TC PIPELINES LP
Form 10-K
February 26, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2015

or

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

For the transition period from to
Commission File Number: 001-35358

TC PipeLines, LP
(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	**52-2135448** (I.R.S. Employer Identification No.)
700 Louisiana Street, Suite 700 **Houston, Texas** (Address of principal executive offices)	**77002-2761** (Zip code)

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

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

Title of each class	Name of each exchange on which registered
Common units representing limited partner interests	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a small reporting company)	Small Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2015 was approximately $2.7 billion.

As of February 22, 2016, there were 64,317,449 common units of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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

Definitions

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

2013 Acquisition	Acquisition of an additional 45 percent membership interest in each of GTN and Bison by the Partnership to increase ownership to 70 percent on July 1, 2013
2013 Term Loan Facility	TC PipeLines, LP's term loan credit facility under a term loan agreement dated July 1, 2013
2014 Bison Acquisition	Partnership's acquisition of the remaining 30 percent interest in Bison on October 1, 2014
2015 GTN Acquisition	Partnership's acquisition of the remaining 30 percent interest in GTN on April 1, 2015
2015 Term Loan Facility	TC PipeLines, LP's term loan credit facility under a term loan agreement dated September 30, 2015
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM program	At-the-market Equity Issuance Program
Bison	Bison Pipeline LLC
Carty Lateral	GTN lateral pipeline in north-central Oregon that delivers natural gas to a power plant owned by Portland General Electric Company
Consolidated Subsidiaries	GTN, Bison, North Baja and Tuscarora
Delaware Act	Delaware Revised Uniform Limited Partnership Act
DOT	U.S. Department of Transportation
Dth/day	Dekatherms per day
DSUs	Deferred Share Units
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
General Partner	TC PipeLines GP, Inc.
GHG	Greenhouse Gas
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest LLC

HCAs	High consequence areas
IDRs	Incentive Distribution Rights
IRS	Internal Revenue Service
KPMG	KPMG LLP
LDCs	Local Distribution Companies
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

NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
NYSE	New York Stock Exchange
Our pipeline systems	Our ownership interests in GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora and, effective January 1, 2016, PNGTS
Partnership	TC PipeLines, LP including its subsidiaries, as applicable
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
PNGTS Acquisition	Partnership's acquisition of a 49.9 percent interest in PNGTS on January 1, 2016
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP's senior credit facility under revolving credit agreement as amended and restated, dated December 23, 2015
Short-Term Loan Facility	TC PipeLines, LP short-term loan facility under loan agreement dated October 1, 2014
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin
Wholly-owned subsidiaries	GTN, Bison, North Baja, and Tuscarora

Unless the context clearly indicates otherwise, TC PipeLines, LP and its subsidiaries are collectively referred to in this annual report as "we," "us," "our" and "the Partnership." We use "our pipeline systems" and "our pipelines" when referring to the Partnership's ownership interests in Gas Transmission Northwest LLC (GTN), Northern Border Pipeline Company (Northern Border), Bison Pipeline LLC (Bison), Great Lakes Gas Transmission Limited Partnership (Great Lakes), North Baja Pipeline, LLC (North Baja), Tuscarora Gas Transmission Company (Tuscarora), and effective January 1, 2016, Portland Natural Gas Transmission System (PNGTS).

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, market or competitive conditions, regulations, organic or 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 actual results and our financial condition to differ materially from those contemplated in forward-looking statements include, but are not limited to:

- the ability of our pipeline systems to sell available capacity on favorable terms and renew expiring contracts which are affected by, among other factors:
  - demand for natural gas;
  - changes in relative cost structures and production levels of natural gas producing basins;
  - natural gas prices and regional differences;
  - weather conditions;
  - availability and location of natural gas supplies in Canada and the United States (U.S.) in relation to our pipeline systems;
  - competition from other pipeline systems;
  - natural gas storage levels; and
  - rates and terms of service;
- the performance by the shippers of their contractual obligations on our pipeline systems;
- the outcome and frequency of rate proceedings or settlement negotiations on our pipeline systems;
- changes in the taxation of master limited partnership investments by state or federal governments such as final adoption of proposed regulations narrowing the sources of income qualifying for partnership tax treatment or the elimination of pass-through taxation or tax deferred distributions;
- increases in operational or compliance costs resulting from 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) and U.S. Department of Transportation (DOT);

the impact of recent significant declines in oil and natural gas prices, including the effects on the creditworthiness of our shippers;

our ongoing ability to grow distributions through acquisitions, accretive expansions or other growth opportunities, including the timing, structure and closure of further potential acquisitions;

potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner), TransCanada and us;

the ability to maintain secure operation of our information technology;

the impact of any impairment charges;

- cybersecurity threats, acts of terrorism and related distractions;
- operating hazards, casualty losses and other matters beyond our control; and
- the level of our indebtedness, including the indebtedness of our pipeline systems, increase of interest rates, and the availability of capital.

These and other risks are described in greater detail in Part I, Item 1A. "Risk Factors." All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Given these uncertainties, you should not place undue reliance on these forward-looking statements. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. All forward-looking statements are made only as of the date made and except as required by applicable law, we undertake no obligation to update any forward-looking statements to reflect new information, subsequent events or other changes.

Item 1. Business

NARRATIVE DESCRIPTION OF BUSINESS

General

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

We are managed by our General Partner, which is an indirect, wholly-owned subsidiary of TransCanada. Through its subsidiaries, TransCanada owns approximately 26.6 percent of our common units, 100 percent of our Class B units, 100 percent of our incentive distribution rights (IDRs) and an effective two percent general partner interest in us. See Part II, Item 5. "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for more information regarding TransCanada's ownership in us.

Recent Business Developments

On April 23, 2015, the board of directors of our General Partner declared the Partnership's first quarter 2015 cash distribution in the amount of $0.84 per common unit, payable on May 15, 2015 to unitholders of record as of May 5, 2015.

