner is our manager and operator. Unlike the stockholders in a corporation, holders of our common units have only limited voting rights on matters affecting our business. Unitholders have no right to elect our General Partner or its board of directors. The board of directors of our General Partner, including the independent directors, are appointed by its parent company and not by the unitholders.

As a result of these limitations, the price at which the common units will trade could be diminished because of the absence of a takeover premium in the trading price.

Even if unitholders are dissatisfied, they cannot initially remove our General Partner without its consent.
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 approximately 32 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.

As a result of these limitations, the price at which the common units will trade could be diminished because of the absence of a takeover premium in the trading price.

Our Partnership Agreement restricts voting and other rights of unitholders owning 20 percent or more of our common units.
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' ownership interests. 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, unless required by the NYSE;
- 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.

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 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.

A general partner generally has unlimited liability for the obligations of a limited partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law and conduct business in a number of other states. 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. Our unitholders could be liable for any and all of our obligations as if our unitholders were a general partner if a court or government agency 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.

In addition, under some circumstances, such as an improper cash distribution, 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 at any time our General Partner and its affiliates 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. As of December 31, 2011, the General Partner and its affiliates own approximately 32 percent of our outstanding common units.

TransCanada, through its subsidiaries, controls our General Partner, which has responsibility for conducting our business and managing our operations. 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 the 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. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. Such conflicts may include, among others, the following situations:

- our General Partner is allowed to take into account the interests of parties other than us, such as TransCanada and its affiliates, in resolving conflicts of interest;
- TransCanada, through wholly-owned subsidiaries, is the operator of all of our pipeline systems. This operator role along with its ownership interests in some of our pipeline systems may influence TransCanada to make decisions that may conflict as operator and/or owner of these systems;
- our General Partner and its affiliates are not limited in their ability to compete with us;
- some officers of our General Partner who provide services to us may also devote significant time to the business of TransCanada and may be compensated by TransCanada for the services rendered to it;
- our General Partner may limit our liability and reduce its 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
- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates.

Costs reimbursed to our General Partner are determined by our General Partner and may be substantial which could reduce our earnings and cash available for distribution.

Prior to making any distribution on the common units, we 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, 2011, we paid fees and reimbursements to our General Partner in the amount of $2.2 million (2010 – $2.2 million). Our General Partner in its sole discretion determines 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

Our tax treatment depends on our status as a partnership for federal income tax purposes. 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 taxes 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 or limited liability companies, 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 may be evaluating a variety of ways to subject partnerships to entity level taxation. 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.
Because unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash distributed, 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 distributions 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, Idaho, Illinois, Indiana, Iowa, Michigan, Minnesota, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, Texas, Washington, Wisconsin and Wyoming. 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 the location and general character of our principal physical properties is included in Item 1. "Business" and is incorporated herein by reference.

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 or lease sites for compressor stations, meter stations, pipeline field offices and microwave towers. Our pipeline systems are constructed and operated on land owned by third parties 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 is 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 is 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 was for a term which extended until April 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.

Item 3. Legal Proceedings

We are involved in various legal proceedings that arise in the ordinary course of business, as well as proceedings that we consider material under federal securities regulations. Information regarding certain GTN and Tuscarora proceedings described in Item 1. "Business – Government Regulation – FERC Rate Proceedings" is incorporated herein by reference. We are also a party to the following legal proceedings:

Great Lakes v. Essar Steel Minnesota LLC, et al. – On October 29, 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar Minnesota LLC and certain Essar affiliates (collectively, "Essar") for breach of contract. The proceeding relates to a transportation service agreement executed in September 2006 pursuant to which Great Lakes agreed to transport natural gas on a firm basis to a yet-to-be constructed facility of Essar for a term that started on July 1, 2009 and ends on March 31, 2024. Essar did not construct the facility and has refused to honor their contractual obligations, in particular required monthly payments. Great Lakes is seeking recovery of approximately $33.0 million for past and future payments due under the agreement. On May 25, 2010, Essar filed a counterclaim against Great Lakes and third party claims against the Partnership and several affiliates seeking a declaratory judgment delaying Essar's duty to perform under the agreement until the Essar facility is constructed and ready to accept delivery of natural gas. Essar also seeks recovery of approximately $0.6 million drawn by Great Lakes under a letter of credit based on a claim of conversion. The case is currently in the discovery phase.

State of South Dakota Use Tax Appeal – On February 28, 2011, the State of South Dakota assessed use tax in the amount of approximately $5.7 million on Northern Border for shipper supplied natural gas used to fuel compressors on Northern Border's pipeline system from July 1, 2007 to December 31, 2010. Northern Border recorded a liability of $7.4 million, including interest, in 2011 related to this matter. In November 2011, Northern Border filed a Request for Hearing with the South Dakota Department of Revenue to protest the assessment.

GTN and North Baja Pipeline v. Rolls-Royce Energy Systems, Inc. – On July 27, 2009, North Baja and GTN filed an arbitration proceeding with American Arbitration Association in Portland, Oregon seeking approximately $26 million in damages related to performance, integrity and reliability issues associated with certain equipment purchased from Rolls Royce Energy Systems, Inc. (RREI). GTN and North Baja allege that equipment purchased from RREI in 2001 is defective and that RREI breached its contract and warranties. The arbitration is in the discovery phase. We cannot determine the outcome of this proceeding or the amount of any potential recovery, if any. In the event of a recovery, GTN will not receive any portion of the award due to the assignment of its rights to recovery to an affiliate.

EPA Request for Information under CAA – 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 response to the EPA and subsequently responded to a request from the EPA dated July 26, 2010 on information regarding one natural gas compressor station located in Minnesota. In May 2011, the EPA required Great Lakes to provide additional information regarding a natural gas compressor station located in Minnesota, as well as information regarding other natural gas compressor stations in the states of Minnesota and Michigan. The potential effects on Great Lakes that may arise as a result of this information request or the underlying compliance review are not determinable at this time.

PART II

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

As of February 21, 2012, there were 63 registered holders of common units and approximately 23,644 beneficial owners of common units, including common units held in street name. Our common units were listed on the NASDAQ Global Select Market (NASDAQ) under the symbol "TCLP" from May 1999 to December 11, 2011. On December 12, 2011, our common units commenced trading on the NYSE under the new symbol "TCP."

We currently have 53,472,766 common units outstanding, of which 36,387,935 are held by the public, 11,287,725 are held by TransCan Northern Ltd. (TransCan Northern), an indirect wholly-owned subsidiary of TransCanada and 5,797,106 are held by our General Partner. The common units represent a 98 percent limited partner interest. Our General Partner holds an aggregate two percent general partner interest.

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

	Price Range		Cash Distributions Declared per Common Unit
	High	Low	
2011			
First Quarter	**$54.95**	**$50.02**	**$0.750**
Second Quarter	**$52.55**	**$43.24**	**$0.770**
Third Quarter	**$49.04**	**$39.24**	**$0.770**
Fourth Quarter	**$48.36**	**$41.61**	**$0.770**
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

On February 14, 2012, we paid a cash distribution of $42.0 million to unitholders and the General Partner, representing a cash distribution of $0.77 per common unit for the quarter ended December 31, 2011. The distribution was allocated in the following manner: $41.2 million to the unitholders as of the close of business on January 31, 2011 (including $4.5 million to the General Partner as holder of 5,797,106 common units and $8.7 million to TransCanada as indirect holder of 11,287,725 common units), and $0.8 million to the General Partner in respect of its two percent general partner interest. In 2011, the Partnership made cash distributions to unitholders and the General Partner that amounted to $154.8 million compared to $138.7 million in 2010.

Cash Distribution Policy

Pursuant to the Partnership Agreement, 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. Our quarterly cash distributions to the unitholders comprise all of our Available Cash. Available Cash is defined in the Partnership Agreement and generally means, with respect to any quarter, 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 our business (including reserves for future capital expenditures and for anticipated credit needs);

- comply with applicable laws or any debt instrument or other agreement to which we are subject; and
- provide funds for cash distributions to unitholders and the General Partner in respect of any one or more of the next four quarters.

Incentive Distributions
The incentive distribution provisions of the Partnership Agreement 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 2011 and 2010, we paid no incentive distributions to our General Partner.

Additional information about our cash distributions is included in Item 7. "Managements Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources" and Item 13. "Certain Relationships and Related Transactions, and Director Independence."

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)	**2011[a]**	2010	2009[b]	2008[b]	2007[b][c]
Income Data (for the year ended December 31)					
Equity income from unconsolidated affiliates	**153.5**	126.0	99.4	122.6	110.2
Transmission revenues	**70.4**	69.1	67.9	64.5	49.8
Financial charges and other	**(28.0)**	(25.6)	(29.3)	(34.6)	(38.7)
Net income	**157.4**	137.1	106.1	123.0	94.7
Basic and diluted net income per common unit	**$3.02**	$2.91	$2.34	$2.73	$2.48
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$3.060**	$2.960	$2.895	$2.815	$2.630
Balance Sheet Data (at December 31)					
Total assets	**2,082.0**	1,650.5	1,675.1	1,701.1	1,732.4
Long-term debt (including current maturities)	**742.5**	513.9	541.3	536.8	573.4
Partners' equity	**1,333.0**	1,112.5	1,103.5	875.6	900.1

(a) 2011 net income includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

(b) The acquisition of North Baja from TransCanada in July 2009 was accounted for as a transaction between entities under common control, 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.

(c) The Partnership acquired a 46.45 percent interest in Great Lakes on February 22, 2007.

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

Management's Discussion and Analysis is intended to give our unitholders an opportunity to view the Partnership through the eyes of our management. We have done so by providing management's current assessment of, and outlook of the business of the Partnership. Our discussion and analysis includes the following:

- EXECUTIVE OVERVIEW;
- HOW WE EVALUATE OUR OPERATIONS;
- RESULTS OF OPERATIONS;
- LIQUIDITY AND CAPITAL RESOURCES;
- CRITICAL ACCOUNTING ESTIMATES;
- CONTINGENCIES; and
- RELATED PARTY TRANSACTIONS.

The following discussion and analysis should be read in conjunction with Item 8. "Financial Statements and Supplementary Data."

EXECUTIVE OVERVIEW

We earned $157.4 million or $3.02 per unit in 2011 compared to $137.1 million or $2.91 per unit in 2010. With the addition of the GTN and Bison pipelines, which are both underpinned by long-term contracts, we grew our asset base by 26 percent to $2.1 billion in 2011. Cash distributions paid increased 16 percent to $154.8 million while distributable cash flow also increased 23 percent to $222.4 million creating a solid foundation for sustainable future cash distributions. Excluding the $20 million one-time cash distribution from GTN, our cash distribution coverage ratio remained solid with 1.31 times coverage.

In May 2011, we acquired a 25 percent membership interest in each of GTN and Bison from subsidiaries of our sponsor, TransCanada, for a total purchase price of $605 million. Both pipelines are backed by long-term contracts which are expected to increase the stability of our revenues and cash flow.

In May 2011, we raised net proceeds of $337.6 million in a 7.3 million, common unit equity offering associated with the GTN and Bison acquisitions. In June 2011, we raised $350.0 million through the issuance of long-term debt at a 4.65 percent coupon rate in our first public debt offering. In July 2011, we amended our revolving credit and term loan agreement (Senior Credit Facility) increasing the revolving credit facility to $500 million plus a $250 million accordion feature that is subject to lenders approval. As of December 31, 2011, we had no amounts hedged by interest rate swaps.

In November 2011, GTN received approval of the GTN Settlement from the FERC effective January 1st, 2012. GTN's new rates are higher than its previous rates however, because of lower contracted capacity GTN's 2012 revenue could be lower than 2011 by as much as approximately $5 million, potentially offset by additional sales of discretionary volumes.

In December 2011, Tuscarora filed a settlement agreement with the FERC that, if approved, will resolve a challenge to its currently effective rates. The agreement is subject to FERC approval and is expected to reduce Tuscarora's revenue by approximately $6.0 million relative to 2011. Net income is expected to be reduced by $3 million as a result of lower depreciation rates and the lower revenue.

Great Lakes continues to experience a trend towards shorter term transportation contract periods. Since November 1, 2010, Great Lakes' largest shipper, TransCanada PipeLines Limited (TCPL), has reduced its forward long-haul commitment from approximately 1,300 MDth/d to 673 MDth/d as of November 1, 2011. The contractual commitment will reduce to 100 MDth/d as of November 1, 2012. At the same time, TCPL increased their annual backhaul contract volumes from 313 MDth/d currently to 474 MDth/d effective November 1, 2012.

Factors That Impact Our Business

Supply

The primary source of natural gas transported by our pipeline systems, excluding Bison and North Baja is the WCSB. However, our pipeline systems have other available sources of supply, including Rocky Mountain natural gas available to Tuscarora through its connection to the Ruby pipeline. Gas exiting the WCSB is dependent upon natural gas production levels, demand for natural gas in Western Canada, including increased demand from the oilsands and the volume of natural gas injected into natural gas storage in Western Canada. Despite declines in conventional drilling activity in the WCSB in recent years, we expect drilling from the lower cost unconventional resources, including shale gas and tight gas, to increase. The ultimate supply potential of the WCSB has improved due to access to developing unconventional resources. In particular, the Horn River and Montney shale plays have demonstrated encouraging results which are expected to improve supply available from the WCSB in 2012 and beyond. In the longer term, reserves from northern natural gas may increase the supply coming out of the WCSB. Due to growth in unconventional production, the total WCSB production increased slightly in 2011 and is expected to also show modest growth in 2012.

Demand

Prevailing market conditions and dynamic competitive factors in North America, including increasing shale gas production in the U.S., have and 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.

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 2011 remained relatively flat compared to 2010 levels. Despite a slight rebound in economic activity, factors such as weather and strong hydroelectric generation in western markets limited the amount of natural gas demand in 2011. Natural gas demand in 2012 is anticipated to grow with the economic recovery and also increase due to the expectation of a low gas price environment and a return to normal hydroelectric conditions. In the longer term, it is expected that demand for natural gas will continue to improve modestly with the majority of the growth in demand resulting from increased demand for natural gas-fired electric power generation and for use in the industrial sector.

Competition

Due to excess pipeline capacity, there is currently increased competition amongst natural gas pipelines for the transportation of gas exiting the WCSB and other supply regions served by our pipeline systems.

Contracting

The majority of revenue from GTN, Bison, North Baja and Tuscarora is underpinned by long-term contracts. Great Lakes and Northern Border have a combination of long-term and short-term contracts as well as portions of available capacity.

Historically, our revenues have been stable due to our portfolio of long-term firm contracts. Our financial results in the future will be subject to changes in supply and demand, regulatory actions in regards to the rates charged to customers, and the trend toward short-term contracts. The demand for transportation services on our pipeline systems is dependant on numerous factors including the level of supply and demand for natural gas, weather, natural gas storage inventory levels, the price of natural gas, and the general strength of the economy.

Outlook of Our Business

Our pipelines' operating results may be impacted by expiration of long-term contracts, competition for supply, the price of supply, and decisions regarding rate proceedings that affect rates in 2012 and beyond. The revenues for our pipeline systems are subject to FERC approval or settlements affecting existing rates. Revenue beyond 2012 for Northern Border will be impacted by the rates established in a rate case that it is required to file on or before December 31, 2012. The rates established in the rate case will reflect Northern Border's rate base, revenue requirement, depreciation and contract levels at the time of the filing. These factors could result in a change in the rates charged by Northern Border beginning in 2013 and beyond.

Although Great Lakes has historically been fully contracted, Great Lakes currently has approximately 75 percent of its long-haul capacity contracted through to October 31, 2012. Great Lakes' ability to sell its current and future available capacity will depend on future market conditions which are impacted by a number of factors including, weather for the remainder of the winter and into the summer months, levels of natural gas in storage, the price of natural gas liquids and the associated impact to North American natural gas production, and the level of the Mainline's tolls.

As a result of recent re-contracting activity, Northern Border's long-haul capacity is substantially contracted through March 2013.

GTN, Bison, North Baja, and Tuscarora are expected to provide relatively stable revenues as the contracted capacity on these pipelines are primarily underpinned by long-term firm contracts.

Our floating rate debt is subject to changes in interest rates. Based on our expectation of interest rates and debt levels of the Partnership, we expect to realize lower financial charges in the next 12 months.