On July 23, 2015, the board of directors of our General Partner declared the Partnership's second quarter 2015 cash distribution in the amount of $0.89 per common unit, payable on August 14, 2015 to unitholders of record as of August 4, 2015. The declared distribution reflected a $0.05 per common unit increase to the first quarter 2015 cash distribution.

On October 22, 2015, the board of directors of our General Partner declared the Partnership's third quarter 2015 cash distribution in the amount of $0.89 per common unit payable on November 13, 2015 to unitholders of record as of November 3, 2015.

On January 21, 2016, the board of directors of our General Partner declared the Partnership's fourth quarter 2015 cash distribution in the amount of $0.89 per common unit payable on February 12, 2016 to unitholders of record as of February 2, 2016.

The first quarter 2015 distribution exceeded the first target of the General Partner's IDRs by $0.03 per common unit, resulting in an increase in the distribution on the General Partner interest from 2 percent to 15 percent on the incremental distribution in excess of the first target.

The second, third and fourth quarter 2015 distributions exceeded the first and second targets of the General Partner's IDRs by $0.07 and $0.01 per common unit, respectively, resulting in an increase in the distribution on the General Partner interest from 2 percent to 15 percent on the incremental distribution in excess of the first target and from 15 percent to 25 percent on the incremental distribution in excess of the second target.

Debt Offering On March 13, 2015, the Partnership closed a $350 million public offering of senior unsecured notes bearing an interest rate of 4.375 percent maturing March 13, 2025. The net proceeds of $346 million were used to fund a portion of the 2015 GTN Acquisition and reduce the amount outstanding under our Senior Credit Facility.

GTN Acquisition On April 1, 2015, the Partnership acquired the remaining 30 percent interest in GTN from a subsidiary of TransCanada (2015 GTN Acquisition). The total purchase price of the 2015 GTN Acquisition was $446 million plus purchase price adjustments. The purchase price consisted of $264 million in cash (including the final purchase price adjustment of $11 million), the assumption of $98 million in proportional GTN debt and the issuance of $95 million of new Class B units to TransCanada.

GTN Settlement On June 30, 2015, FERC approved GTN's rate settlement as filed on April 23, 2015. The 2015 rate settlement satisfies GTN's obligations from its 2011 rate settlement for new rates to be in effect on January 1, 2016 and reduced rates on the mainline by three percent on July 1, 2015 (GTN Settlement). Beginning January 1, 2016, the rates decreased a further 10 percent. We expect any near term impact of the rate reduction to GTN's revenue will in part be offset by increased contracting and other revenue opportunities on the system as well as revenue from the Carty Lateral which was placed in-service in October 2015. See Regulatory and Rate Proceedings within Item 1. "Business Government Regulation" for further information.

Great Lakes On October 15, 2015, FERC accepted and approved a settlement regarding transportation service rates payable to Great Lakes from its TransCanada affiliate, ANR Pipeline Company (ANR). As a result of this settlement, Great Lakes recognized the deferred transportation revenue of approximately $23 million in the fourth quarter of 2015, inclusive of an approximate $9 million of revenue related to services performed in 2014. See Regulatory and Rate Proceedings within Item 1. "Business" of this document for detailed disclosure regarding Great Lakes suspended contracts with ANR.

GTN's Carty Lateral In October 2015, GTN placed the Carty Lateral in-service. The lateral was constructed in north-central Oregon to deliver natural gas to an electric generation facility owned by Portland General Electric Company. Portland General Electric Company has a 30-year contract for 100 percent of Carty Lateral's capacity that began in 2015 and a 20-year GTN mainline contract for 75,000 dekatherms/day that is expected to begin in 2016.

PNGTS Acquisition On January 1, 2016, the Partnership acquired a 49.9 percent interest in PNGTS from a subsidiary of TransCanada (PNGTS Acquisition). The total purchase price of the PNGTS Acquisition was $223 million plus preliminary purchase price adjustments of $3 million. The purchase price consisted of $191 million in cash (including the preliminary purchase price adjustment of $3 million) and the assumption of $35 million in proportional PNGTS debt. This transaction adds a new market geography for us, further diversifying our cash flow stream and extending our breadth of operations.

Great Lakes Impairment For the year ended December 31, 2015, we determined that the carrying value of our investment in Great Lakes was in excess of its fair value and that the decline is not temporary. Accordingly, we concluded that the carrying value of our investment in Great Lakes was impaired resulting in a fourth quarter impairment charge of $199 million, reflected as Impairment of equity-method investment on our Statement of Income. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Impairment of Equity Investments, Goodwill and Long-Lived Assets Equity Investments" for further information regarding the impairment of our equity investment in Great Lakes.

Business Strategies

Our strategy is to invest in long-life 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 distributable cash flows over the long-term through efficient utilization of our pipeline systems and appropriate business strategies, while maintaining a commitment to safe and reliable operations.

Understanding the Natural Gas Pipeline Business

Natural gas pipelines move natural gas from major sources of supply or upstream pipelines to downstream pipelines or locations or markets that use natural gas to meet their energy needs. Pipeline systems include meter stations that record how much natural gas comes on to the pipeline and how much exits at the delivery locations; compressor stations that act like pumps to move the large volumes of natural gas along the pipeline; and the pipelines themselves that transport natural gas under high pressure.

Regulation, rates and cost recovery

Interstate natural gas pipelines are regulated by FERC. FERC approves the construction of new pipeline facilities and regulates aspects of our business including the maximum rates that are allowed to be charged. Maximum rates are based on operating costs, which include allowances for operating and maintenance costs, income and property taxes, interest on debt, depreciation expense to recover invested capital and a return on the capital invested. Although FERC regulates maximum rates for services, interstate natural gas pipelines frequently face competition and therefore may choose to discount their services in order to compete.

Because FERC rate reviews are periodic and not annual, actual revenues and costs typically vary from those projected during the rate case. If revenues no longer provide a reasonable opportunity to recover costs, a pipeline can file with FERC for a determination of new rates, subject to any moratoriums in effect. FERC also has the authority to initiate a review to determine whether a pipeline's rates of return are just and reasonable. Sometimes a settlement or agreement with the pipeline shippers is achieved, which may include mutually beneficial performance incentives. FERC must approve the components of any settlement.

Contracting

New pipeline projects are typically supported by long-term contracts. The term of the contracts is dependent on the individual developer's appetite for risk and is a function of expected rates of return and stability and certainty of returns. Transportation contracts expire at varying times and underpin varying amounts of capacity. As existing contracts approach their expiration dates, efforts are made to extend and/or renew the contracts. If market conditions are not favorable at the time of renewal, transportation capacity may remain uncontracted, be contracted at lower rates or be contracted on a shorter-term basis. Unsold capacity may be recontracted if and when market conditions become more favorable. The ability to extend and/or renew expiring contracts and the terms of such subsequent contracts will depend upon the overall commercial environment for the gas transportation and consumption.

Business environment

The North American natural gas pipeline network has been developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supply and changing market demand.

The map below shows the location of the North American basins in relation to our pipeline systems together with those of our General Partner, TransCanada Corporation.

Supply

Natural gas is primarily transported from producing regions and, in limited circumstances, from liquefied natural gas (LNG) import facilities to market hubs or interconnects for distribution to natural gas consumers. Recent development of shale and other unconventional gas reserves has resulted in increases in overall North American natural gas production and economically recoverable reserves.

There has been an increase in production from the development of shale gas reserves that are located close to traditional markets, particularly in the Northeastern U.S. This has increased the number of supply choices for natural gas consumers resulting in changes to historical natural gas pipeline flow patterns.

The supply of natural gas in North America is expected to continue increasing significantly over the next decade and over the long-term for a number of reasons, including the following:

- use of technology, including horizontal drilling in combination with multi-stage hydraulic fracturing, is allowing companies to access unconventional resources economically. This is increasing the technically accessible resource base of existing and emerging gas basins; and

- application of these technologies to existing oil fields where further recovery of the existing resource is now possible. There is often associated gas discovered in the exploration and production of liquids-rich hydrocarbons (for example the Bakken oil fields), which also contributes to an increase in the overall gas supply for North America.

Other factors that can influence the overall level of natural gas supply in North America include:

- the price of natural gas   low prices in North America may increase demand but reduce drilling activities that in turn diminish production levels, particularly in dry natural gas fields where the extra revenue generated from the associated liquids is not available. High natural gas prices may encourage higher drilling activities but may decrease the level of demand;

- producer portfolio diversification   large producers often diversify their portfolios by developing several basins but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of pipeline transportation services. Basin-on-basin competition impacts the extent and timing of a resource development that, in turn, drives changing dynamics for pipeline capacity demand; and

- regulatory and public scrutiny   changes in regulations that apply to natural gas production and consumption could impact the cost and pace of development of natural gas in North America.

Demand

The natural gas pipeline business ultimately depends on a shipper's demand for pipeline capacity and the price paid for that capacity. Demand for pipeline capacity is influenced by, among other things, supply and market competition, economic activity, weather conditions, natural gas pipeline and storage competition, and the price of alternative fuels.

The growing supply of natural gas has resulted in relatively low natural gas prices in North America which has supported increased demand for natural gas particularly in the following areas:

- natural gas-fired power generation;

- petrochemical and industrial facilities;

- the production of Alberta's oil sands, although new greenfield projects that have not begun construction may be delayed in the current low oil price environment;

- exports to Mexico to fuel electric power generation facilities; and

- exports from North America to global markets through a number of proposed LNG export facilities.

Commodity Prices

In general, the profitability of the natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and its price impact can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and / or new gas pipeline infrastructure.

Competition

Competition among natural gas pipelines is based primarily on transportation rates and proximity to natural gas supply areas and consuming markets. Changes in supply locations and regional demand have resulted in changes to pipeline flow dynamics. Where pipelines historically transported natural gas from one or two supply sources to their markets under long-term contracts, today many pipelines transport gas in multiple directions and under shorter contract terms. Some pipelines have even reversed their flows in order to adapt to changing sources of supply. Competition among pipelines to attract supply and new or existing markets to their systems has also increased across North America.

Our Pipeline Systems

We have four wholly-owned pipelines and equity ownership interests in three natural gas interstate pipeline systems that are collectively designed to transport approximately 9.1 billion cubic feet per day of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western, Midwestern and Eastern U.S. All of our pipeline systems are operated by subsidiaries of TransCanada.

Our pipeline systems include:

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends between an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100%
Northern Border	1,408 miles	Extends between the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Williston Basin and Rocky Mountain area for deliveries to the Midwest. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50%
Bison	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison transports natural gas from the Powder River Basin to Midwest markets.	100%
Great Lakes	2,115 miles	Connects with the TransCanada Mainline at the Canadian border near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TransCanada owns the remaining 53.55 percent of Great Lakes.	46.45%
North Baja	86 miles	Extends between an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100%
Tuscarora	305 miles	Extends between the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100%
PNGTS	295 miles	Connects with the TransQuebec and Maritimes Pipeline (TQM) at the Canadian border to deliver natural gas to customers in the U.S. northeast. TransCanada owns 11.81 percent of PNGTS. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS.	49.9%[(a)]

(a) Effective January 1, 2016. See Note 22 within Part IV, Item 15. "Exhibits and Financial Statements Schedules" for further information.

The map below shows the location of our pipeline systems.

Customers, Contracting and Demand

Our customers are generally large utilities, local distribution companies (LDCs) and major natural gas marketers and producing companies, and other interstate pipelines, including affiliates. 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 on a firm or interruptible basis. The majority of our pipeline systems' natural gas transportation services are provided through firm service transportation contracts with a reservation or demand charge that 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 or customers. Customers with interruptible service transportation agreements may utilize available capacity after firm service transportation requests are satisfied.