HOW WE EVALUATE OUR OPERATIONS

We evaluate our business primarily on the basis of the underlying operating results for each of our pipeline systems, along with a measure of Partnership cash flows. This measure does not have any standardized meaning prescribed by U.S. generally accepted accounting principles (GAAP). It is, therefore, considered to be a non-GAAP measure and is unlikely to be comparable to similar measures presented by other entities. Partnership cash flows include cash distributions from the Partnership's equity investments, Great Lakes, Northern Border, GTN and Bison plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja and Tuscarora, net of Partnership costs and distributions declared to the General Partner. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – LIQUIDITY AND CAPITAL RESOURCES – Partnership Cash Flows".

RESULTS OF OPERATIONS

Our general partner interests in Great Lakes, Northern Border, GTN and Bison, and ownership of North Baja and Tuscarora were our only material sources of income in 2011. 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, GTN, Bison, 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, 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.

Partnership Results of Operations

(millions of dollars)	**2011**	2010	2009
Equity earnings:			
Great Lakes	**59.5**	58.7	59.1
Northern Border	**75.5**	67.3	40.3
GTN[a]	**11.5**	–	–
Bison[a]	**7.0**	–	–
Net income from Other Pipes[b][c]	**40.9**	36.9	28.0
Partnership expenses	**(37.0)**	(25.8)	(29.6)
Net income prior to recast	**157.4**	137.1	97.8
North Baja's contribution prior to acquisition	**–**	–	8.3
Net Income	**157.4**	137.1	106.1

(a) Represents equity earnings from May 3, 2011, date of acquisition, to December 31, 2011.

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

(c) The acquisition of North Baja from TransCanada in July 2009 was accounted for as a transaction between entities under common control, 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.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

Net income increased $20.3 million to $157.4 million in 2011 compared to $137.1 million in 2010. This increase was primarily due to higher equity income from Northern Border, earnings from the 25 percent membership interests in GTN and Bison, which were acquired in May 2011, and higher net income from Other Pipes partially offset by higher Partnership expenses.

Equity income from Great Lakes was $59.5 million in 2011, an increase of $0.8 million compared to 2010. The increase in equity income was primarily due to the cumulative impact of a Michigan tax law change eliminating Michigan Business Tax (MBT) at the partnership level and the positive impact to earnings from depreciation rate reductions arising from the Section 5 rate case settlement in May 2010. These increases were partially offset by decreased transmission revenues resulting from unsold capacity and by higher operating expenses.

Equity income from Northern Border was $75.5 million in 2011, an increase of $8.2 million compared to 2010. The increase in equity income was primarily due to increased revenue from transportation sales.

Net income from Other Pipes, which includes results from North Baja and Tuscarora, was $40.9 million in 2011, an increase of $4.0 million compared to 2010. This increase was primarily due to lower financial charges from Tuscarora as a result of lower average debt outstanding and lower average interest rates attributable to the refinancing of a portion of senior notes in December 2010 and higher revenues from North Baja due to the Yuma Lateral, which was completed in March 2011.

Costs at the Partnership level increased $11.2 million to $37.0 million in 2011 compared to 2010. This increase was primarily due to costs incurred relating to the GTN and Bison acquisitions along with higher financial charges in 2011 resulting from higher average debt outstanding.

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, higher net income from Other Pipes and lower Partnership expenses.

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 Great Lakes Settlement and by lower operating expenses.

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.

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.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity include distributions received from our investments in unconsolidated affiliates, operating cash flows from North Baja and Tuscarora, public offerings of debt and equity 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.

We expect to be able to fund our liquidity requirements over the next twelve months. The reduction in long-term firm contracts underpinning revenues on Great Lakes beyond 2012 is consistent with the industry trend towards short-term contracting, and may result in lower or volatile revenues. Management cannot estimate the impact this will have on cash flows.

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, Northern Border, GTN and Bison, 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)*	**2011**	2010	2009
Net income[a][b]	**157.4**	137.1	106.1
North Baja's contribution prior to acquisition[b]	**–**	–	(8.3)
Net income prior to recast	**157.4**	137.1	97.8
Add:			
Cash distributions from Great Lakes[c]	**72.9**	69.2	72.5
Cash distributions from Northern Border[c]	**99.1**	86.0	75.7
Cash distributions from GTN[c]	**32.6**	–	–
Cash distributions from Bison[c]	**5.6**	–	–
Cash flows provided by Other Pipes' operating activities	**52.3**	53.5	39.4
	262.5	208.7	187.6
Less:			
Equity earnings from unconsolidated affiliates	**(153.5)**	(126.0)	(99.4)
Other Pipes' net income	**(40.9)**	(36.9)	(28.0)
	(194.4)	(162.9)	(127.4)
Partnership cash flows before General Partner distributions	**225.5**	182.9	158.0
General Partner distributions[d]	**(3.1)**	(2.8)	(7.8)
Partnership cash flows	**222.4**	180.1	150.2
Cash distributions declared	**(161.4)**	(139.6)	(123.6)
Cash distributions declared per common unit[e]	**$3.060**	$2.960	$2.895
Cash distributions paid	**(154.8)**	(138.7)	(117.0)
Cash distributions paid per common unit[e]	**$3.040**	$2.940	$2.870

[a] Includes equity earnings of GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

[b] The acquisition of North Baja from TransCanada in July 2009 was accounted for as a transaction between entities under common control, 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.

[c] In accordance with the cash distribution policies of the respective pipeline systems, cash distributions from Great Lakes, Northern Border, GTN and Bison are based on their respective prior quarter financial results. In fourth quarter 2011, GTN distributed $4.9 million and $7.7 million for the second and third quarters, respectively. In addition, in fourth quarter 2011, GTN paid a one-time distribution of $20.0 million related to its cash balance at the time of acquisition.

[d] 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. Incentive distributions in 2011, 2010, and 2009 were nil, nil and $5.3 million, respectively.

[e] 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, 2011 Compared with the Year Ended December 31, 2010

Partnership cash flows increased $42.3 million to $222.4 million in 2011 compared to $180.1 million in 2010. This increase was primarily due to a $20.0 million one-time cash distribution from GTN, increased cash distributions from Great Lakes of $3.7 million and Northern Border of $13.1 million, and cash distributions from GTN and Bison of $12.6 million and $5.6 million, respectively, for the second and third quarters, partially offset by higher costs at the Partnership level of $11.2 million relating to the acquisitions of 25 percent membership interests in GTN and Bison, including higher financial charges.

The Partnership paid cash distributions of $154.8 million in 2011, an increase of $16.1 million compared to 2010, due to an increase in the number of common units outstanding resulting from the May 2011 equity offering, an increase in the quarterly distribution of $0.02 per common unit paid beginning in the fourth quarter of 2010, and a further increase of $0.02 per common unit paid in the third quarter of 2011.

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 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 cash 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.

Other Cash Flows

On May 3, 2011, the Partnership acquired 25 percent membership interests in GTN and Bison with net proceeds from an equity issuance of $330.9 million, draws on a bridge loan facility and senior revolving credit facility of $61.0 million and $125.0 million, respectively, a $6.7 million capital contribution from the General Partner and cash on hand. In 2011, North Baja and Tuscarora made capital expenditures of $1.1 million, of which the majority was spent on routine maintenance on computer hardware and software. Also in 2011, the Partnership made equity contributions of $8.8 million to Great Lakes to fund debt repayments, a $49.8 million equity contribution in accordance with Northern Border's distribution policy in order to meet minimum equity to total capitalization requirements, and an equity contribution of $5.0 million to fund Northern Border's Princeton Lateral project. Pursuant to an amendment to the acquisition agreement between the Partnership and TransCanada, in 2011 the Partnership made an additional payment of $2.4 million in connection with the North Baja Yuma Lateral for the additional contract secured by TransCanada when the facilities associated with the additional contract were completed.

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 our then existing 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 our revolving portion of our then existing senior credit facility.

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2011 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Senior Credit Facility due 2016	363.0	–	–	363.0	–
4.65% Senior Notes due 2021	349.4	–	–	–	349.4
6.89% Series C Senior Notes due 2012	3.1	3.1	–	–	–
3.82% Series D Senior Notes due 2017	27.0	–	10.8	16.2	–
Interest payments on Senior Notes	159.7	17.5	51.6	33.6	57.0
Operating leases	3.4	0.2	0.4	0.3	2.5
	905.6	20.8	62.8	413.1	408.9

The Partnership's Debt and Credit Facilities

The Partnership's Senior Credit Facility consists of a $500.0 million senior revolving credit facility with a banking syndicate, maturing July 13, 2016, under which $363.0 million was outstanding at December 31, 2011 (2010 – $8.0 million). At December 31, 2010 the Senior Credit Facility also included a $475.0 million senior term loan of which $175.0 million was repaid on June 17, 2011 and the remaining $300.0 million was repaid on December 12, 2011.

On July 13, 2011, the Partnership closed an amendment to its Senior Credit Facility increasing the senior revolving credit facility from $250.0 million to $500.0 million, and extending the maturity date of the senior revolving credit facility to July 2016 from December 2011. At the Partnership's option, the interest rate on the outstanding borrowings under the senior revolving credit facility may be the lenders' base rate or the LIBOR plus, in either case, an applicable margin that is based on the Partnership's long-term unsecured credit ratings. The Senior Credit Facility permits the Partnership to specify the portion of the borrowings to be covered by specific interest rate options and, for LIBOR-based borrowings, to specify the interest rate period. The Partnership is required to pay a commitment fee based on its credit rating and on the unused principal amount of the commitments under the senior revolving credit facility. The senior revolving credit facility has a feature whereby at any time, so long as no event of default has occurred and is continuing, the Partnership may request an increase in the senior revolving credit facility of up to $250.0 million, but no lender has any obligation to increase their respective share of the facility.

The interest rate on the Senior Credit Facility averaged 0.86 percent for the year ended December 31, 2011 (2010 – 0.91 percent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.07 percent for the year ended December 31, 2011 (2010 – 4.30 percent). Prior to hedging activities, the interest rate was 1.65 percent at December 31, 2011 (2010 – 0.83 percent). No interest rate hedges are currently in place.

On June 17, 2011, the Partnership closed a $350.0 million public debt offering of 10-year, senior unsecured notes with an interest rate of 4.65 percent. Proceeds were used to repay funds borrowed under the Partnership's bridge loan facility and to partially repay borrowings under our then existing Senior Credit Facility. The senior notes mature June 15, 2021. The indenture for the notes contains customary investment grade covenants.

On May 3, 2011, the Partnership entered into an agreement with SunTrust Robinson Humphrey, Inc., as Arranger, for a 364-day senior unsecured bridge loan facility for up to $400.0 million to fund the Acquisitions. Borrowings under the bridge loan facility bore interest based, at the Partnership's election, on the lenders base rate or the LIBOR plus, in either case, an applicable margin. On May 3, 2011, the Partnership drew $61.0 million to partially fund the Acquisitions. Please see Note 5 in the financial statements for more details on the Acquisitions. On June 17, 2011, the Partnership repaid the $61.0 million draw, and the bridge loan facility was cancelled. The interest rate on the loans made under bridge loan facility was 1.7 percent.

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, and depreciation and amortization expense less equity earnings and extraordinary gains)) of no more than 5.00 to 1.00 at the end of each fiscal quarter. The permitted leverage ratio will increase to 5.50 to 1.00 for the fiscal quarter in which a specified material acquisition occurs and for the two fiscal quarters immediately following such acquisition, after which the permitted leverage ratio reverts to 5.00 to 1.00. The Senior Credit Facility contains additional covenants that include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurrence of additional debt by the Partnership's subsidiaries and distributions to unitholders. Upon any breach of these covenants, amounts outstanding under the Senior Credit Facility may become immediately due and payable. At December 31, 2011, the Partnership was in compliance with its financial covenants.

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, 2011 was $763.4 million (2010 – $513.9 million). As of February 28, 2012, the Partnership had $332.0 million outstanding under the $500.0 million senior revolving credit facility, which expires in July 2016.

Interest Rate Swaps and Options

The Partnership's long-term debt results in exposures to changing interest rates. The Partnership generally uses derivatives to assist in managing its exposure to interest rate risk. As of December 31, 2011, however, we have no derivatives in place.

The interest rate swaps and options were structured such that the cash flows matched those of the Senior Credit Facility. There were no amounts hedged at December 31, 2011 (2010 – $375.0 million). $300.0 million of variable-rate debt was hedged by an interest rate swap through December 12, 2011, where the weighted average fixed interest rate paid was 4.89 percent. $75.0 million of variable-rate debt was hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid was 3.86 percent. In addition to these fixed rates, the Partnership paid 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, 2011, the fair value of the interest rate swaps accounted for as hedges was nil (2010 – $13.8 million current liability). In 2011, the Partnership recorded interest expense of $13.6 million on the interest rate swaps and options (2010 – $16.5 million; 2009 – $15.1 million).

Capital Requirements

The Partnership is expected to make equity contributions totaling $8.8 million to Great Lakes in 2012 for scheduled debt repayments.

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

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).

2011 Fourth Quarter Cash Distribution

On January 17, 2012, the board of directors of our General Partner declared the Partnership's fourth quarter 2011 cash distribution in the amount of $0.77 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2012 to unitholders of record as of January 31, 2012, totaled $42.0 million and was paid in the following manner: $41.2 million to common unitholders (including $4.5 million to the General Partner as holder of 5,797,106 common units and $8.7 million to TransCanada as holder of 11,287,725 common units) and $0.8 million to the General Partner in respect of its two percent general partner interest. The fourth quarter 2011 cash distribution represents an annual cash distribution of $3.08 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 expiration of long-term firm contracts on Great Lakes in November 2012 and the industry trend towards short-term contracting may result in lower or volatile operating cash flow from Great Lakes. This may impact Great Lakes' ability to fund their liquidity requirements including making distributions to their partners. Management cannot estimate the impact this will have on cash flows.

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 of December 31, 2011 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.73% series Senior Notes due 2012 to 2018	63.0	9.0	27.0	18.0	9.0
9.09% series Senior Notes due 2012 to 2021	100.0	10.0	30.0	20.0	40.0
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	269.7	28.7	77.2	43.9	119.9
	642.7	47.7	134.2	81.9	378.9

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 $201.0 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2011 (2010 – $211.0 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2011.

The aggregate estimated fair value of Great Lakes' long-term debt was $541.2 million for 2011 (2010 – $518.2 million). The aggregate annual required repayment of senior notes is $19.0 million for each year 2012 through 2016. In 2011, interest expense related to Great Lakes' senior notes was $29.9 million (2010 – $31.4 million; 2009 – $32.9 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 of December 31, 2011 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.24% Senior Notes due 2016	100.0	–	–	100.0	–
7.50% Senior Notes due 2021	250.0	–	–	–	250.0
$200 million Credit Agreement due 2016	123.0	–	–	123.0	–
Interest payments on debt	227.1	27.1	81.3	43.7	75.0
Operating leases	63.0	1.9	5.7	4.4	51.0
Other long-term obligations	2.6	2.6	–	–	–
	765.7	31.6	87.0	271.1	376.0

Interest Payments on Credit Agreement
The interest rate at December 31, 2011 of 1.60 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.

Credit Agreement
On November 16, 2011, Northern Border entered into a $200 million amended and restated revolving Credit Agreement (2011 Credit Agreement) with certain financial institutions. The 2011 Credit Agreement was used to refinance the outstanding indebtedness under the pre-existing $250 million revolving credit agreement dated as of April 27, 2007. At December 31, 2011, $123.0 million was outstanding leaving $77.0 million available for future borrowings. At Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or the LIBOR plus, in either case, an applicable margin that is based on Northern Border's long-term unsecured credit ratings. The term of the 2011 Credit Agreement is five years.

At December 31, 2011, Northern Border was in compliance with all of its financial covenants.

The fair value of Northern Border's variable-rate debt was approximately the same as its carrying value since the interest rates are periodically adjusted to reflect current market conditions. As of December 31, 2011, Northern Border's outstanding borrowings under its credit agreement were $123 million. The average interest rate on Northern Border's Credit Agreement at December 31, 2011 was 1.60 percent (2010 – 0.54 percent).

Senior Notes
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, 2011, Northern Border was in compliance with all of its financial covenants.