Our pipeline systems actively market their available capacity and work closely with customers, including natural gas producers, LDC's, marketers and end users, to ensure our pipelines are offering attractive services and competitive rates. Approximately 74 percent of our long-term contract revenues are with customers who have an investment grade rating or who have provided guarantees from investment grade parties. We have obtained financial assurances as permitted by FERC and our tariffs for the remaining long-term contracts. See Part I, Item 1A. "Risk Factors."

Two of our customers, Anadarko Energy Services Company and Pacific Gas and Electric Company, account for a significant portion of our revenue and comprised 14 percent and 12 percent, respectively, of the Partnership's revenues in 2015.

GTN GTN's revenues are substantially supported by long-term contracts, the majority of which are expiring prior to 2023. These contracts are primarily held by LDCs that historically use a diversified portfolio of transportation options to serve their long-term markets and marketers contracting under a variety of contract terms. We expect GTN to continue to be an important transportation component of these diversified portfolios. Incremental transportation opportunities are based on the difference in value between Western Canadian supplies and deliveries to Northern California. GTN's rates were established based on its current contracted long-term capacity. GTN continues to market its remaining long-term capacity.

Northern Border   Northern Border's revenues are substantially supported by firm transportation contracts through March 2017. As contracts have expired, market conditions have enabled Northern Border to negotiate contract extensions that are typically for terms of two years or longer. Its uncontracted capacity is subject to seasonal demand for transportation services, which has traditionally been strongest during peak winter months to serve heating demand and peak spring/summer months to serve electric cooling demand and storage injection.

Great Lakes   Great Lakes' revenue is derived from shorter-term contracts for short-haul and long-haul transportation. A majority of these contracts are with TransCanada and affiliates on multiple paths across its system. Great Lakes' ability to sell its available and future capacity will depend on future market conditions which are impacted by a number of factors including weather, levels of natural gas in storage, the capacity of upstream and downstream pipelines, and the availability and pricing of natural gas supplies. Demand for Great Lakes' services has historically been highest in the summer to fill the natural gas storage complexes in Ontario and Michigan in advance of the upcoming winter season. During the winter, Great Lakes serves peak heating requirements for customers in Minnesota, Wisconsin, Michigan and beyond.

PNGTS   Approximately 50 percent of PNGTS' current revenue stream is driven by long-term contracts that expire in 2019 with the remaining 50 percent driven by short-term contracts. PNGTS recently completed an open season for additional contract volumes. Additional contract commitments are expected to begin in 2017 with expiration in 2032. Its uncontracted capacity is subject to seasonal demand for transportation services, which has traditionally been strongest during peak winter months to serve heating demands of the area. PNGTS is continuing to market its remaining long-term capacity.

Other Pipelines   Bison, North Baja and Tuscarora revenues are substantially supported by long-term contracts through 2020.

Competition

Overall, our pipeline systems generate a substantial portion of their cash flow from long-term firm contracts for transportation services and are therefore insulated from competitive factors during the terms of the contracts. If these long-term contracts are not renewed at their expiration, our pipeline systems face competitive pressures which influence contract renewals and rates charged for transportation services.

Three of our pipeline systems, GTN, Northern Border, and Great Lakes, compete with each other for WCSB natural gas supply as well as with other pipelines, including TransCanada's Mainline system, the Alliance pipeline and the Westcoast pipeline. Northern Border and Great Lakes compete in their respective market areas for natural gas supplies from other basins as well, such as the Rocky Mountain area, Mid-Continent, Gulf Coast, Utica and Marcellus basins. GTN primarily competes with pipelines supplying natural gas into California and Pacific Northwest markets.

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

North Baja's southbound pipeline 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 area, Permian and San Juan basin natural gas into the Southern California area.

Tuscarora competes for deliveries primarily into the northern Nevada natural gas market with natural gas from the Rocky Mountain area.

PNGTS connects with TQM at the Canadian border and shares facilities with the Maritimes and Northeast Pipeline from Westbrook, Maine to a connection with the Tennessee Gas Pipeline System near Boston, Massachusetts. PNGTS competes with LNG supplies and production from eastern Canada transported on Maritimes and Northeast and with LNG delivered into Boston. Tennessee Gas Pipeline and Algonquin Gas Transmission also compete with PNGTS for gas deliveries into New England markets.

Relationship with TransCanada

TransCanada is the indirect parent of our General Partner and owns, through its subsidiaries, approximately 26.6 percent of our common units, 100 percent of our Class B units, 100 percent of our IDRs and an effective two percent general partner interest in us. TransCanada is a major energy infrastructure company, listed on the Toronto Stock Exchange and NYSE, with more than 65 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 $64 billion Canadian in total assets, including a 41,900 mile network of natural gas pipelines, 2,640 miles of wholly-owned oil pipelines and over 350 billion cubic feet of storage capacity. TransCanada also owns, controls or is developing over 13,100 megawatts of power generation.

TransCanada operates our pipeline systems and, in some cases, contracts for pipeline capacity. We have purchased assets from TransCanada and jointly participated with TransCanada in acquiring assets from third parties, including acquisitions that we would have been unable to pursue on our own. TransCanada views the dropdown of its remaining U.S. natural gas pipeline assets into the Partnership as an important financing option as it executes its capital growth program, subject to actual funding needs and market conditions. There can be no assurance, however, as to when and on what terms these assets will be offered to the Partnership. See Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information on our relationship with TransCanada.

Government Regulation

Federal Energy Regulatory Commission

All of our pipeline systems are regulated by FERC under the Natural Gas Act of 1938 (NGA) and Energy Policy Act of 2005, which gives 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 counterparty credit support 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 rate options stated in our tariffs which are approved by FERC. Tariffs specify the general terms and conditions for pipeline transportation service including the rates that may be charged. 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 FERC. Pipelines are permitted to charge rates lower than the maximum tariff rates in order to compete. 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 and rates charged.

Regulatory and Rate Proceedings

GTN On June 30, 2015, FERC approved GTN's rate settlement as filed on April 23, 2015. The rate settlement satisfies GTN's obligations from its 2011 rate settlement for new rates to be in effect on January 1, 2016 and the 2015 settlement reduced rates on the mainline by three percent on July 1, 2015. In January 2016, GTN's rates decreased a further 10 percent and will continue in effect through December 31, 2019. Unless superseded by a subsequent rate case or settlement, GTN's rates will decrease an additional eight percent for the period January 1, 2020 through December 31, 2021 when GTN will be required to establish new rates.

Northern Border Northern Border has a FERC-approved settlement agreement which established maximum long-term transportation rates and charges on the Northern Border system effective January 1, 2013 and requires Northern Border to file for new rates no later than January 1, 2018.

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

Great Lakes Great Lakes operates under rates established pursuant to a settlement approved by FERC in November 2013. Under the settlement, Great Lakes is required to file for new rates to be effective no later than January 1, 2018.

Effective November 1, 2014, Great Lakes executed contracts with an affiliate, ANR, to provide firm service in Michigan and Wisconsin. These contracts were at the maximum FERC authorized rate and were intended to replace historical contracts. On December 3, 2014, the FERC accepted and suspended Great Lakes' tariff records to become effective May 3, 2015, subject to refund. On February 2, 2015, FERC issued an Order granting a rehearing and clarification request submitted by Great Lakes, which allowed additional time for FERC to consider Great Lakes' request. Following extensive discussions with numerous shippers and other stakeholders, on April 20, 2015, ANR filed a settlement with FERC that included an agreement by ANR to pay Great Lakes the difference between the historical and maximum rates (ANR Settlement). Great Lakes provided service to ANR under multiple service agreements and rates through May 3, 2015 when Great Lakes' tariff records became effective and subject to refund. Great Lakes deferred $9 million of revenue related to services performed in 2014 and approximately $14 million of additional revenue related to services performed through May 3, 2015 under such agreements. On October 15, 2015, FERC accepted and approved the ANR Settlement. As a result, Great Lakes recognized the deferred transportation revenue of approximately $23 million in the fourth quarter of 2015.

North Baja North Baja continues to operate under the rates approved by FERC and has no requirement to file a new rate proceeding.

On January 6, 2014, FERC approved North Baja's application to temporarily abandon compression associated with the original design of its pipeline system up to three years. This temporary abandonment will preserve replacement options while reducing maintenance requirements and related expenses without any reduction in capacity or impact to existing firm transportation service.

Tuscarora On January 21, 2016, the FERC issued an Order (the January 21 Order) initiating an investigation pursuant to Section 5 of the NGA to determine whether Tuscarora's existing rates for jurisdictional services are just and reasonable. Tuscarora is currently preparing its response as required by the January 21 Order. We cannot predict the outcome or potential impact of this proceeding to Tuscarora at this time.

PNGTS PNGTS continues to operate under the rates approved by FERC in PNGTS' most recent rate proceeding, effective December 1, 2010. PNGTS has no requirement to file a new rate proceeding.

Environmental

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 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 required for construction and operations. Certain violations of environmental laws can result in the imposition of strict, joint and several liability. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and/or criminal penalties, the imposition of investigatory, remedial, and corrective action requirements, the occurrence of delays or restrictions in the permitting or performance of projects, and/or the issuance of orders enjoining future operations in affected areas.

The following is a discussion of some of the applicable environmental laws and regulations that relate to our business.

Solid Wastes and Hazardous Substance and Wastes Statutes The operations of our pipeline systems are subject to federal and state statutes that regulate the handling, management, storage and disposal of solid wastes, including hazardous wastes and hazardous substances. These include the Resource Conservation and Recovery Act, the Solid Waste Disposal Act and the Comprehensive Environmental Response, Compensation and Liability Act, on the federal level and comparable state statutes. These statutes subject our operations to rigorous waste management and disposal practices to ensure compliance. In addition, the improper disposal or a release of wastes or hazardous substance could result in the imposition of investigatory or remedial obligations.

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 pollutants or result in an increase of existing air pollutants. Such facilities must also comply with air permits containing various emission and operational limitations, or requiring the use of emission control or abatement technologies, which could result in the imposition of substantial costs on our operations. For example, in October 2015, the U.S. Environmental Protection Agency (EPA) issued a final rule under the CAA, lowering the National Ambit Air Quality Standards for ground-level ozone to 70 parts per billion. With EPA lowering the ground-level ozone standard, states may be required to implement more stringent regulations resulting in permitting delays or increased pollution control expenditures, which could apply to our operations in nonattainment areas.

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) and the Oil Pollution Act of 1990 (OPA) The CWA, OPA, 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 state waters and 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 federal regulations also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. The EPA released a final rule in May 2015 that attempted to clarify federal jurisdiction under the CWA over waters of the United States, but a number of legal challenges to this rule are pending, and implementation of the rule has been stayed nationwide. To the extent the rule expands the scope of the CWA's jurisdiction, pipeline construction and expansion projects could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

National Environmental Policy Act (NEPA) Natural gas transportation activities over federally-managed land or involving federal approval can be subject to review under NEPA, or analogous state requirements. NEPA requires federal agencies, including the Department of the Interior or FERC, to evaluate governmental 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 is 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 use on or of federal lands. NEPA reviews can take a significant amount of time and are subject to challenge by environmental groups, which have the potential to delay current and future natural gas transportation activities.

The Endangered Species Act (ESA) The ESA restricts activities that may affect endangered or threatened species or their habitats. The presence of threatened or endangered species, including 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 areas.

We have not incurred and do not anticipate incurring material costs to comply with existing environmental laws and regulations. We have not accrued for any environmental liabilities.