At December 31, 2011, the aggregate estimated fair value of the outstanding senior notes was approximately $541.0 million (2010 – $599.0 million). In 2011, interest expense related to the senior notes was $25.0 million (2010 – $25.0 million; 2009 – $31.3 million).

Summary of GTN's Contractual Obligations

GTN's contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2011 included the following:

		Payments Due by Period			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
5.09% Senior Notes due 2015	75.0	–	75.0	–	–
5.29% Senior Notes due 2020	100.0	–	–	–	100.0
5.69% Senior Notes due 2035	150.0	–	–	–	150.0
Operating leases	3.4	0.5	1.7	0.5	0.7
Interest payments on long term debt	256.8	17.6	50.7	27.7	160.8
	585.2	18.1	127.4	28.2	411.5

The 2005 Note Purchase Agreement contains a covenant that limits total debt to no greater than 70 percent of total capitalization. At December 31, 2011, the total debt to total capitalization ratio was 39 percent.

GTN was in compliance with all terms and conditions of all its credit and other debt agreements at December 31, 2011.

Other
GTN has a cash management agreement with TransCanada whereby GTN's funds are pooled with other TransCanada affiliates. The agreement gives GTN the ability to obtain short-term borrowings to provide liquidity for GTN's operating needs.

Summary of Bison's Contractual Obligations

Bison had commitments of $12.4 million as of December 31, 2011 in connection with reclamation and restoration work associated with the construction of the pipeline.

Other
Bison has a cash management agreement with TransCanada whereby Bison's funds are pooled with other TransCanada affiliates. The agreement gives Bison the ability to obtain short-term borrowings to provide liquidity for Bison's operating needs.

Cash From Our Pipeline Systems

Cash Distribution Policies of Great Lakes, Northern Border, GTN and Bison

Distributions of available cash are made to partners on a pro rata basis according to each partner's ownership percentage, approximately one month following the end of a quarter. Great Lakes, Northern Border, GTN and Bison'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, Northern Border, GTN and Bison'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 on earnings before income taxes, depreciation and allowance for funds used during construction (AFUDC) less capital expenditures, debt repayments not funded with cash calls to its partners, and current MBT. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

Northern Border's 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.

GTN and Bison's distribution policies are to distribute 100 percent of distributable cash flow based on earnings before depreciation and amortization less AFUDC and maintenance 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.

Great Lakes declared its fourth quarter 2011 distribution of $23.3 million on January 11, 2012, of which the Partnership received its 46.45 percent share, or $10.8 million. The distribution was paid on February 1, 2011.

Northern Border declared and paid its fourth quarter 2011 distribution of $50.0 million on February 1, 2012, of which the Partnership received its 50 percent share, or $25.0 million.

GTN declared and paid its fourth quarter 2011 distribution of $21.4 million on February 1, 2012, of which the Partnership received its 25 percent share, or $5.4 million.

Bison declared its fourth quarter 2011 distribution of $15.6 million on January 11, 2012, of which the Partnership received its 25 percent share, or $3.9 million. The distribution was paid on February 1, 2012.

Investing Activities for our Pipeline Systems

Total 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)*	**2011**	2010	2009
Great Lakes:			
Maintenance	**9.0**	8.0	5.9
Growth	**2.4**	6.0	2.6
Great Lakes' capital spending	**11.4**	14.0	8.5
Northern Border:			
Maintenance	**16.8**	5.4	6.7
Growth	**12.9**	4.5	4.4
Northern Border's capital spending	**29.7**	9.9	11.1
GTN[(a)]:			
Maintenance	**12.7**	–	–
Growth	**0.8**	–	–
GTN's capital spending	**13.5**	–	–
Bison[(a)]:			
Maintenance	**0.8**	–	–
Growth	**40.4**	–	–
Bison's capital spending	**41.2**	–	–
North Baja:			
Maintenance	**0.3**	0.2	0.3
Growth	**0.4**	8.9	0.8
North Baja's capital spending	**0.7**	9.1	1.1
Tuscarora:			
Maintenance	**0.4**	0.2	0.2
Growth	**–**	–	0.6
Tuscarora's capital spending	**0.4**	0.2	0.8

(a) Represents capital spending from May 3, 2011, date of acquisition, to December 31, 2011.

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

Great Lakes incurred growth capital expenditures of $2.4 million in 2011 primarily related to the installation of additional gas separation capability in order to achieve increased operational deliveries to Great Lakes at Farwell. Growth capital expenditures incurred in 2010 and 2009 of $6.0 million and $2.6 million, 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 2011 through 2009 of $9.0 million, $8.0 million and $5.9 million, respectively, were comprised of maintenance capital projects including compressor engine overhauls and pipeline integrity program costs. In 2012, Great Lakes expects to invest approximately $10.4 million for maintenance capital expenditures, of which the Partnership's share is $4.8 million. No significant growth capital expenditures are planned for 2012.

Northern Border incurred growth capital expenditures of $12.9 million in 2011 and $4.5 million in 2010, primarily related to the Princeton Lateral Project, while growth expenditures of $4.4 million in 2009 were primarily related to spending for the Des Plaines Project. The maintenance capital expenditures of Northern Border in 2011 through 2009 of $16.8 million, $5.4 million and $6.7 million, respectively, were comprised of maintenance capital projects including compressor engine overhauls. In 2012, Northern Border expects to spend approximately $23.4 million for capital expenditures, of which the Partnership's share is $11.7 million. The Partnership's share of maintenance capital expenditures is estimated to be $10.9 million and include renewals and replacements of existing facilities. In 2012, Northern Border expects to spend approximately $1.6 million for growth capital expenditures related to the Princeton Lateral Project.

From May 3, 2011, date of acquisition, to December 31, 2011, GTN incurred $13.5 million of capital expenditures primarily related to compressor station maintenance and pipeline integrity program costs. In 2012, GTN expects to spend approximately $21.7 million for maintenance capital expenditures, primarily related to compressor station maintenance and pipe integrity program costs. $3.5 million of growth capital expenditures are planned for 2012 relating to the Carty Lateral. In 2012, the Partnership's share of GTN's maintenance and growth capital is expected to be approximately $5.4 million and $0.9 million, respectively.

From May 3, 2011, date of acquisition, to December 31, 2011, Bison incurred $41.2 million of capital expenditures primarily related to the completion of the Bison pipeline and the in-service failure. In 2012, Bison expects to spend approximately $0.3 million for maintenance capital expenditures, primarily related to pipe integrity program costs. In 2012, $6.5 million of construction close-out capital expenditures are expected, of which the Partnership's share is approximately $1.6 million.

In 2011, North Baja incurred $0.3 million of capital expenditures primarily related to routine pipeline maintenance and integrity costs and $0.4 million of growth capital. 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 2012, North Baja expects to spend approximately $0.1 million for capital expenditures, primarily related to pipe integrity program costs and system pipeline improvements. No significant growth capital expenditures are planned for 2012.

In 2011, Tuscarora incurred $0.4 million of capital expenditures related to routine maintenance of computer hardware and software. Tuscarora's 2010 capital expenditures of $0.2 million primarily related to the replacement of meter station regulators and batteries. Tuscarora's 2009 capital expenditures of $0.8 million related to the replacement of electric system components at various compressor stations and to the Likely compressor station expansion. In 2012, Tuscarora expects to spend approximately $1.4 million for maintenance capital expenditures, primarily related to pipe integrity program costs and system pipeline improvements. No significant growth capital expenditures are planned for 2012.

CRITICAL ACCOUNTING 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, Northern Border, GTN and Bison 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, Northern Border, GTN and Bison because of our ownership interests and our representation on their 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 the balance sheets of our pipelines systems. If it is determined that future recovery of these assets is no longer probable as a result of discontinuing application of ASC 980 or other regulatory actions, our pipelines systems would be required to write off the regulatory assets at that time.

As of December 31, 2011, Northern Border reflected regulatory assets of $28.2 million on its balance sheet (2010 – $20.3 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. Northern Border also had regulatory liabilities of $12.1 million as of December 31, 2011 (2010 – $9.6 million).

As of December 31, 2011, GTN had regulatory assets of $2.4 million and regulatory liabilities of $18.6 million.

As of December 31, 2011, Tuscarora has no regulatory assets (2010 – nil) and $0.2 million in regulatory liabilities (2010 – $0.5 million).

As of December 31, 2011 and 2010, Great Lakes, Bison 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 expected to be generated by that asset or asset group 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 determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals as considered necessary.

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, 2011 and 2010, 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, 2011.

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 – Regulatory Environment" for additional information.

Climate Change

The regulation or restriction of GHG emissions could result in changes to the consumption and demand for natural gas. This could have adverse effects on our pipeline systems, 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 GHG 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 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.

RELATED PARTY TRANSACTIONS

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts, some of which are provided at discounted rates and some at maximum recourse rates. The contracts are on the same terms as would be available to other shippers and have remaining terms ranging from one to six years. Great Lakes earned $80.6 million of transportation revenues under these contracts in 2011 (2010 – $148.5 million; 2009 – $141.7 million). This amount represents 32.2 percent of total revenues earned by Great Lakes in 2011 (2010 – 56.6 percent; 2009 – 48.9 percent). The year over year differences come from a combination of capacity reduction of 27 percent and an increase in TransCanada's capacity release activity on its remaining contracts, which shifted revenues from those remaining contracts from the affiliates to other customers who took up the released capacity. Great Lakes also earned $1.3 million in affiliated rental revenue in 2011 (2010 – $0.9 million; 2009 – $0.6 million).

Revenue from TransCanada and its affiliates of $38.0 million is included in the Partnership's equity income from Great Lakes in 2011 (2010 – $69.3 million; 2009 – $66.1 million). At December 31, 2011, $7.1 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2010 – $11.0 million).

Please read Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more 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, credit, liquidity and foreign exchange risks. 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 were structured such that the cash flows matched those of the Senior Credit Facility. There were no amounts hedged at December 31, 2011 (2010 – $375.0 million). $300.0 million of variable-rate debt was hedged by an interest rate swap through December 12, 2011, where the fixed interest rate paid was 4.89 percent. $75.0 million of variable-rate debt was hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid was 3.86 percent. In addition to these fixed rates, the Partnership paid 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, 2011, the fair value of the interest rate swaps accounted for as hedges was nil (2010 – $13.8 million current liability). In 2011, the Partnership recorded interest expense of $13.6 million on the interest rate swaps and options (2010 – $16.5 million; 2009 – $15.1 million).

At December 31, 2011, we had $363.0 million (2010 – $483.0 million) outstanding on our Senior Credit Facility. If LIBOR interest rates hypothetically increased by one percent (100 basis points) compared to the rates in effect at December 31, 2011, our annual interest expense would increase and our net income would decrease by $3.6 million; and if LIBOR interest rates hypothetically decreased by one percent compared to the rates in effect at December 31, 2011, our annual interest expense would decrease and our net income would increase by $3.6 million. These amounts have been determined by considering the impact of hypothetical interest rates on unhedged debt outstanding as of December 31, 2011.

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 of December 31, 2011, 74 percent of Northern Border's outstanding debt was at fixed rates (2010 – 65 percent).

If interest rates hypothetically increased by one percent (100 basis points) compared with rates in effect at December 31, 2011, Northern Border's annual interest expense would increase and its net income would decrease by approximately $1.2 million; and if interest rates hypothetically decreased by one percent compared with rates in effect at December 31, 2011, Northern Border's annual interest expense would decrease and its net income would increase by approximately $1.2 million.

Great Lakes, GTN 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 Bison and North Baja, as they currently do 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, 2011, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $7.6 million (2010 – $7.6 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 lingering effects of the deterioration of global financial markets in the past few years, 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, 2011, the Partnership had a committed revolving bank line of $500.0 million maturing in 2016. As of December 31, 2011, the outstanding balance on this facility was $363.0 million. In addition, at December 31, 2011, Northern Border had a committed revolving bank line of $200.0 million maturing in 2016. As of December 31, 2011, $123.0 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 quarter ended December 31, 2011, 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 of December 31, 2011 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 (KPMG), 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-1 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	55	Chairman and Director
Steven D. Becker	61	President, Principal Executive Officer and Director
Jack F. Jenkins-Stark	61	Independent Director
Malyn K. Malquist	59	Independent Director
Walentin (Val) Mirosh	66	Independent Director
James M. Baggs	50	Director
Kristine L. Delkus	54	Director
Stuart P. Kampel	43	Vice-President and General Manager
Sandra P. Ryan-Robinson	48	Controller, Principal Financial Officer
Terry C. Ofremchuk	61	Vice-President, Taxation
Rhonda L. Amundson	50	Treasurer
Donald J. DeGrandis	63	Secretary
Annie C. Belecki	40	Assistant Secretary

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 strategy.

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, 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 and our Audit Committee. 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. Malquist was appointed a director of the General Partner in April 2011. Mr. Malquist is an executive with more than 30 years' experience serving in a variety of business, operations and financial roles. Mr. Malquist currently serves on the Board of Directors of Headwaters Incorporated, an NYSE-listed company that develops and commercializes technologies that enhance the value of coal, gas, oil and other natural resources. From May 2006 to March 2009, Mr. Malquist served as Executive Vice-President of Avista Corporation (Avista), (energy production, transmission and distribution company). He also served as Chief Financial Officer of Avista from November 2002 to September 2008, Treasurer from February 2004 to January 2006 and Senior Vice-President from September 2002 to May 2006. Prior to his employment at Avista, Mr. Malquist held various positions at Sierra Pacific Resources, (electricity provider), including President, Chief Executive Officer and Chief Operating Officer from January 1998 to April 2000 and various Senior Vice-President positions from 1994 to 1998. Through his extensive prior management experience, including serving as chief financial officer and chief executive officer of various energy companies, Mr. Malquist brings extensive knowledge regarding financial operations, energy risk management and knowledge of the energy industry to the Board of Directors and the Audit Committee. 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. In addition, Mr. Malquist's experience in the energy industry is beneficial to the service he provides to the Board of the Partnership.

Mr. Mirosh was appointed a director of the General Partner in September 2004. Mr. Mirosh's principal occupation is President of Mircan Resources Ltd., (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 (energy services, specialty chemicals and construction products distribution) and Murphy Oil Corporation (an international oil and gas company). 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. Moreover, Mr. Mirosh's experience and industry knowledge, complemented by an engineering and legal educational background, enable Mr. Mirosh to provide the Board of Directors and Audit Committee 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 23 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 July 2011, Mr. Kampel was appointed Vice-President and General Manager for the General Partner. This is Mr. Kampel's principal occupation. Previously he was Vice-President, Business Development for the General Partner. Mr. Kampel is also Director, Pipeline 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 and the United States.

Ms. Ryan-Robinson was appointed principal financial officer of the General Partner and Controller of the General Partner in September 2011. Her principal occupation is Director of Pipeline Accounting for TransCanada. From April 2007 to April 2011, Ms. Ryan-Robinson was Manager, Accounting Research & Projects for TransCanada and from August 2003 to April 2007, she was Project Manager, Regulatory Services for TransCanada.

Mr. Ofremchuk was appointed Vice-President, Taxation of the General Partner in July 2007. Mr. Ofremchuk's principal occupation is Director, Taxation of TransCanada, a position he has held since December 2011. Prior to this position Mr. Ofremchuk was a Manager, Corporate Taxation of TransCanada, a position he held since October 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 Vice-President and Corporate Secretary of TransCanada, a position he has held since June 2006.

Ms. Belecki was appointed Assistant Secretary of the General Partner in July 2009. Ms. Belecki's principal occupation is Senior Legal Counsel, Corporate and Securities of TransCanada, a position she has held since September 2006.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the General Partner has determined that Malyn Malquist and Jack Jenkins-Stark are "audit committee financial experts," are "independent" and are "financially sophisticated" as defined under applicable SEC and NYSE Corporate Governance rules. The board's affirmative determination for both Malyn Malquist 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 Malyn Malquist, 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 NYSE. 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 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 2011.

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 to 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 President 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 2011, 2010 and 2009 for our President and Principal Executive Officer, our current and former Principal Financial Officer and other executive officers of our General Partner for whom salaries and benefits of more than $100,000 were allocated to us.