Greenhouse Gas

Scientific studies have suggested that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) may be contributing to warming of the Earth's atmosphere. The EPA has determined that emissions of GHGs present an endangerment to public health and the environment and subsequently has adopted regulations under existing provisions of the CAA that, among other things, establish construction and operating permit reviews regarding GHGs for certain large stationary sources that are already potential major sources of conventional pollutant emissions. The EPA has also promulgated regulations requiring the monitoring and reporting of GHG emissions from, among other sources, certain onshore natural gas transmission and storage facilities, including gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations, in the U.S., on an annual basis. Pursuant to President Obama's Strategy to Reduce Methane Emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025, in August 2015, the EPA proposed a suite of requirements and draft guidance related to the reduction in methane emissions from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, including proposed requirements for fugitive emissions of methane and new leak detection and repair requirements. The Pipeline and Hazardous Materials Safety Administration (PHMSA) is also expected to propose additional requirements to control methane emissions in the near future; however, we cannot predict what these requirements will be or their potential impact on our operations at this time.

Additionally, while the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, in the absence of any significant activity by Congress in recent years to adopt such legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These types of efforts may become more prevalent as a result of implementation of the EPA's Clean Power Plan (CPP), which is designed to limit GHG emissions from power plants; however, on February 9, 2015, the U.S. Supreme Court stayed implementation of the CPP pending outcome of all judicial challenges to the CPP. At this time, we cannot predict the outcome of this litigation. On an international level, the United States is one of almost 200 nations that agreed on December 12, 2015 to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are our customers, which could thereby reduce demand for our natural gas transportation services. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, it is uncertain if they would have an adverse effect on our financial condition and operations.

Safety

Our pipeline systems are subject to federal pipeline safety statutes, such as the Natural Gas Pipeline Safety Act of 1968 (NGPSA), the Pipeline Safety Improvement Act of 2002 (the PSI Act), the Pipeline Inspection, Protection, and Enforcement Act of 2006 (the PIPES Act), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the 2011 Pipeline Safety Act), as well as regulations promulgated and administered by the PHMSA. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities. Pursuant to the authority granted under the NGPSA, PHMSA has promulgated regulations governing pipeline design, installation, testing, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. The PSI Act established mandatory inspections for all U.S. natural gas transportation pipelines, and some gathering lines in high consequence areas (HCAs), which are areas where a release could have the most significant adverse consequences, including high population areas. The PIPES Act required mandatory inspections for certain natural gas transmission pipelines in HCAs and required that rulemaking be issued for, among other things, pipeline control room management. Pursuant to the authority granted under the NGPSA, as amended, PHMSA has established a series of rules requiring pipeline operators such as us to develop and implement integrity management programs for natural gas transmission pipelines in HCAs that require the performance of frequent inspections and other precautionary measures. PHMSA may assess penalties for violations of these and other requirements imposed by its regulations. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations.

The ongoing implementation of the pipeline 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 and to comply with the federal pipeline safety statutes and regulations. New laws and regulations related to pipeline safety could also adversely impact the operations of our pipeline systems. For example, in March 2015, PHMSA finalized new rules applicable to gas and hazardous liquid pipelines that, among other changes, impose new post-construction inspections, welding, gas component pressure testing requirements, as well as requirements related to maximum allowable operating pressure calculations. More recently, in December 2015, the Senate Commerce Committee approved the SAFE PIPES legislation, which will now be considered by the U.S. Senate. Among other things, the SAFE PIPES legislation would require PHMSA to conduct an assessment of its inspection process and integrity management programs for natural gas and hazardous liquid pipelines. While we cannot predict the outcome of these initiatives or future legislative or regulatory efforts, new laws and regulations related to pipeline inspection and integrity management requirements have the potential to adversely impact out business. Also, in July 2015, PHMSA published a Notice of Proposed Rulemaking (NPRM) that among other things, proposes to expand the Operator Qualification requirements from operations to construction, allows PHMSA to recover its costs to review the design and construction of significant projects, and requires a shorter notification period for incident and accident events. Industry groups and individual operators submitted extensive comments to the NPRM. PHMSA's response to the public comments will not be known until 2016 when the rule is finalized. It is not possible to determine the content of the rule, its effective date or the materiality of any cost impact to the pipelines until then.

It is anticipated that PHMSA will publish an NPRM to amend the pipeline safety regulations pertaining to integrity management of gas transmission pipelines in 2016. With one exception, most of the rulemaking is expected to have low-to-moderate cost impacts on the pipelines. However, in the event that the regulations are amended to require operators to verify pipe characteristics through activities such as pressure testing and materials testing, the costs could be significant. It is not possible to determine the content, the effective date, or the materiality of any cost impacts for the Final Rule associated with the NPRM until it is published. One additional NPRM is expected to be issued in 2016 addressing the remaining mandates in the 2011 Pipeline Safety Act. Once published, we will review the proposed rules to determine the ultimate impact on our pipeline systems. These proposed rulemakings could result in significant increased costs to any new or existing pipelines and the potential for temporary or permanent reductions in maximum allowable operating pressure, which would reduce available capacity on our pipelines.

There can be no assurance that future compliance with the requirements will not have a material adverse effect on our pipeline systems and the Partnership's financial position, operational costs, cash flow and our ability to maintain current distribution levels to the extent the increased costs are not recoverable through rates.

From time to time, despite compliance with applicable rules and regulations, our pipelines may experience incidents that result in leaks and ruptures that may impact the surrounding population and environment. This may result in enforcement by regulatory agencies that may seek civil and/or criminal fines and penalties, and could require our pipelines to conduct testing of the pipeline system or upgrade segments of a pipeline unrelated to the incident which costs may not be covered by insurance or recoverable through rate increases.

Other

On November 19, 2015, the Bureau of Indian Affairs published a final rule, Rights-of-Way on Indian Land; Final Rule (25 CFR 169) with the intended goal to update and streamline the process for obtaining BIA grants of rights-of-way (ROW) over and across tribal and individual Indian allotted land. The effective date of the rule is December 21, 2015. While many of the provisions simplify and expedite the process of negotiating and obtaining a ROW, certain provisions provide increased tribal authority over ROWs. As a result, tribes will have greater authority to enforce tribal laws as it relates to tax obligations for improvements, increased notification and consent for financing, and bonding requirements for restoration. The rule also sets forth additional requirements concerning real property that may affect new and existing agreements.

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, including valuation of our equity investments, 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 THE PARTNERSHIP

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we earn net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when losses are incurred and may not make cash distributions during periods when we earned profits.

Our ability to make cash distributions is dependent primarily on our cash flow, financial reserves and working capital borrowings.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate based on, among other things:

- the rates we charge for our transmission;
- legislative or regulatory action affecting the demand for natural gas, the supply of natural gas, the rates we can charge, how we contract for services, our existing contracts, operating costs and operating flexibility;
- the commodity price of natural gas, which could reduce the quantities of natural gas available for transport;
- the creditworthiness of our customers;
- changes in, or new, statutes, regulations or governmental policies by federal, state and local authorities with respect to protection of the environment;
- changes in accounting rules and/or tax laws or their interpretations;
- nonperformance or force majeure by, or disputes with or changes in contract terms with, major customers, suppliers, dealers, distributors or other business partners; and
- changes in, or new, statutes, regulations, governmental policies and taxes, or their interpretations.

Significant changes in energy prices could impact supply and demand balances for natural gas.

Prolonged low oil and natural gas prices can have a positive impact on demand but can negatively impact exploration and development of new natural gas supplies that could impact the availability of natural gas to be transported by our pipelines. Similarly, high commodity prices can increase levels of exploration and development but can reduce demand for natural gas leading to reduced demand for transportation services. Sustained low oil and natural gas prices could also impact shippers' creditworthiness that could impact their ability to meet their transportation service cost obligations.

If we do not successfully identify and complete expansion projects or make and integrate acquisitions that are accretive, we may not be able to continue to grow our cash distributions.

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. Our ability to complete successful, accretive expansion projects or acquisitions is dependent upon many factors, including our ability to secure necessary rights-of-way or regulatory approvals, our ability to finance such expansion projects or acquisitions on economically acceptable terms and the degree to which our assumptions about volumes, reserves, revenues, costs and customer commitments materialize. Acquisitions may not be available to the Partnership or occur at the prices, terms, with the same structure or on the schedule consistent with historical transactions.

TransCanada may offer its remaining U.S. natural gas pipeline assets to the Partnership, subject to TransCanada's actual funding needs and market conditions. There can be no assurance, however, as to when and on what terms these assets will be offered to the Partnership. Our ability to grow distributions depends upon the rate of acquisitions.

In addition, we face competition for acquisitions from investment funds, strategic buyers and commercial finance companies. These companies may have higher risk tolerances or different risk assessments that permit them to offer higher prices that we may be unwilling to match.

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:

- an inability to complete expansion projects on schedule or within the budgeted cost due to, among other factors, 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 completed expansion projects or acquisitions reduce our cash from operations on a per unit basis, our ability to make distributions may be reduced.

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, 2015, $795 million of our total $1,910 million of consolidated debt was subject to variable interest rates. As a result, our results of operations, cash flows and financial condition could be 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. As of December 31, 2015, the variable interest rate exposure related to $150 million of the $500 million 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements.

On January 25, 2016, we entered into a fixed interest rate swap related to the remaining $350 million of the $500 million 2013 Term Loan Facility, significantly reducing our debt subject to variable interest rates.

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

Our indebtedness may limit our ability to obtain additional financing, make distributions or pursue business opportunities.

The amount of the Partnership's current or future debt could have significant consequences to the Partnership including the following:

- our ability to obtain additional financing, if necessary, for working capital, acquisitions, payment of distributions or other purposes may be impaired or such financing may not be available on favorable terms;
- credit rating agencies may view our debt level negatively;

covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

our 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 our unitholders; and

our flexibility in responding to changing business and economic conditions may be limited.

In addition, our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance, the amount of our current maturities and debt maturing in the next several years, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the oil and gas markets or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities, or sell assets. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

If we are unable to obtain needed capital or financing on satisfactory terms to fund expansion projects or future acquisitions, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase.

Global financial markets and economic conditions have been, and continue to be, volatile, particularly for companies in the energy industry. The current weak economic conditions in the energy industry have made, and will likely continue to make, it difficult for some entities to obtain funding. In order to fund our expansion capital expenditures, we will be required to use cash from our operations, incur borrowings or sell additional common units or other limited partner interests. Using cash from operations will reduce distributable cash flow to our common unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, the covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate. If funding is not available to us when needed, or is available only on unfavorable terms, we may be unable to execute our business plans, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our financial condition, credit ratings, results of operations, cash flows and ability to make quarterly cash distributions to our unitholders

An impairment of our equity investment, our long-lived assets or goodwill could reduce our earnings or negatively impact the value of our common units.

Consistent with GAAP, we evaluate our goodwill for impairment at least annually and our equity investments and long-lived assets, including intangible assets with finite useful lives, whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test requires us to consider whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization.

As an example, during the fourth quarter of 2015, we recognized an impairment charge on our equity investment in Great Lakes amounting to $199 million. There can be no assurance no future impairment charge will be made with respect to our equity investments, goodwill and long-lived assets.

As of December 31, 2015, no impairment has been identified related to our equity investment in Northern Border, long-lived assets or goodwill.

For more information, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Impairment of Equity Investments, Goodwill and Long-Lived Assets Equity Investments."

We do not own a controlling interest in Northern Border, Great Lakes and PNGTS, which limits our ability to control these assets.

We do not own a controlling interest in Northern Border, Great Lakes and PNGTS 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 major policies of these assets are established by their management committees, which consist of individuals who are designated by each of the partners and including by us. The management committee requires at least the affirmative vote of a majority of the partners' percentage interests to take any action. Because of these provisions, without the concurrence of other partners, we would be unable to cause these assets to take or not to take certain actions, even though those actions may be in the best interests of the Partnership or these assets. Further, these assets may seek additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. In the event we elected not to, or were unable to, make a capital contribution to these assets; our ownership interest would be diluted.