Summary Compensation Table

		Compensation Allocated to the Partnership			
Name and Principal Position	Year	Base Salary	Benefits[a][b]	Incentive Compensation[a][c]	Total Compensation
Steven D. Becker	**2011**	**103,905**	**27,015**	**54,031**	**184,951**
President and Principal Executive Officer	2010	29,424	8,827	14,418	52,669
	2009	–	–	–	–
Sandra P. Ryan-Robinson[d]	**2011**	**21,662**	**5,632**	**11,264**	**38,559**
Controller and Principal Financial Officer	2010	–	–	–	–
	2009	–	–	–	–
Robert C. Jacobucci[e]	**2011**	**48,540**	**12,620**	**25,241**	**86,401**
Former Controller and Principal Financial Officer	2010	27,054	8,116	13,256	48,427
	2009	3,450	1,104	1,656	6,209
Stuart P. Kampel	**2011**	**95,752**	**24,895**	**49,791**	**170,438**
Vice-President and General Manager	2010	9,217	2,765	4,516	16,498
	2009	–	–	–	–
Terry C. Ofremchuk	**2011**	**81,012**	**21,063**	**42,126**	**144,202**
Vice-President, Taxation	2010	80,805	24,242	39,594	144,641
	2009	74,827	23,945	35,917	134,689
Rhonda Amundson	**2011**	**66,210**	**17,214**	**34,429**	**117,853**
Treasurer	2010	67,336	20,201	32,995	120,532
	2009	62,203	19,905	29,857	111,965

[a] We reimburse our General Partner for benefit and incentive compensation expenses based on a set formula. These expenses include 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 TransCanada's employee savings plan, and premiums for health and life insurance.

(b) The benefits reimbursement is determined monthly and calculated based on total monthly base salary allocated to us multiplied by a factor of 0.26 for benefits in 2011 (2010 – factor of 0.30; 2009 – factor of 0.32).

(c) The incentive compensation reimbursement is determined monthly and calculated based on total monthly salary allocated to us multiplied by a factor of 0.52 for incentive compensation in 2011 (2010 – factor of 0.49; 2009 – factor of 0.48).

(d) 2011 figures for Ms. Ryan-Robinson relate to the period from September 2011 to December 2011.

(e) 2011 figures for Mr. Jacobucci relate to the period from January 2011 to August 2011.

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
James M. Baggs
Kristine L. Delkus
Jack F. Jenkins-Stark
Gregory A. Lohnes
Malyn K. Malquist
Walentin (Val) Mirosh

Independent Director Compensation

Independent Director Compensation[a] For the year ended December 31, 2011 *(in dollars)*	Earned or Paid in Cash[b]	Unit Awards[c]	All Other Compensation[d]	Total
Malyn K. Malquist[e]	45,000	–	152	45,152
Jack F. Jenkins-Stark[f]	75,500	32,000	17,518	125,018
Walentin (Val) Mirosh	65,000	32,000	9,082	106,082
David L. Marshall[g]	53,500	32,000	7,638	93,138

(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 Gregory A. Lohnes, Steven D. Becker, Kristine L. Delkus and James M. Baggs. 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 25 percent of his fees ($19,875) in Deferred Share Units (DSUs). Due to this election, 415 DSUs were credited to Mr. Jenkins-Stark's account in 2011, all of which were outstanding at December 31, 2011. Malyn K. Malquist elected to receive 50 percent of his fees ($10,000) in DSUs. Due to this election, 235 DSUs were credited to Mr. Malquist's account in 2011, all of which were outstanding at December 31, 2011.

(c) Amounts presented reflect the compensation expense recognized related to the DSUs granted during 2011 under the Deferred Share Unit Plan for Non-Employee Directors. On January 18, 2011, each independent director, other than Mr. Malyn Malquist who had not yet been appointed, was granted 601 DSUs. All of the DSUs granted to Mr. Jenkins-Stark and Mr. Walentine (Val) Mirosh were outstanding at December 31, 2011; Mr. Marshall's units were redeemed on September 1, 2011 following his June 30, 2011 retirement.

At December 31, 2011, Jack F. Jenkins-Stark, Malyn K. Malquist and Walentin (Val) Mirosh held 7,602, 240 and 3,831 DSUs, respectively. The fair value of DSUs held by Mr. Jenkins-Stark, Mr. Malquist and Mr. Mirosh at December 31, 2011 was $288,876, $9,120 and $145,578, respectively.

(d) Amounts presented reflect DSUs credited to each independent director's account equal to the distributions payable on the DSUs previously granted or credited. In this regard, David L. Marshall was credited 176 DSUs, Walentin (Val) Mirosh was credited 239 DSUs, Jack F.

Jenkins-Stark was credited 461 DSUs and Malyn K. Malquist was credited 4 DSUs. All DSUs credited during 2011 were outstanding at December 31, 2011, with the exception of Mr. Marshall's DSUs which were all redeemed on September 1, 2011 as a result of his retirement on June 30, 2011.

(e) Appointed as director on April 18, 2011 and Chairman of the Audit Committee commencing on July 1, 2011.

(f) Lead Director and Chairman of the Conflicts Committee.

(g) Chairman of the Audit Committee until retirement on June 30, 2011.

Cash Compensation

In 2011, each director who was not an employee of TransCanada, the General Partner or its affiliates (independent director) was entitled to a directors' retainer fee of $64,000 per annum, of which $32,000 was automatically granted in DSUs (see DSUs section below). The independent director appointed as Lead Director and chair of the Conflicts Committee and the independent director appointed as chair of the Audit Committee were each entitled to an additional fee of $8,000 per annum. Each independent director was 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 DSUs pursuant to The TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2007). On October 19, 2011, the board approved an increase in the independent directors' 2012 annual retainer fee of $15,000 per annum, of which $10,000 will be granted in DSUs. As a result, commencing January 1, 2012, the retainer fee will be $79,000 per annum, of which $42,000 will automatically be granted in DSUs.

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 2011, as part of the retainer fee, each independent director received an annual grant of DSUs with a value of $32,000.

At the time of grant, the value of a DSU 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 DSU when redeemed is equivalent to the market value of a common unit at the time the redemption takes place. DSUs cannot be redeemed until the director ceases to be a member of the Board. Directors may redeem DSUs for cash or common units at their option. DSUs 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 information as of February 22, 2012 regarding the (i) beneficial ownership of our common units and shares of TransCanada by the General Partner's directors, the named executive officers and directors and executive officers as a group and (ii) beneficial ownership of our common units by all persons known by the General Partner to own beneficially at least 5 percent of our common units.

	Amount and Nature of Beneficial Ownership			
	TC PipeLines, LP		TransCanada Corporation	
Name and Business Address	Number of Common Units[(a)]	Percent of Class[(b)]	Common Shares	Percent of Class
TransCan Northern Ltd.[(c)] 450 1st Street SW Calgary, Alberta T2P 5H1	11,287,725	21.1	–	–
TC Pipelines GP, Inc.[(d)] 450 1st Street SW Calgary, Alberta T2P 5H1	5,797,106	10.8	–	–
Tortoise Capital Advisors, L.L.C.[(e)] 11550 Ash Street, Suite 300 Leawood, Kansas 66211	3,088,553	5.8	–	–
Malyn K. Malquist[(f)]	2,669	*	–	–
Walentin (Val) Mirosh[(g)]	4,811	*	720	*
Jack F. Jenkins-Stark[(h)]	13,533	*	–	–
Gregory A. Lohnes[(i)]	–	–	246,950	*
Steven D. Becker[(j)]	–	–	73,901	*
Kristine L. Delkus[(k)]	–	–	84,500	*
James M. Baggs[(l)]	–	–	64,777	*
Robert C. Jacobucci[(m)]	–	–	651	*
Sandra P. Ryan-Robinson[(n)]			197	*
Directors and Executive officers as a Group[(o)] (14 people)	21,013	*	497,834	*

(a) A total of 53,472,766 common units are issued and outstanding. For certain beneficial owners, the number of common units includes deferred share units, which are a bookkeeping entry, equivalent to the value of a Partnership common unit, and do not entitle the holder to voting or other unitholder rights, other than the accrual of additional deferred share units for the value of distributions. 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 common units.

(b) 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.

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

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

(e) Based on a Schedule 13G/A filed with the SEC on February 10, 2012 by Tortoise Capital Advisors, L.L.C. (Tortoise). In the Schedule 13G/A, Tortoise reported that it has shared power to vote 3,031,783 common units and shared power to dispose of all 3,088,553 common units.

[f] Includes 1,669 deferred share units.

[g] Includes 4,811 deferred share units.

[h] Includes 8,645 deferred share units and 4,888 common units held by the Jenkins-Stark Family Trust dated June 16, 1995.

[i] Includes 226,806 options exercisable within 60 days for TransCanada common shares and 5,490 TransCanada common shares owned by his spouse, of which he disclaims beneficial ownership.

[j] Includes 51,900 options exercisable within 60 days for TransCanada common shares and 4,498 TransCanada common shares held in his Employee Savings Plan account.

[k] Includes 78,376 options exercisable within 60 days for TransCanada common shares and 6,124 TransCanada common shares held in her Employee Savings Plan account.

[l] Includes 59,636 options exercisable within 60 days for TransCanada common shares, 1,808 TransCanada common shares held in his Employee Savings Plan account and 678 TransCanada common shares held in his spouse's Employee Savings Plan account.

[m] Includes 226 TransCanada common shares held in his Employee Savings Plan account and 425 TransCanada common shares held in his spouse's Employee Savings Plan account.

[n] Includes 197 TransCanada common shares held in her Employee Savings Plan account.

[o] Includes 426,905 options exercisable within 60 days for TransCanada common shares, 15,125 deferred share units, 9,016 common shares of TransCanada owned by immediate family members of which beneficial ownership of 6,068 common shares is disclaimed and 29,600 common shares held in the TransCanada Employee Savings Plan.

* Less than one percent.

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

At February 28, 2012, TransCanada owns 11,287,725 common units and the Partnership's General Partner owns 5,797,106 common units, representing an aggregate 31.3 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 33.3 percent by virtue of its indirect ownership of the General Partner and 31.3 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, if applicable, upon 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 of 98 percent 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 percent 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 percent 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 Part II Item 5. "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, 2011 (2010 – $2.2 million; 2009 – $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, GTN and Bison have cash management agreements with TransCanada whereby their funds are pooled with other TransCanada affiliates. The agreements also give these pipeline systems the ability to obtain short-term borrowings to provide liquidity for their operating needs.

Transportation Agreements

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts some of which are provided at discounted rates and some at maximum recourse rates. The contracts have remaining terms ranging from one to six years. Great Lakes earned $80.6 million of transportation revenues under these contracts in 2011 (2010 – $148.5 million; 2009 – $141.7 million). This amount represents 32.2 percent of total revenues earned by Great Lakes in 2011 (2010 – 56.6 percent; 2009 – 48.9 percent).Great Lakes also earned $1.3 million in affiliated rental revenue in 2011 (2010 – $0.9 million; 2009 – $0.6 million).

Revenue from TransCanada and its affiliates of $38.0 million is included in the Partnership's equity income from Great Lakes in 2011 (2010 – $69.3 million; 2009 – $66.1 million). At December 31, 2011, $7.1 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2010 – $11.0 million).

GTN and Bison Acquisitions

On May 3, 2011, we acquired 25 percent membership interests in GTN and Bison from subsidiaries of TransCanada at a purchase price of $605.0 million.

Other Agreements

Our pipeline systems 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.

Capital and operating costs charged to our pipeline systems for the years ended December 31, 2011, 2010 and 2009 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2011 and 2010 are summarized in the following tables:

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Capital and operating costs charged by TransCanada's subsidiaries to:			
Great Lakes	**31.2**	30.3	33.8
Northern Border	**28.7**	25.8	25.5
GTN[(a)]	**22.3**	–	–
Bison[(a)]	**7.7**	–	–
North Baja[(b)]	**3.7**	4.4	2.9
Tuscarora	**4.7**	3.7	3.0
Impact on the Partnership's net income:			
Great Lakes	**14.1**	12.8	14.3
Northern Border	**13.4**	12.5	12.3
GTN[(a)]	**21.2**	–	–
Bison[(a)]	**4.3**	–	–
North Baja[(b)]	**3.5**	3.2	2.4
Tuscarora	**4.6**	3.5	2.8

December 31 *(millions of dollars)*	**2011**	2010
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
Great Lakes	**3.1**	3.0
Northern Border	**2.9**	2.2
GTN[(a)]	**3.0**	–
Bison[(a)]	**1.0**	–
North Baja	**0.5**	0.6
Tuscarora	**0.6**	0.7

(a) Represents operations from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

(b) Recast as discussed in Notes 2 and 5 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 Accountant 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)*	**2011**	2010
Audit Fees[a]	**350.1**	358.8
Tax Fees[b]	**–**	–
All Other Fees	**–**	–
Total	**350.1**	358.8

[a] $75 thousand of the Audit Fees relate to comfort letters and consents issued in conjunction with the financing related to the GTN and Bison Acquisitions, May 3, 2011, and the $350 million Senior Notes issued in July 2011.

[b] The Partnership has not engaged its external auditors for any tax or other services in 2011 or 2010.

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 comfort 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).
*2.3	Agreement for Purchase and Sale of Membership Interest dated as of April 26, 2011 between TransCanada American Investments Ltd., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Exhibit 2.1 to TC PipeLines, LP’s Form 8-K filed on April 27, 2011)
*2.4	Agreement for Purchase and Sale of Membership Interest dated as of April 26, 2011 between TC Continental Pipeline Holdings Inc., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Exhibit 2.2 to TC PipeLines, LP’s Form 8-K filed on April 27, 2011).
*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).
*4.1	Indenture, dated as of June 17, 2011, between the Partnership and The Bank of New York Mellon, as trustee (Exhibit 4.1 to TC PipeLines, LP’s Form 8-K filed on June 17, 2011).
*4.2	Supplemental Indenture, dated as of June 17, 2011 relating to the issuance of $350,000,000 aggregate principal amount of 4.65% Senior Notes due 2021 (Exhibit 4.2 to TC PipeLines, LP’s Form 8-K filed on June 17, 2011).
*4.3	Specimen of 4.65% Senior Notes due 2021 (included as Exhibit A to the Suppmental Indenture filed as Exhibit 4.2 to TC PipeLines, LP’s Form 8-K filed on June 17, 2011).
*4.4	Form of indenture for senior debt securities (included as Exhibit 4.1 to TC PipeLines, LP’s Form 8-K filed on June 14, 2011).
*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).

No.	Description
*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 (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 19, 2011).
*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).
*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).
*10.5.5	Fifth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2010 (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 27, 2011).
10.5.6	Sixth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated February 13, 2012.

No.	Description
*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 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	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).
*10.11	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)).
*10.12	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).
*#10.13	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).
*10.14	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).
*10.15	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).
*10.16	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).
*10.17	Guaranty by TransCanada Pipeline USA Ltd. dated as of April 26, 2011 with respect to the obligations of TransCanada American Investments Ltd. (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on April 27, 2011).
*10.18	Guaranty by TransCanada Pipeline USA Ltd. dated as of April 26, 2011 with respect to the obligations of TC Continental Pipeline Holdings Inc. (Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on April 27, 2011).
*10.19	364-Day Senior Bridge Loan Agreement, dated as of May 3, 2011, among TC PipeLines, LP, the lenders from time to time party thereto, and SunTrust Bank, as Administrative Agent (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on May 5, 2011).

No.	Description
*10.20	First Amendment to Amended and Restated Revolving Credit and Term Loan Agreement, dated as of July 13, 2011, by and among TC PipeLines, LP, the Lenders, and SunTrust Bank, as administrative agent for the Lenders, including (as Exhibit A thereto) the Second Amended and Restated Revolving Credit and Term Loan Agreement dated as of July 13, 2011. (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 19, 2011).
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).
*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).

No.	Description
*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).
99.11	Transportation Service Agreement FT16128 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011.
99.12	Transportation Service Agreement FT16129 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011.
99.13	Transportation Service Agreement FT16130 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011.
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 28th day of February 2012.

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/ Sandra P. Ryan-Robinson

Sandra P. Ryan-Robinson
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 28, 2012
/s/ Steven D. Becker Steven D. Becker	President and Principal Executive Officer	February 28, 2012
/s/ Sandra P. Ryan-Robinson Sandra P. Ryan-Robinson	Controller and Principal Financial Officer	February 28, 2012
/s/ James M. Baggs James M. Baggs	Director	February 28, 2012
/s/ Kristine L. Delkus Kristine L. Delkus	Director	February 28, 2012
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 28, 2012
/s/ Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	February 28, 2012
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 28, 2012

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, 2011 and 2010, 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, 2011. We also have audited TC PipeLines, LP internal control over financial reporting as of December 31, 2011, 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 Control 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.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, 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, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Houston, Texas
February 28, 2012

TC PIPELINES, LP

CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	**2011**	2010
Assets		
Current Assets		
Cash and cash equivalents	**29.5**	3.6
Accounts receivable and other (Note 15)	**8.8**	8.7
	38.3	12.3
Investments in unconsolidated affiliates (Note 3)	**1,609.5**	1,194.8
Plant, property and equipment (Note 4)	**298.5**	312.6
Goodwill	**130.2**	130.2
Other assets	**5.5**	0.6
	2,082.0	1,650.5
Liabilities and Partners' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**5.0**	7.7
Accrued interest	**1.1**	1.3
Current portion of long-term debt (Note 6)	**3.1**	483.8
Fair value of derivative contracts (Note 14)	**–**	13.8
	9.2	506.6
Long-term debt (Note 6)	**739.4**	30.1
Other liabilities	**0.4**	1.3
	749.0	538.0
Partners' Equity (Note 7)		
Common units	**1,306.7**	1,104.2
General partner	**27.6**	23.5
Accumulated other comprehensive loss	**(1.3)**	(15.2)
	1,333.0	1,112.5
	2,082.0	1,650.5

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)	**2011**	2010	2009[a]
Equity earnings from unconsolidated affiliates[b] (Note 3)	**153.5**	126.0	99.4
Transmission revenues	**70.4**	69.1	67.9
Operating expenses	**(14.6)**	(13.0)	(11.0)
General and administrative	**(8.7)**	(4.4)	(6.2)
Depreciation	**(15.2)**	(15.0)	(14.7)
Financial charges and other (Note 8)	**(28.0)**	(25.6)	(29.3)
Net income	**157.4**	137.1	106.1
Net income allocation (Note 9)			
Common units	**154.3**	134.4	90.6
General partner	**3.1**	2.7	7.2
	157.4	137.1	97.8
Net income per common unit (Note 9)	**$3.02**	$2.91	$2.34
Weighted average common units outstanding *(millions)*	**51.1**	46.2	38.7
Common units outstanding, end of year *(millions)*	**53.5**	46.2	46.2

[a] Recast as discussed in Notes 2 and 5.

[b] Includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net income[a]	**157.4**	137.1	106.1
Other comprehensive income			
Change associated with current period hedging transactions (Note 14)	**13.8**	10.0	7.9
Change associated with current period hedging transactions of investees	**0.1**	0.5	1.3
	13.9	10.5	9.2
Total comprehensive income	**171.3**	147.6	115.3

[a] Recast as discussed in Notes 2 and 5 and includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

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)	**2011**	2010	2009[(a)]
Cash Generated From Operations			
Net income	**157.4**	137.1	106.1
Depreciation	**15.2**	15.0	14.7
Amortization of debt issue costs (Note 8)	**2.0**	0.5	0.4
Equity earnings in excess of cumulative distributions:			
Bison[(b)]	**(1.5)**	–	–
(Decrease)/increase in other long-term liabilities	**(0.9)**	0.6	0.3
Equity allowance for funds used during construction	**–**	(0.3)	(0.5)
(Increase)/decrease in operating working capital (Note 11)	**(3.0)**	3.1	2.5
	169.2	156.0	123.5
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Great Lakes	**13.4**	10.5	13.4
Northern Border	**23.6**	18.7	35.4
GTN[(b)]	**21.1**	–	–
Investment in Great Lakes (Note 3)	**(8.9)**	(9.3)	(0.1)
Investment in Northern Border (Notes 3)	**(54.8)**	–	(42.3)
Acquisition of GTN and Bison (Note 5)	**(538.7)**	–	–
Acquisition of North Baja, net of cash acquired (Note 5)	**–**	–	(271.4)
Capital expenditures	**(3.5)**	(9.3)	(1.9)
Increase in investing working capital (Note 11)	**–**	–	(2.9)
	(547.8)	10.6	(269.8)
Financing Activities			
Distributions paid (Note 10)	**(154.8)**	(138.7)	(117.0)
Equity issuances, net	**337.6**	–	265.6
Long-term debt issued (Note 6)	**894.4**	74.0	208.0
Long-term debt repaid (Note 6)	**(665.8)**	(101.4)	(203.5)
Debt issue costs	**(6.9)**	–	–
Due to North Baja's former parent (Note 6)	**–**	–	(12.1)
	404.5	(166.1)	141.0
Increase/(decrease) in cash and cash equivalents	**25.9**	0.5	(5.3)
Cash and cash equivalents, beginning of year	**3.6**	3.1	8.4
Cash and cash equivalents, end of year	**29.5**	3.6	3.1
Interest payments made	**13.1**	8.5	16.5

(a) Recast as discussed in Notes 2 and 5.

(b) Includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

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	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, 2008	34.9	891.4	19.1	(34.9)	34.9	875.6
Net income[(a)]	–	98.8	7.3	–	–	106.1
Net income attributed to former North Baja owner	–	(8.2)	(0.1)	–	–	(8.3)
Equity issuances, net (Notes 5 and 7)	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 (Note 5)	–	(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 (Note 5)	–	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
Net income[(b)]	–	154.3	3.1	–	–	157.4
Equity issuance, net (Notes 5 and 7)	7.3	330.9	6.7	–	7.3	337.6
Distributions paid	–	(151.7)	(3.1)	–	–	(154.8)
Excess purchase price over net acquired assets (Note 5)	–	(130.9)	(2.7)	–	–	(133.6)
Other comprehensive income	–	–	–	13.9	–	13.9
Partners' equity at December 31, 2011	**53.5**	**1,306.8**	**27.5**	**(1.3)**	**53.5**	**1,333.0**

(a) Recast as discussed in Notes 2 and 5.

(b) Includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

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 (TransCanada Corporation together with its subsidiaries 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 1,407-mile U.S. interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to markets in the Midwestern U.S.;
- a 25 percent interest in Gas Transmission Northwest LLC (GTN), a Delaware limited liability company. GTN owns a 1,353-mile pipeline that transports natural gas from the British Columbia, Canada/Idaho border to a point at the Oregon/California border;
- a 25 percent interest in Bison Pipeline LLC (Bison), a Delaware limited liability company. Bison owns a 303-mile pipeline that transports natural gas from the Powder River Basin in Wyoming to Northern Border's pipeline system in North Dakota;
- 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 (EPNG) pipeline near Ehrenberg, Arizona and an interconnection near Ogilby, California on the California/Mexico border with the Gasoducto Rosarito 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 GTN, to a terminus in Northern Nevada.

The Partnership is managed by its General Partner, TC PipeLines GP, Inc. (General Partner), an indirect 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, together with its general partner interest, representing an effective 12.6 percent interest in the Partnership at December 31, 2011. TransCanada also indirectly holds an additional 11,287,725 common units representing a 20.7 percent limited partner interest in the Partnership for a total interest in the Partnership of 33.3 percent at December 31, 2011.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The accompanying financial statements and related notes present the financial position of the Partnership as of December 31, 2011 and 2010 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2011, 2010 and 2009. The Partnership uses the equity method of accounting for its investments in Great Lakes, Northern Border, GTN and Bison, over which it is able to exercise significant influence. The Partnership consolidates its investments in North Baja and Tuscarora.

Amounts are stated in U.S. dollars.

(b) Acquisitions

On May 3, 2011, the Partnership acquired a 25 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada (Acquisitions). The Acquisitions were accounted for as transactions between entities under common control, whereby the equity investments in GTN and Bison were recorded at TransCanada's carrying values. See Note 5 for additional disclosure regarding the Acquisitions.

On July 1, 2009, the Partnership acquired a 100 percent interest in North Baja from a subsidiary of TransCanada. The acquisition was accounted for as a transaction between entities under common control 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 5 for additional disclosure regarding the North Baja acquisition.

(c) 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 of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from 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.

(d) 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.

(e) Plant, Property and Equipment

Plant, property and equipment of North Baja and Tuscarora are 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 20 to 30 years. Metering and other is depreciated on a straight-line basis over the estimated useful lives of the equipment, which range from 5 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.

(f) Long-lived Assets

Long-lived assets, such as property, plant, and equipment, and purchased intangible assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, we first compare undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals, as considered necessary.

(g) Partners' Equity

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

(h) 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 of December 31, 2011, 2010 and 2009, the Partnership has not recognized any transmission revenue that is subject to possible refund.

(i) 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.

(j) 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, 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.

(k) Derivative Financial Instruments and Hedging Activities

The Partnership recognizes all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

The Partnership only enters into derivative contracts that it intends to designate as a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For all hedging relationships, the Partnership formally documents the hedging relationship and its risk management objective and strategy for undertaking the hedge, the hedging instrument, the hedged transaction, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. The Partnership also formally assesses, both at the inception of the hedging relationship and on an ongoing basis, whether the derivatives that are used in hedging relationships are highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that are designated and qualify as part of a cash flow hedging relationship, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

The Partnership discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting cash flows attributable to the hedged risk, the derivative expires or is sold, terminated, or exercised, the cash flow hedge is de-designated because a forecasted transaction is not probable of occurring, or management determines to remove the designation of the cash flow hedge.

In all situations in which hedge accounting is discontinued and the derivative remains outstanding, the Partnership continues to carry the derivative at its fair value on the balance sheet and recognizes any subsequent changes in its fair value in earnings. When it is probable that a forecasted transaction will not occur, the Partnership discontinues hedge accounting and recognizes immediately in earnings gains and losses that were accumulated in other comprehensive income related to the hedging relationship.

(l) Asset Retirement Obligation

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

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. Asset retirement obligations exist for certain of our transmission assets; however, the fair value of the obligations cannot be determined due to the inability to determine the scope of asset retirements, as well as the end of the transmission system life is not determinable with the degree of accuracy necessary to currently establish a liability for the obligation.

We are required to operate and maintain our natural gas pipeline systems, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe our natural gas pipeline system assets have indeterminate lives and, accordingly, have recorded no asset retirement liabilities as of December 31, 2011 and 2010. We continue to evaluate our asset retirement obligations and future developments that could impact amounts in our records.

(m) 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 of December 31, 2011, Tuscarora has no regulatory assets (2010 – nil) and $0.2 million in regulatory liabilities (2010 – $0.5 million). North Baja has no regulatory assets or liabilities as of December 31, 2011 and 2010. Allowance for funds used during construction is capitalized and included in plant, property and equipment.

(n) 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 INVESTMENTS IN UNCONSOLIDATED AFFILIATES

Great Lakes, Northern Border, GTN and Bison are regulated by the FERC and are operated by TransCanada. We use the equity method of accounting for our interests in our equity investees.

(unaudited) (millions of dollars)	Ownership Interest at December 31, 2011	Equity Earnings from Unconsolidated Affiliates Year Ended December 31			Investment in Unconsolidated Affiliates December 31	
		2011	2010	2009	**2011**	2010
Great Lakes	46.45%	**59.5**	58.7	59.1	**685.5**	690.0
Northern Border[(a)]	50%	**75.5**	67.3	40.3	**536.1**	504.8
GTN[(b)]	25%	**11.5**	–	–	**225.1**	–
Bison[(b)]	25%	**7.0**	–	–	**162.8**	–
		153.5	126.0	99.4	**1,609.5**	1,194.8

(a) Equity income from Northern Border is net of the 12-year amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the Partnership's additional 20 percent acquisition in April 2006.

(b) Represents equity earnings from May 3, 2011, date of acquisition, to December 31, 2011.

Great Lakes

The Partnership owns a 46.45 percent general partner interest in Great Lakes. TransCanada owns the other 53.55 percent partnership interest. 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.

Rates on the Great Lakes Pipeline are based on a July 2010 FERC approved settlement which became effective May 1, 2010 and applies to all current and future shippers on Great Lakes.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2011, 2010, and 2009.

At December 31, 2011 the partnership had a $458.4 million (2010 – $458.4 million) difference between the carrying value of Great Lakes and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in the Partnership's investment in Great Lakes relating to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes.

The Partnership made equity contributions to Great Lakes of $4.2 million and $4.6 million in the first quarter and fourth quarter of 2011, respectively. These amounts represent the Partnership's 46.45 percent share of a $9.0 million and $10.0 million cash call from Great Lakes to make scheduled debt repayments.

The summarized financial information for Great Lakes is as follows:

December 31 (millions of dollars)	**2011**	2010
Assets		
Current assets	**65.3**	83.7
Plant, property and equipment, net	**826.2**	846.9
Other assets	**0.6**	0.6
	892.1	931.2
Liabilities and Partners' Equity		
Current liabilities	**30.0**	34.9
Deferred credits	**0.4**	5.6
Long-term debt, including current maturities	**373.0**	392.0
Partners' capital	**488.7**	498.7
	892.1	931.2

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Transmission revenues	**250.0**	262.4	289.7
Operating expenses	**(61.8)**	(59.2)	(66.5)
Depreciation	**(32.2)**	(40.5)	(58.5)
Financial charges and other	**(29.9)**	(30.9)	(31.9)
Michigan business tax	**1.9**	(5.3)	(5.4)
Net income	**128.0**	126.5	127.4

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.

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 recorded no undistributed earnings from Northern Border for the years ended December 31, 2011, 2010 and 2009.

At December 31, 2011, the Partnership had a $119.9 million (2010 – $120.8 million) difference between the carrying value of Northern Border and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in 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.

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, the Partnership made the required equity contributions of $49.8 million in the third quarter of 2011 and $5 million in the fourth quarter of 2011 to meet minimum equity to total capitalization requirements and to fund capital expenditures related to the Princeton Lateral Project respectively.

The summarized financial information for Northern Border is as follows:

December 31 (millions of dollars)	**2011**	2010
Assets		
Cash and cash equivalents	**32.8**	10.2
Other current assets	**35.6**	37.1
Plant, property and equipment, net	**1,266.6**	1,294.8
Other assets	**31.4**	22.9
	1,366.4	1,365.0
Liabilities and Partners' Equity		
Current liabilities	**48.6**	46.7
Deferred credits and other	**12.8**	9.7
Long-term debt, including current maturities	**472.6**	540.6
Partners' equity		
Partners' capital	**835.1**	770.9
Accumulated other comprehensive loss	**(2.7)**	(2.9)
	1,366.4	1,365.0

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Transmission revenues	**310.1**	295.1	249.2
Operating expenses	**(73.2)**	(74.0)	(70.8)
Depreciation	**(61.6)**	(61.5)	(61.9)
Financial charges and other	**(22.6)**	(23.4)	(34.4)
Net income	**152.7**	136.2	82.1

GTN

On May 3, 2011, the Partnership acquired a 25 percent membership interest in GTN from a subsidiary of TransCanada. The acquisition was accounted for as a transaction between entities under common control, whereby the equity investment in GTN was recorded at TransCanada's carrying value. See Note 5 for additional disclosure regarding the Acquisitions.

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

On August 12, 2011, GTN filed a petition with the FERC requesting approval of a Stipulation and Agreement of Settlement (GTN Settlement) with shippers and regulators regarding GTN's rates and terms and conditions of service. In November 2011, the FERC approved the GTN Settlement without modification, effective January 1, 2012. The GTN Settlement includes a moratorium on the filing of future rate proceedings until December 31, 2015. Following the expiration of the moratorium, GTN must file a rate case such that the new rates will be effective January 1, 2016. GTN's new rates were determined in a settlement reflecting GTN's rate base, revenue requirement and contract levels.

The Partnership recorded no undistributed earnings from GTN for the year ended December 31, 2011.

The summarized financial information for GTN from May 3, 2011, date of acquisition, to December 31, 2011 is as follows:

December 31 (millions of dollars)	**2011**
Assets	
Current assets	**54.6**
Plant, property and equipment, net	**1,207.2**
Other assets	**1.1**
	1,262.9
Liabilities and Members' Equity	
Current liabilities	**17.7**
Deferred credits and other	**19.7**
Long-term debt, including current maturities	**325.0**
Members' capital	**900.5**
	1,262.9

For the period May 3 to December 31, 2011 (millions of dollars)	
Transmission revenues	**133.2**
Operating expenses	**(36.7)**
Depreciation	**(36.2)**
Financial charges and other	**(15.0)**
Net income	**45.3**

Bison

On May 3, 2011, the Partnership acquired a 25 percent membership interest in Bison from a subsidiary of TransCanada. The acquisition was accounted for as a transaction between entities under common control, whereby the equity investment in Bison was recorded at TransCanada's carrying value. See Note 5 for additional disclosure regarding the Acquisitions.

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

The Partnership recorded undistributed earnings from Bison of $1.5 million, from May 3, 2011, date of acquisition, to December 31, 2011.

The summarized financial information for Bison from May 3, 2011, date of acquisition, to December 31, 2011, is as follows:

December 31 (millions of dollars)	**2011**
Assets	
Current assets	**9.9**
Plant, property and equipment, net	**657.9**
Other assets	**–**
	667.8
Liabilities and Members' Equity	
Current liabilities	**16.8**
Members' capital	**651.0**
	667.8

For the period May 3 to December 31, 2011 (millions of dollars)	
Transmission revenues	**51.8**
Operating expenses	**(11.3)**
Depreciation	**(12.4)**
Net income	**28.1**

NOTE 4 PLANT, PROPERTY AND EQUIPMENT

The following table includes plant, property and equipment from North Baja and Tuscarora.

	2011			2010		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**290.0**	**110.0**	**180.0**	290.1	100.6	189.5
Compression	**104.8**	**19.5**	**85.3**	113.4	24.5	88.9
Metering and other	**42.4**	**9.3**	**33.1**	42.2	8.2	34.0
Under construction	**0.1**	**–**	**0.1**	0.2	–	0.2
	437.3	**138.8**	**298.5**	445.9	133.3	312.6

NOTE 5 ACQUISITIONS AND REVISED INCENTIVE DISTRIBUTION RIGHTS

GTN and Bison Equity Investment Acquisitions

On May 3, 2011, the Partnership acquired 25 percent membership interests in GTN and Bison from subsidiaries of TransCanada.

The GTN pipeline system extends from an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border. The Bison pipeline system extends from the Powder River Basin near Gillette, Wyoming to Northern Border's pipeline system in Morton County, North Dakota. GTN and Bison are both Delaware limited liability companies regulated by the FERC, and they are operated by subsidiaries of TransCanada.

The total purchase price of the Acquisitions was $605.0 million (the Purchase Price). The Purchase Price consisted of (i) $405.0 million for the GTN membership interest (less $81.3 million, which reflected 25 percent of GTN's outstanding debt at the time of the acquisition), (ii) $200.0 million for the membership interest in Bison (less a $9.1 million future capital commitment to complete the Bison pipeline) (iii) $23.5 million at closing and (iv) $0.6M in working capital adjustments paid in the fourth quarter of 2011. The resulting $538.7 million paid by the Partnership was financed through a combination of (i) an issuance of 7,245,000 common units offered to the public at $47.58 per common unit resulting in net proceeds of $330.9 million, (ii) a draw of $61.0 million on the Partnership's committed $400.0 million bridge loan facility, (iii) a draw of $125.0 million on the Partnership's then existing $250.0 million senior revolving credit facility, (iv) a capital contribution from the General Partner of $6.7 million, which was required to maintain the General Partner's effective two percent general partner interest in the Partnership, and (v) approximately $15.1 million of cash on hand.

The Acquisitions were accounted for as transactions between entities under common control, whereby the equity investments in both GTN and Bison were recorded at TransCanada's carrying values of $246.2 million and $161.3 million, respectively. As the fair market value paid for the membership interests in GTN and Bison was greater than the recorded equity investments in GTN and Bison, the total excess purchase price paid of $131.2 million was recorded as a reduction to Partners' Equity.

Yuma Lateral Asset Acquisition

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, the Partnership paid $2.4 million to TransCanada on March 25, 2011 when the facilities associated with the additional contracts were completed.

The Yuma Lateral asset purchase was accounted for as a transaction between entities under common control whereby the assets acquired were recorded at TransCanada's carrying value. As the fair value paid for the Yuma Lateral assets of $10.0 million was greater than the $7.7 million recorded as plant, property and equipment, the excess of $2.3 million was recorded as a decrease to Partners' Equity at December 31, 2011.

North Baja Acquisition

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 Rosarito 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 then existing $250.0 million senior revolving credit facility (ii) issuance of 2,609,680 common units at $30.042 per common unit to TransCanada for net 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 effective 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 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 allocated 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 for the year ended December 31, 2009 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.

NOTE 6 CREDIT FACILITIES AND LONG-TERM DEBT

December 31 (millions of dollars)	**2011**	2010
Senior Credit Facility due 2016	**363.0**	483.0
4.65% Senior Notes due 2021	**349.4**	–
6.89% Series C Senior Notes due 2012	**3.1**	3.9
3.82% Series D Senior Notes due 2017	**27.0**	27.0
	742.5	513.9
Less: current portion of long-term debt	**3.1**	483.8
	739.4	30.1

The Partnership's Senior Credit Facility consists of a $500.0 million senior revolving credit facility with a banking syndicate, maturing July 13, 2016, under which $363.0 million was outstanding at December 31, 2011 (2010 – $8.0 million), leaving $137.0 million available for future borrowing. At December 31, 2010 the senior credit facility also included a $475.0 million senior term loan of which $175.0 million was repaid on June 17, 2011 and the remaining $300.0 million was repaid on December 12, 2011.

On July 13, 2011, the Partnership closed an amendment to its Senior Credit Facility increasing the senior revolving credit facility from $250.0 million to $500.0 million, and extending the maturity date of the senior revolving credit facility to July 2016 from December 2011. At the Partnership's option, the interest rate on the outstanding borrowings under the senior revolving credit facility may be the lenders' base rate or the London Interbank Offered Rate (LIBOR) plus, in either case, an applicable margin that is based on the Partnership's long-term unsecured credit ratings. The Senior Credit Facility permits the Partnership to specify the portion of the borrowings to be covered by specific interest rate options and, for LIBOR-based borrowings, to specify the interest rate period. The Partnership is required to pay a commitment fee based on its credit rating and on the unused principal amount of the commitments under the senior revolving credit facility. The senior revolving credit facility has a feature whereby at any time, so long as no event of default has occurred and is continuing, the Partnership may request an increase in the senior revolving credit facility of up to $250.0 million, but no lender has an obligation to increase their respective share of the facility.

The interest rate on the Senior Credit Facility averaged 0.86 percent for the year ended December 31, 2011 (2010 – 0.91 percent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.07 percent for the year ended December 31, 2011 (2010 – 4.30 percent). Prior to hedging activities, the interest rate was 1.65 percent at December 31, 2011 (2010 – 0.83 percent).

On June 17, 2011, the Partnership closed a $350.0 million public debt offering of 10-year, senior unsecured notes with an interest rate of 4.65 percent. Proceeds were used to repay funds borrowed under the Partnership's bridge loan facility and to partially repay borrowings under our existing Senior Credit Facility. The senior notes mature June 15, 2021. The indenture for the notes contains customary investment grade covenants.

On May 3, 2011, the Partnership entered into an agreement with SunTrust Robinson Humphrey, Inc., as Arranger, for a 364-day senior unsecured bridge loan facility for up to $400.0 million to fund the GTN and Bison Acquisitions. Borrowings under the bridge loan facility bore interest based, at the Partnership's election, on the lenders' base rate or the LIBOR plus in either case, an applicable margin. On May 3, 2011, the Partnership drew $61.0 million to partially fund the GTN and Bison Acquisitions. Please see Note 5 for more details on the Acquisitions. On June 17, 2011, the Partnership repaid the $61.0 million draw, and the bridge loan facility was cancelled. The interest rate on the loan made under the bridge loan facility was 1.7 percent.

At December 31, 2011, 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 second amended and restated agreement of limited partnership (Partnership Agreement), incurring additional debt and distributions to unitholders.

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)	
2012	3.1
2013	3.5
2014	3.6
2015	3.7
2016	3.9
Thereafter	724.7
	742.5

NOTE 7 PARTNERS' EQUITY

At December 31, 2011, Partners' equity included 53,472,766 common units (2010 – 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 12.6 percent ownership in the Partnership at December 31, 2011 (2010 – 14.3 percent).

On May 3, 2011, the Partnership completed a public offering of 7,245,000 common units at $47.58 per common unit for gross proceeds of $344.7 million and net proceeds of $330.9 after unit issuance costs. The General Partner maintained its effective two percent general partner interest in the Partnership by contributing $6.7 million to the Partnership in connection with the offering. See Note 5 for additional information regarding the equity issuance in connection with the Acquisitions.

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. The General Partner maintained its effective two percent general partner interest in the Partnership by contributing $3.8 million to the Partnership in connection with the offering. See Note 5 for disclosure regarding the equity issuance in connection with the acquisition of North Baja in 2009.

NOTE 8 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Interest expense on long-term debt	**13.9**	8.4	12.5
Interest expense on short-term debt[(a)]	**–**	–	2.1
Capitalized interest[(a)]	**–**	(0.2)	(0.4)
Loss on interest rate swaps and options	**13.6**	16.5	15.1
Interest income[(a)]	**(1.5)**	–	(0.4)
Amortization of debt issue costs	**2.0**	0.5	0.4
Other	**–**	0.4	–
	28.0	25.6	29.3

(a) Recast as discussed in Notes 2 and 5.

NOTE 9 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 effective two percent general partner 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)	**2011**	2010	2009
Net income[(a)]	**157.4**	137.1	106.1
North Baja's contribution prior to acquisition	**–**	–	(8.3)
Net income allocated to partners[(b)]	**157.4**	137.1	97.8
Net income allocated to General Partner:			
General partner interest	**(3.1)**	(2.7)	(1.9)
Incentive distribution income allocation	**–**	–	(5.3)
	(3.1)	(2.7)	(7.2)
Net income allocable to common units	**154.3**	134.4	90.6
Weighted average common units outstanding *(millions)*	**51.1**	46.2	38.7
Net income per common unit	**$3.02**	$2.91	$2.34

(a) 2011 net income includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011. 2009 net income was recast as discussed in Notes 2 and 5.

(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 10 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 $0.77 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, 2011, the Partnership distributed $3.04 per common unit (2010 – $2.94 per common unit; 2009 – $2.87 per common unit) for a total of $154.8 million (2010 – $138.7 million; 2009 – $117.0 million). The distributions paid for the year ended December 31, 2011 included no incentive distributions to the General Partner (2010 – $nil; 2009 – $5.3 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 11 CHANGE IN WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2011**	2010	2009[(a)]
(Increase)/decrease in accounts receivable and other	**(0.1)**	(0.1)	2.8
(Decrease)/increase in accounts payable and accrued liabilities	**(2.7)**	3.2	(0.8)
Decrease in accrued interest	**(0.2)**	–	(2.4)
	(3.0)	3.1	(0.4)
Increase in investing working capital	**–**	–	(2.9)
(Increase)/decrease in operating working capital	**(3.0)**	3.1	2.5

(a) Recast as discussed in Notes 2 and 5.

NOTE 12 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, 2011 (2010 – $2.2 million; 2009 – $2.1 million).

As operator, TransCanada's subsidiaries provide capital and operating services to Great Lakes, Northern Border, GTN, Bison, North Baja and Tuscarora (together, "our pipeline systems"). TransCanada's subsidiaries incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, and property and liability insurance costs.

Capital and operating costs charged to our pipeline systems for the years ended December 31, 2011, 2010 and 2009 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2011 and 2010 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Capital and operating costs charged by TransCanada's subsidiaries to:			
Great Lakes	**31.2**	30.3	33.8
Northern Border	**28.7**	25.8	25.5
GTN[(a)]	**22.3**	–	–
Bison[(a)]	**7.7**	–	–
North Baja[(b)]	**3.7**	4.4	2.9
Tuscarora	**4.7**	3.7	3.0
Impact on the Partnership's net income:			
Great Lakes	**14.1**	12.8	14.3
Northern Border	**13.4**	12.5	12.3
GTN[(a)]	**21.2**	–	–
Bison[(a)]	**4.3**	–	–
North Baja[(b)]	**3.5**	3.2	2.4
Tuscarora	**4.6**	3.5	2.8

December 31 (millions of dollars)	**2011**	2010
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
Great Lakes	**3.1**	3.0
Northern Border	**2.9**	2.2
GTN[(a)]	**3.0**	–
Bison[(a)]	**1.0**	–
North Baja	**0.5**	0.6
Tuscarora	**0.6**	0.7

(a) Represents operations from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

(b) Recast as discussed in Notes 2 and 5.

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts, some of which are provided at discounted rates and some at maximum recourse rates. The contracts have remaining terms ranging from one to six years. Great Lakes earned $80.6 million of transportation revenues under these contracts in 2011 (2010 – $148.5 million; 2009 – $141.7 million). This amount represents 32.2 percent of total revenues earned by Great Lakes in 2011 (2010 – 56.6 percent; 2009 – 48.9 percent).Great Lakes also earned $1.3 million in affiliated rental revenue in 2011 (2010 – $0.9 million; 2009 – $0.6 million).

Revenue from TransCanada and its affiliates of $38.0 million is included in the Partnership's equity income from Great Lakes in 2011 (2010 – $69.3 million; 2009 – $66.1 million). At December 31, 2011, $7.1 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2010 – $11.0 million).

NOTE 13 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2011 and 2010:

Quarter ended (millions of dollars except per common unit amounts)	**Mar 31**	**Jun 30**	**Sep 30**	**Dec 31**
2011				
Equity income[(a)]	**38.6**	**37.5**	**40.4**	**37.0**
Transmission revenues	**17.3**	**17.6**	**17.6**	**17.9**
Net income[(a)]	**42.3**	**36.1**	**40.7**	**38.3**
Net income per common unit	**$0.90**	**$0.69**	**$0.75**	**$0.70**
Cash distributions paid	**35.4**	**35.4**	**42.0**	**42.0**
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

(a) Includes equity earnings from GTN and Bison from May 3, 2011, date of acquisition, to December 31, 2011.

NOTE 14 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 bear 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 of December 31, 2011 and 2010 are as follows:

	2011		2010	
December 31 (millions of dollars)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Senior Credit Facility	**363.0**	**363.0**	483.0	483.0
Senior Notes	**349.4**	**367.7**	–	–
Series C Senior Notes	**3.1**	**3.3**	3.9	4.3
Series D Senior Notes	**27.0**	**29.4**	27.0	26.6
	742.5	**763.4**	513.9	513.9

The Partnership's long-term debt results in exposures to changing interest rates. Until December 12, 2011, the Partnership used derivatives to assist in managing its exposure to interest rate risk.

The interest rate swaps and options were structured such that the cash flows matched those of the Senior Credit Facility. There were no amounts hedged at December 31, 2011 (2010 – $375.0 million). $300.0 million of variable-rate debt was hedged by an interest rate swap through December 12, 2011, where the fixed interest rate paid was 4.89 percent. $75.0 million of variable-rate debt was hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid was 3.86 percent. In addition to these fixed rates, the Partnership paid 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, 2011, the fair value of the interest rate swaps accounted for as hedges was nil (2010 – $13.8 million current liability). In 2011, the Partnership recorded interest expense of $13.6 million on the interest rate swaps and options (2010 – $16.5 million; 2009 – $15.1 million).

NOTE 15 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2011**	2010
Accounts receivable	**7.6**	7.6
Inventory	**0.9**	0.7
Prepayments	**0.3**	0.4
	8.8	8.7

NOTE 16 REGULATORY MATTERS

On May 24, 2011, the FERC issued an order initiating an investigation pursuant to Section 5 of the NGA to determine whether Tuscarora's existing rates for jurisdictional services were unjust and unreasonable. The FERC initiated this proceeding following a complaint filed by the Public Utilities Commission of Nevada (PUCN) and Sierra Pacific Power Company d/b/a NV Energy (NV Energy). On December 23, 2011, Tuscarora filed a petition with the FERC requesting approval of a Stipulation and Agreement of Settlement (Tuscarora Settlement), resolving all issues, raised in the Section 5 proceeding. On February 6, 2012, the Administrative Law Judge assigned to the case certified the settlement proposal and made a recommendation that the FERC approve the settlement. The settlement includes three year contract extensions to the term of a number of contracts with Tuscarora's largest customer. If approved, the rates will be effective January 1, 2012, and a moratorium on the filing of future rate proceedings under NGA Sections 4 or 5 will extend until December 31, 2014. Pursuant to the settlement, Tuscarora will have no future obligation to file a Section 4 rate case. A decision from the FERC is pending.

NOTE 17 SUBSEQUENT EVENTS

On January 17, 2012, the board of directors of our General Partner declared the Partnership's fourth quarter 2011 cash distribution in the amount of $0.77 per common unit. The fourth quarter cash distribution, which was paid on February 14, 2012 to unitholders of record as of January 31, 2012, totaled $42.0 million and was paid in the following manner: $41.2 million to common unitholders (including $4.5 million to the General Partner as holder of 5,797,106 common units and $8.7 million to TransCanada as holder of 11,287,725 common units) and $0.8 million to the General Partner in respect of its two percent general partner interest.

Great Lakes declared its fourth quarter 2011 distribution of $23.3 million on January 11, 2012, of which the Partnership received its 46.45 percent share or $10.8 million. The distribution was paid on February 1, 2012.

Northern Border declared and paid its fourth quarter 2011 distribution of $50.0 million on February 1, 2012, of which the Partnership received its 50 percent share or $25.0 million.

GTN declared and paid its fourth quarter 2011 distribution of $21.4 million on February 1, 2012, of which the Partnership received its 25 percent share or $5.4 million.

Bison declared its fourth quarter 2011 distribution of $15.6 million on January 11, 2012, of which the Partnership received its 25 percent share or $3.9 million. The distribution was paid on February 1, 2012.

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 balance sheets of Great Lakes Gas Transmission Limited Partnership (the Partnership) as of December 31, 2011 and 2010, and the related statements of income, partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2011. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 13, 2012

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
BALANCE SHEETS

December 31 (In thousands)	2011	2010
Assets		
Current assets:		
Cash and cash equivalents	$ 47	40
Demand loan receivable from affiliate	36,813	44,924
Accounts receivable:		
Trade	8,610	14,610
Affiliates	7,064	11,286
Materials and supplies	10,626	10,824
Other	2,107	1,990
Total current assets	65,267	83,674
Property, plant, and equipment:		
Property, plant, and equipment	2,069,228	2,064,641
Construction work in progress	3,640	1,875
	2,072,868	2,066,516
Less accumulated depreciation and amortization	(1,246,620)	(1,219,579)
Total property, plant, and equipment, net	826,248	846,937
Other assets	553	638
Total assets	$ 892,068	931,249
Liabilities and partners' capital		
Current liabilities:		
Accounts payable:		
Trade	$ 7,651	11,660
Affiliates	3,131	2,976
Current maturities of long-term debt	19,000	19,000
Partnership income taxes payable	3,238	3,729
Taxes payable (other than income)	7,805	8,194
Accrued interest	8,076	8,384
Other	–	38
Total current liabilities	48,901	53,981
Long-term debt, net of current maturities	354,000	373,000
Other liabilities:		
Deferred partnership income taxes	–	5,169
Other	436	436
Total other liabilities	436	5,605
Partners' capital	488,731	498,663
Total liabilities and partners' capital	$ 892,068	931,249

See accompanying notes to financial statements.

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

Years ended December 31 (In thousands)	**2011**	2010	2009
Operating revenues	**$ 250,006**	262,391	289,693
Operating expenses:			
Operation and maintenance	**44,371**	41,558	48,760
Depreciation and amortization	**32,217**	40,488	58,503
Taxes, other than income	**17,476**	17,694	17,729
Total operating expenses	**94,064**	99,740	124,992
Operating income	**155,942**	162,651	164,701
Other income, net	**–**	238	595
Interest and debt expense	**(29,929)**	(31,339)	(32,916)
Affiliated interest income	**40**	205	449
Income before partnership income taxes	**126,053**	131,755	132,829
Partnership income tax (expense) benefit	**1,915**	(5,290)	(5,417)
Net income	**$ 127,968**	126,465	127,412
Partners' capital:			
Balance at beginning of year	**$ 498,663**	501,298	529,886
Net income	**127,968**	126,465	127,412
Distributions to partners	**(156,900)**	(149,100)	(156,000)
Contributions from partners	**19,000**	20,000	–
Balance at end of year	**$ 488,731**	498,663	501,298

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF CASH FLOWS

Years ended December 31 (In thousands)	**2011**	2010	2009
Cash flows from operating activities:			
Net income	**$ 127,968**	126,465	127,412
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**32,217**	40,488	58,503
Deferred partnership income taxes	**(5,153)**	1,816	1,410
Allowance for funds used during construction, equity	**(84)**	(187)	(78)
Asset and liability changes:			
Accounts receivable	**10,222**	10,006	3,775
Other current assets	**81**	(442)	1,967
Noncurrent assets	**69**	97	24
Accounts payable	**(3,854)**	(3,393)	(4,084)
Partnership income taxes payable	**(491)**	(248)	3,977
Other current liabilities	**(735)**	(1,665)	(2,620)
Noncurrent liabilities	**–**	–	19
Net cash provided by operating activities	**160,240**	172,937	190,305
Cash flows from investing activities:			
Additions to property, plant, and equipment	**(11,444)**	(13,972)	(8,310)
Net change in demand loan receivable from affiliate	**8,111**	(10,950)	(8,507)
Net cash used in investing activities	**(3,333)**	(24,922)	(16,817)
Cash flows from financing activities:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(19,000)
Distributions to partners	**(156,900)**	(149,100)	(156,000)
Contributions from partners	**19,000**	20,000	–
Net cash used in financing activities	**(156,900)**	(148,100)	(175,000)
Net change in cash and cash equivalents	**7**	(85)	(1,512)
Cash and cash equivalents at beginning of year	**40**	125	1,637
Cash and cash equivalents at end of year	**$47**	40	125
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$30,177**	31,582	33,159
Partnership income taxes paid	**2,417**	2,873	–

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO FINANCIAL STATEMENTS
December 31, 2011 and 2010

1. DESCRIPTION OF BUSINESS

Great Lakes Gas Transmission Limited Partnership (the 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, 2011 and 2010 were as follows:

	Ownership percentage
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 33.3% interest following the completion of a common unit offering on May 3, 2011.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Use of Estimates

The preparation of the 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 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 2011 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 (FASB) Accounting Standards Codification (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, 2011 and 2010, there are no significant regulatory assets or liabilities reflected in these financial statements.

(e) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest, except for those receivables subject to late charges. 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 charged to the allowance after all means of collection have been exhausted and the potential for recovery is no longer considered probable. Accounts written off for 2011 and 2010 were not material to the Partnership's 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 balance sheets as trade accounts receivable or accounts receivable from affiliates. Imbalances owed to others are reported on the 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 newly adopted method is preferable. The change resulted in a $1.2 million decrease to operations and maintenance expense in 2010 on the Partnership's 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 under a rate settlement approved by the FERC in July 2010, the substantial portion of the Partnership's principal operating assets are being depreciated at an annual rate of 1.48%. The remaining assets are depreciated at annual rates ranging from 2.33% to 20.00%. Using these rates, the remaining depreciable life of these assets ranges from 4 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. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheets. Capitalized AFUDC debt amounts are included as a reduction of interest and debt expense in the statements of income.

(i) Long-Lived Assets

Long-lived assets, such as property, plant, and equipment, and purchased intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, the Partnership first compares undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals, as considered necessary.

(j) 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 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 allowances for these potential refunds. As of December 31, 2011 and 2010, there are no allowances reflected in these financial statements.

(k) Commitments and Contingencies

Accounting for Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of FASB ASC 410-20, *Asset Retirement Obligations*. FASB ASC 410-20 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. FASB ASC 410-20 also requires the Partnership to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is to be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

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 obligation as of December 31, 2011 and 2010. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

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.

(l) Income Taxes

During the years 2008 through 2011, the State of Michigan imposed a Michigan Business Tax (MBT) on partnerships. Effective for calendar years after 2011, the State of Michigan enacted legislation eliminating this MBT on partnerships and will apply a more conventional income tax system taxing partners of partnerships. In addition, the new tax eliminates the gross receipts tax as well as property and other tax credits. The Partnership recorded a $5.2 million credit to deferred tax expense in 2011 to reflect the Michigan law changes. Income taxes, other than the MBT, are the responsibility of the partners and are not reflected in these 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, 2011, 2010, and 2009 consists of the following:

(In thousands)	**2011**	2010	2009
Current	**$3,238**	3,474	4,007
Deferred	**(5,153)**	1,816	1,410
	$(1,915)	5,290	5,417

The deferred tax liabilities as of December 31, 2011 and 2010 are as follows:

(In thousands)	**2011**	2010
Deferred tax liabilities – utility plant	**$–**	5,041
Deferred tax liabilities – other	**–**	128
Net deferred tax liability	**$–**	5,169

The Partnership's MBT returns are open to audit under the statute of limitations for the 2008 through 2011 tax years. There are no uncertain tax positions related to the Partnership's MBT for the years ended December 31, 2011 and 2010.

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. Based upon the Partnership's evaluation and experience to date, the Partnership had no accruals for its outstanding legal matters at December 31, 2011.

(b) Regulatory Matters

The Partnership is operating under a rate settlement approved by the FERC in July 2010. Under the settlement, the Partnership agreed to a 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 settlement included a moratorium on participants and customers filing any NGA Section 5 rate case to place new rates into effect prior to November 1, 2012. In addition, the Partnership is required 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 Minnesota, Wisconsin, and Michigan as part of the EPA's investigation of the Partnership's compliance with the Clean Air Act. On May 28, 2010, the Partnership submitted its response to the EPA and subsequently responded to a request from the EPA dated July 26, 2010 for information regarding one natural gas compressor station located in Minnesota. On May 31, 2011, the EPA required the Partnership to provide additional information regarding natural gas compressor stations in Minnesota and Michigan. The potential effects on the Partnership that may arise as a result of this information request or the underlying compliance review are not determinable at this time.

(d) Operating Leases

The Partnership has an operating lease for office space in Bemidji, Minnesota. Minimum future annual rental commitments on the Partnership's operating lease as of December 31, 2011 were as follows (in thousands):

Year ending December 31:	
2012	$33
2013	34
2014	36
2015	37
2016	9
Total	$149

(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)	**2011**	2010
8.74% series Senior Notes due 2011	**$–**	10,000
6.73% series Senior Notes due 2012 to 2018	**63,000**	72,000
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
	373,000	392,000
Less current maturities	**19,000**	19,000
Total long-term debt less current maturities	**$354,000**	373,000

The aggregate annual required repayment of long-term debt is $19.0 million for each year from 2012 through 2016. Aggregate required repayments of long-term debt thereafter total $278.0 million.

The Partnership is required to comply with certain financial, operational, and legal covenants. Under the most restrictive covenants in the Senior Note Agreements, approximately $201.0 million of partners' capital was restricted as to distributions as of December 31, 2011. As of December 31, 2011, management of the Partnership believes the Partnership was in compliance with all of its financial covenants.

6. FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under FASB ASC 820, *Fair Value Measurements*, 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.

(b) 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, 2011 and 2010. 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.

	2011		2010	
(In thousands)	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Financial assets:				
Cash and cash equivalents	**$47**	**47**	40	40
Financial liabilities:				
Long-term debt	**$373,000**	**541,245**	392,000	518,199

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 notes, which will result in no gains or losses on its repayment.

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 program are considered loans, accruing interest and repayable on demand. The Partnership receives interest on monies advanced to TransCanada at the rate of interest earned by TransCanada on its short-term cash investments. The Partnership pays interest on monies advanced from TransCanada based on TransCanada's short-term borrowing costs. At December 31, 2011 and 2010, the Partnership had a demand loan receivable from TransCanada of $36.8 million and $44.9 million, respectively.

(b) Affiliate Revenues and Expenses

The Partnership earns transportation revenues from TransCanada and its affiliates under contracts some of which are provided at discounted rates and some at maximum recourse rates. The contracts have remaining terms ranging from one to six years.

The Partnership's largest shipper, TransCanada PipeLines Limited (TCPL), had 576 thousand dekatherms per day (MDth/d) of long haul capacity under contract expire on October 31, 2011. TCPL recontracted 314 MDth/d of this volume for one year through October 31, 2012.

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)	**2011**	2010	2009
Transportation revenues from affiliates	**$80,553**	148,464	141,721
Rental revenue from affiliate	**1,316**	884	643
Costs charged from affiliates	**31,172**	30,282	33,765

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, 2012, the Management Committee of the Partnership declared a cash distribution in the amount of $23.3 million to the partners. The distribution was paid on February 1, 2012.

9. SUBSEQUENT EVENTS

Subsequent events have been assessed through February 13, 2012, which is the date the financial statements were issued, and we 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.

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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 13, 2012

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, (In thousands)	**2011**	2010
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 32,815**	$ 10,231
Accounts receivable	**27,688**	31,129
Related party receivables	**638**	276
Materials and supplies, at cost	**5,138**	4,310
Prepaid expenses and other	**2,182**	1,307
Total current assets	**68,461**	47,253
Property, plant and equipment:		
Natural gas transmission plant	**2,531,592**	2,508,512
Construction work in progress	**940**	8,567
Total property, plant and equipment	**2,532,532**	2,517,079
Less: Accumulated provision for depreciation and amortization	**1,265,894**	1,222,259
Property, plant and equipment, net	**1,266,638**	1,294,820
Other assets:		
Regulatory assets	**28,171**	20,315
Debt issuance costs	**3,131**	2,573
Other	**2**	22
Total other assets	**31,304**	22,910
Total assets	**$1,366,403**	$1,364,983
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 8,319**	$ 10,525
Related party payables	**3,396**	3,015
Accrued taxes other than income	**28,892**	22,976
Accrued interest	**7,123**	7,044
Other	**834**	3,178
Total current liabilities	**48,564**	46,738
Long-term debt, net of current maturities	**472,601**	540,574
Deferred credits and other liabilities:		
Regulatory liabilities	**12,121**	9,649
Other	**705**	–
Total deferred credits and other liabilities	**12,826**	9,649
Commitments and contingencies		
Partners' equity:		
Partners' capital	**835,112**	770,905
Accumulated other comprehensive loss	**(2,700)**	(2,883)
Total partners' equity	**832,412**	768,022
Total liabilities and partners' equity	**$1,366,403**	$1,364,983

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

Years Ended December 31, (In thousands)	**2011**	2010	2009
Operating revenue	**$310,070**	$295,069	$249,217
Operating expenses:			
Operations and maintenance	**50,405**	49,720	48,695
Depreciation and amortization	**61,583**	61,470	61,870
Taxes other than income	**22,824**	24,268	22,103
Operating expenses	**134,812**	135,458	132,668
Operating income	**175,258**	159,611	116,549
Interest expense:			
Interest expense	**26,547**	26,649	36,750
Interest expense capitalized	**(210)**	(60)	(137)
Interest expense, net	**26,337**	26,589	36,613
Other income (expense):			
Allowance for equity funds used during construction	**479**	148	235
Other income	**3,367**	3,165	2,309
Other expense	**(37)**	(86)	(348)
Other income, net	**3,809**	3,227	2,196
Net income to partners	**$152,730**	$136,249	$82,132

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (In thousands)	**2011**	2010	2009
Net income to partners	**$152,730**	$136,249	$82,132
Other comprehensive income:			
Changes associated with hedging transactions	**183**	171	2,654
Total comprehensive income	**$152,913**	$136,420	$84,786

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)	**2011**	2010	2009
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	**$152,730**	$136,249	$82,132
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	**61,615**	61,556	62,218
Allowance for equity funds used during construction	**(479)**	(148)	(235)
Changes in components of working capital	**3,202**	2,034	(25)
South Dakota usage assessment	**(7,401)**	–	–
Other	**(84)**	(519)	(4,084)
Total adjustments	**56,853**	62,923	57,874
Net cash provided by operating activities	**209,583**	199,172	140,006
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	**(29,661)**	(9,861)	(11,090)
Net cash used in investing activities	**(29,661)**	(9,861)	(11,090)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	**109,587**	–	84,550
Distributions to partners	**(198,110)**	(171,944)	(151,458)
Proceeds from issuance of debt	**74,000**	97,000	214,000
Repayment of debt	**(142,000)**	(121,000)	(280,000)
Debt issuance costs	**(815)**	–	(799)
Net cash used in financing activities	**(157,338)**	(195,944)	(133,707)
Net change in cash and cash equivalents	**22,584**	(6,633)	(4,791)
Cash and cash equivalents at beginning of year	**10,231**	16,864	21,655
Cash and cash equivalents at end of year	**$32,815**	$10,231	$16,864
Supplemental disclosure for cash flow information:			
Cash paid for interest, net of amount capitalized	**$25,809**	$26,137	$40,987
Changes in components of working capital:			
Accounts receivable	**$3,441**	$(7,286)	$8,938
Related party receivables	**(362)**	115	(5)
Materials and supplies	**(828)**	161	91
Prepaid expenses and other	**(875)**	265	1,735
Accounts payable	**(2,206)**	7,116	(2,687)
Related party payables	**381**	(375)	(462)
Accrued taxes other than income	**5,916**	263	(3,567)
Accrued interest	**79**	(14)	(4,002)
Other current liabilities	**(2,344)**	1,789	(66)
Total	**$3,202**	$2,034	$(25)

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, 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
Net income to partners	76,365	76,365	–	152,730
Changes associated with hedging transactions	–	–	183	183
Equity contributions received	54,794	54,793	–	109,587
Distributions paid	(99,055)	(99,055)	–	(198,110)
Partners' equity at December 31, 2011	**$417,556**	**$417,556**	**$(2,700)**	**$ 832,412**

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 1,258-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, 2011 and 2010 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

(a) 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.

(b) 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, 2011 and 2010:

	December 31,		Remaining recovery/ settlement
	2011	2010	period
	(In thousands)		*(Years)*
Fort Peck lease option	**$14,097**	$14,457	39
Pipeline extension project	**4,614**	5,075	10
Deferred rate case expenditures	**391**	783	1
Linepack fuel imbalance	**1,668**	–	n/a
South Dakota usage assessment	**7,401**	–	n/a
Total regulatory assets	**$28,171**	$20,315	

At December 31, 2011 and 2010, respectively, we have reflected a regulatory liability of $12.1 million and $9.6 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.

(c) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We maintain 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 we will not collect all or part of the outstanding receivable balance. We regularly review our allowance for doubtful accounts and establish or adjust the allowance as necessary using the specific-identification method. Account balances are charged to the allowance after all means of collection have been exhausted and the potential for recovery is no longer considered probable. Accounts written off for 2011 and 2010 were not material to our financial statements.

(d) 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 provisions for these potential refunds.

(e) Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these financial statements.

(f) Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less.

(g) Materials and Supplies

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

(h) Property, Plant and Equipment and Related Depreciation and Amortization

Property, plant, and equipment are recorded at their original cost of construction. For assets we construct, direct costs are capitalized, such as labor and materials, and indirect costs, such as overhead, interest, and an equity return component on regulated businesses as allowed by the FERC. We capitalize major units of property replacements or improvements and expense minor items.

We use 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 depreciation rates approved in our last rate proceeding. Currently, our depreciation rates vary from 2% to 20% per year. Using these rates, the remaining depreciable life of these assets ranges from 1 to 43 years.

When property, plant, and equipment are retired, we charge 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. We do not recognize a gain or loss unless an entire operating unit is sold or retired. We include gains or losses on dispositions of operating units in income.

We capitalize 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 Company's average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheet.

(i) Long-lived Assets

Long-lived assets, such as property, plant, and equipment, and purchased intangible assets subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If circumstances require a long-lived asset or asset group be tested for possible impairment, we first compare undiscounted cash flows expected to be generated by that asset or asset group to its carrying value. If the carrying value of the long-lived asset or asset group is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. Fair value is determined through various valuation techniques including discounted cash flow models, quoted market values and third-party independent appraisals, as considered necessary.

(j) Asset Retirement Obligation

We account for asset retirement obligations pursuant to the provisions of ASC 410-20, "Asset Retirement Obligations." ASC 410-20 requires us to record the fair value of an asset retirement obligation as a liability in the period in which we incur a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. ASC 410-20 also requires us to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is to be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the 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.

We have determined we have legal obligations associated with our natural gas pipelines and related transmission facilities. The obligations relate primarily to purging and sealing the pipelines if they are abandoned. We are also required to operate and maintain our natural gas pipeline system, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe our natural gas pipeline system assets have indeterminate lives and, accordingly, have recorded no asset retirement liabilities as of December 31, 2011 and 2010. We continue to evaluate our asset retirement obligations and future developments that could impact amounts our records.

(k) 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.

(l) Derivative Instruments and Hedging Activities

We recognize all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivatives designated in hedging relationships, changes in the fair value are either offset through earnings against the change in fair value of the hedged item attributable to the risk being hedged or recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged until the hedged item affects earnings.

We only enter into derivative contracts that we intend to designate as a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For all hedging relationships, we formally document the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the hedged transaction, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. We also formally assess, both at the inception of the hedging relationship and on an ongoing basis, whether the derivatives that are used in hedging relationships are highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that are designated and qualify as part of a cash flow hedging relationship, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

We discontinue hedge accounting prospectively when we determine that the derivative is no longer effective in offsetting cash flows attributable to the hedged risk, the derivative expires or is sold, terminated, or exercised, the cash flow hedge is de-designated because a forecasted transaction is not probable of occurring, or management determines to remove the designation of the cash flow hedge.

In all situations in which hedge accounting is discontinued and the derivative remains outstanding, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings. When it is probable that a forecasted transaction will not occur, we discontinue hedge accounting and recognize immediately in earnings gains and losses that were accumulated in other comprehensive income related to the hedging relationship.

(m) 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.

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

(n) Operating Leases

We have non-cancelable operating leases for office space and rights-of-way. We record rent expense straight-line over the life of the lease.

(o) 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.

(p) 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, 2011, $0.3 million as an other current liability on the accompanying balance sheet for the net over recovery of compressor usage related costs. As of December 31, 2010, we had recorded $2.3 million as an other current liability on the accompanying balance sheet for the net over recovery of compressor usage related costs.

4. MAJOR CUSTOMERS

For the year ended December 31, 2011, shippers providing significant operating revenues were Tenaska Marketing Ventures and BP Canada with revenues of $30.3 million and $29.9 million, respectively. For the year ended December 31, 2010, shippers providing significant operating revenues were Tenaska Marketing Ventures and 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 Energy Marketing Corp. (BP Canada) and Tenaska Marketing Ventures with revenues of $41.9 million and $26.7 million, respectively.

5. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

December 31, (In thousands)	**2011**	2010
2011 Credit Agreement – average interest rate of 1.60% at December 31, 2011 due 2016	**$123,000**	$ –
2007 Credit Agreement – average interest rate of 0.54% at December 31, 2010	**–**	191,000
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	**(399)**	(426)
Long-term debt	**472,601**	540,574

On November 16, 2011, we entered into a $200 million amended and restated revolving credit agreement (2011 Credit Agreement) with certain financial institutions. The 2011 Credit Agreement was used to refinance the outstanding indebtedness under our $250 million revolving credit agreement dated as of April 27, 2007. The 2011 Credit Agreement can also be used to finance permitted acquisitions, pay related fees and expenses, issue letters of credit and provide for ongoing working capital needs and for other general business purposes, including capital expenditures.

At December 31, 2011, based on the principal commitment amount of $200 million, available capacity under the 2011 Credit Agreement was $77 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 2011 Credit Agreement by an aggregate amount not to exceed $300 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 2011 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 commitment fee based our credit rating and on the unused principal amount of the commitment of $200 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 2011 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 consolidated debt to consolidated EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges)) of no more than 5.00 to 1. Pursuant to the 2011 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 two full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2011 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, 2011, we were in compliance with all of our financial covenants.

Aggregate required repayment of long-term debt for the next five years is $223 million in 2016. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2012, 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 had 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	**2011**	2010	2009
	(In thousands)		
Cash flow hedges	**$ –**	$ –	$(3,633)

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	**2011**	2010	2009
		(In thousands)		
Cash flow hedges	Interest expense	**$(183)**	$(171)	$ 979

At December 31, 2011, we have realized losses recorded in accumulated other comprehensive loss of approximately $2.7 million. We expect to reclassify approximately $0.2 million from accumulated other comprehensive loss as an increase to interest expense in 2012.

7. FAIR VALUE MEASUREMENTS

(a) 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.

(b) Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2011 and 2010. 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.

	2011		2010	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	**$32,815**	**$32,815**	$10,231	$10,231
Financial liabilities:				
Long-term debt	**$472,601**	**$541,027**	$540,574	$599,381

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 the "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 2011 Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

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, 2011, 2010, and 2009 were $2.3 million, $1.4 million, and $1.4 million, respectively. Our future minimum lease payments are as follows:

Year ending December 31, (In thousands)	
2012	1,918
2013	1,896
2014	1,889
2015	1,889
2016	2,189
Thereafter	53,216
	$62,997

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 granted 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 lease payments through March 31, 2036. In March 2011, we renewed the pipeline right-of-way lease for a term of 25 years.

Other

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

9. CASH DISTRIBUTION AND CONTRIBUTION 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, 2011, 2010, and 2009, we paid distributions to our general partners of $198.1 million, $171.9 million, and $151.5 million, respectively. In 2011, we received contributions from our general partners in the amount of $109.6 million. During the third quarter of 2011, we received an equity contribution from our general partners in the amount of $99.6 million for the previously approved 2011 equity contribution. The proceeds were used to repay indebtedness. In the fourth quarter of 2011, we received a $10 million contribution, which was used to fund 50 percent of the costs of construction of the Princeton Lateral Project. 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.

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, 2011, 2010, and 2009, our charges from TransCanada and its affiliates totaled approximately $28.7 million, $25.8 million, and $25.5 million, respectively.

For the years ended December 31, 2011, 2010, and 2009, 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) and ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), subsidiaries of ONEOK, for 2011, 2010, and 2009 was $4.4 million, $4.1 million, and $4.2 million, respectively. At December 31, 2011 and 2010, we had outstanding receivables from ONEOK Energy and ONEOK Rockies of $0.5 million and $0.3 million, respectively.

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 $50 million was declared and paid on February 1, 2012 for the fourth quarter of 2011.

We have evaluated subsequent events through February 13, 2012, 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:

2011 Credit Agreement	$200 million amended and restated revolving Credit Agreement for Northern Border
Acquisitions	The acquisition from subsidiaries of TransCanada of a 25 percent membership interest in each of GTN and Bison
AFUDC	Allowance for funds used during construction
ANR	ANR Pipeline Company
ASC	Accounting Standards Codification
Bcf/d	Billion cubic feet per day
BIA	Bureau of Indian Affairs
Bison	Bison Pipeline LLC
CAA	Clean Air Act
CWA	Clean Water Act
Delaware Act	Delaware Revised Uniform Limited Partnership Act
DOT	U.S. Department of Transportation
DSUs	Deferred Share Units
EBITDA	Net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges
EPA	U.S. Environmental Protection Agency
EPNG	El Paso Natural Gas Company
ESA	The Endangered Species Act
Essar	Essar Steel Minnesota LLC
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Gas exiting the WCSB	Net supply of natural gas for export from 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.
GHG	Greenhouse Gas
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 LLC
GTN Settlement	Stipulation and Agreement of Settlement for GTN regarding its rates and terms and conditions of service

HCAs	High consequence areas
IDRs	Incentive Distribution Rights
IMP	Integrity Management Program
IRS	Internal Revenue Service
KPMG	KPMG LLP
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
Mainline	TransCanada's Mainline, a natural gas transmission system extending from the Alberta/Saskatchewan border east to Quebec
MBT	Michigan Business Tax
MDth/d	Thousand dekatherms per day
MAOP	Maximum allowable operating pressure
MMcf/d	Million cubic feet per day
NASDAQ	NASDAQ Global Select Market
NEPA	National Environmental Policy Act
NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
NV Energy	Sierra Pacific Power Company d/b/a NV Energy
NYSE	New York Stock Exchange
Old IDRs	IDRs available to the General Partner under the Amended and Restated Agreement of Limited Partnership
Other Pipes	North Baja and Tuscarora
Our pipeline systems	Our ownership interests in Great Lakes, Northern Border, GTN, Bison, North Baja and Tuscarora
Partnership	TC PipeLines, LP and its subsidiaries
Partnership Agreement	Second Amended and Restated Agreement of Limited Partnership
PCBs	Polychlorinated biphenyls
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
Pipeline Safety Act	The Pipeline Safety Improvement Act of 2002
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
PUCN	Public Utilities Commission of Nevada
Revised IDRs	IDRs available to the General Partner under the Second Amended and Restated Agreement of Limited Partnership
RREI	Rolls Royce Energy Systems, Inc

SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP's revolving credit and term loan agreement
TransCan Northern	TransCan Northern Ltd.
TransCanada	TransCanada Corporation and its subsidiaries
TSCA	Toxic Substances Control Act
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora Settlement	Stipulation and Agreement of Settlement for Tuscarora regarding its rates and terms and conditions of service
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

Unless the context clearly indicates otherwise, TC PipeLines, LP, its subsidiaries and equity investees are collectively referred to in this annual report as "we," "us," "our" and "the Partnership." We use "our pipeline systems" when referring to the Partnership's ownership interests in Great Lakes Gas Transmission Limited Partnership (Great Lakes), Northern Border Pipeline Company (Northern Border), Gas Transmission Northwest LLC (GTN), Bison Pipeline LLC (Bison), North Baja Pipeline, LLC (North Baja) and Tuscarora Gas Transmission Company (Tuscarora).

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(4) Chair, Audit Committee
(5) Member, Conflicts Committee

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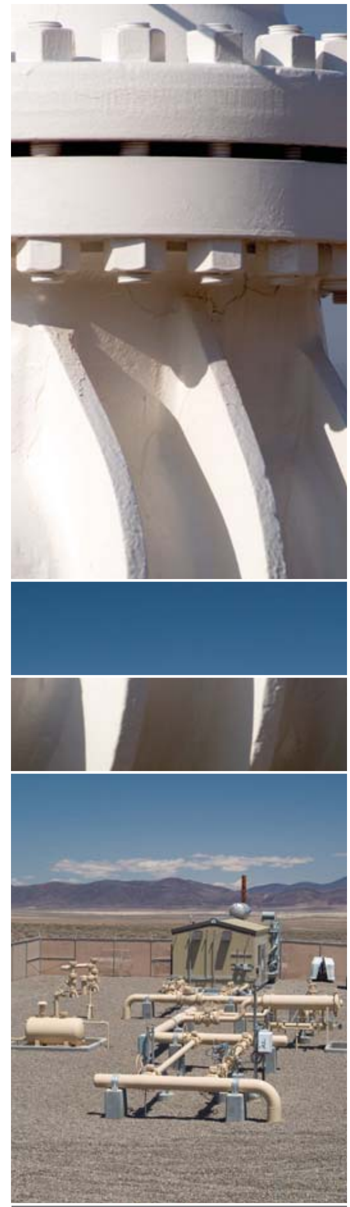

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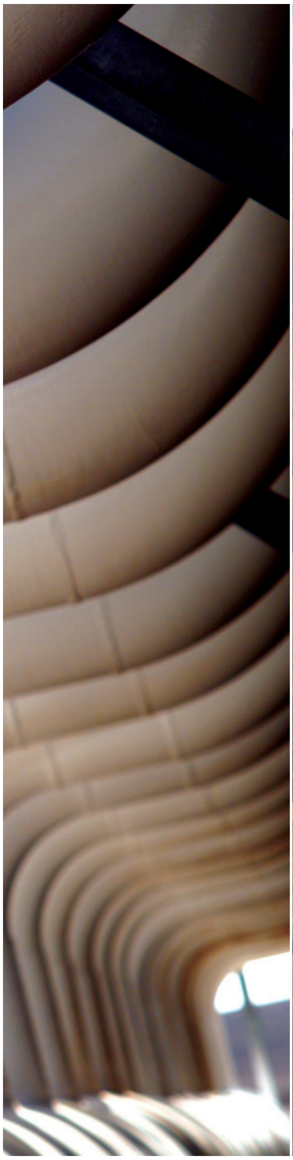

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