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.

RISKS RELATED TO OUR PIPELINE SYSTEMS

We may experience changes in demand for our transportation services which may lead to an inability of our pipelines to charge maximum rates or renew expiring contracts.

Our primary exposure to market risk and competitive pressure occurs at the time existing shipper contracts expire and are subject to renegotiation and renewal. The value of our transportation services depends on a shipper's demand for pipeline capacity and the price paid for that capacity. The inability of our pipelines to extend or replace expiring contracts on comparable terms could have a material adverse effect on our business, financial condition, results of operations and our ability to make cash distributions. Our ability to extend and replace expiring contracts, particularly long-term firm contracts, on terms comparable to prior contracts, depends on many factors including:

- changes in upstream and downstream pipeline capacity, which could impact the pipeline's ability to contract for transportation services;
- 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;

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.

Rates and other terms of service for our pipeline systems are subject to approval and potential adjustment by FERC, which could limit their ability to recover all costs of capital and operations and negatively impact their rate of return, results of operations and cash available for distribution.

Our pipeline systems are subject to extensive regulation over virtually all aspects of their business, including the types and terms of services they may offer to their customers, construction of new facilities, creation, modification or abandonment of services or facilities, and the rates that they can charge to shippers. Under the NGA, their rates must be just, reasonable and not unduly discriminatory. Actions by FERC (see Item 1. "Business Government Regulation") could adversely affect our pipeline systems' ability to recover all of their current or future costs and could negatively impact their rate of return, results of operations and cash available for distribution.

We are dependent on the continued availability of and demand for, natural gas in relation to our pipeline systems.

As the long-term contracts on our pipeline systems expire, the demand for transportation service on our pipeline systems will depend on the availability of supply from the basins connected to our systems and the demand for natural gas in the markets we serve. Natural gas availability from basins depends upon numerous factors including basin production costs, production levels, availability of storage and natural gas prices. Our pipeline systems are also dependent on the continued demand for natural gas in their market areas. If supply and/or demand should significantly fall, our pipeline systems may be at risk for loss of contracting or contracting at discounted rates which could impact our revenues.

Our pipeline systems' business systems could be negatively impacted by security threats, including cyber security threats, and related disruptions.

In 2012, the U.S. Department of Homeland Security issued public warnings that indicate that pipelines and other assets might be specific targets of terrorist organizations or "cyber security" events. These potential targets might include our pipeline systems or operating systems and may affect our ability to operate or control our pipeline assets; their operations could be disrupted and/or customer information could be stolen.

We depend on the secure operation of our information technology to process, transmit and store electronic information, including information we use to safely operate our pipeline systems. Security breaches could expose our business to a risk of loss, misuse or interruption of critical information and functions that affect the pipeline operations. Such losses could result in operational impacts, damage to our assets, safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions, litigation and a potential material adverse effect on our operations, financial position and results of operations. There is no certainty that costs incurred related to securing against threats will be recovered through rates.

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 could 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 in the event of a rate proceeding, this could result in reductions in revenue, earnings and cash flows of our pipeline systems.

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

Our pipeline systems' respective debt levels could have negative consequences to each of them and the Partnership, 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 their 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, many of which are beyond their control.

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, among other events, earthquakes, adverse weather conditions and other natural disasters; terrorist activity or acts of aggression; damage to a pipeline by a third party; and, pipeline or equipment failures. Each of these risks could result in damage to one of our pipeline systems, business interruptions, release of pollution or contaminants into the environment and other environmental hazards, or injuries to persons and property. These risks could cause us to suffer a substantial loss of revenue and incur significant costs to the extent they are not covered by insurance under our pipeline systems' shipper contracts, as applicable. In addition, if one of our pipeline systems was to experience a serious pipeline failure, a regulator could require our pipelines to conduct testing of the 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 or face a potential reduction in operational parameters which could reduce the capacity available for sale.

Our pipelines could be subject to penalties and fines if they fail to comply with FERC regulations.

Our pipelines are subjected to substantial penalties and fines if the FERC finds that our pipeline systems have failed to comply with all applicable FERC-administered statutes, rules, regulations, and orders, or the terms of their tariffs on file with the FERC. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA and NGPA to impose penalties for violations of up to $1,000,000 per day for each violation, to revoke existing certificate authority and to order disgorgement of profits associated with any violation.

Our pipeline systems may experience significant costs and liabilities related to compliance with pipeline safety laws and regulations.

Our pipeline systems are subject to pipeline safety statutes and regulations administered by PHMSA, which require pipeline operators to develop integrity management programs.

The ongoing implementation of the pipeline 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 and to comply with the federal pipeline safety statutes and regulations. Additionally, any failure to comply with PHMSA's regulations could subject our pipeline systems to penalties, fines, or restrictions on our pipeline systems' operations.

The cost of new PHMSA regulations to our pipeline systems could have a material adverse effect on our operations, financial position, cash flows, and our ability to maintain current distribution levels to the extent the increased costs are not recoverable through rates.

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 is subject to federal, state and local environmental laws, regulations and enforcement policies and potential liabilities may arise related to protection of the environment and natural resources. Existing or new environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs. As an example, revisions to the National Ambient Air Quality Standards for ozone may result in the addition of non-attainment designations in additional counties in which our pipeline systems operate, which could result in additional permitting delays and expenditures for pollution control equipment. Also, changes to legislation, such as the Toxic Substances Control Act, may result in increased monitoring of chemicals present in the pipeline environment. 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.

In addition, under certain environmental laws and regulations, we may be exposed to substantial liabilities for pre-existing contamination that arise in connection with our past or current operations. For instance, although we do not have reportable information that requires corrective action at this time, during the installation, maintenance and operation of our pipeline systems, we may discover pre-existing conditions that may require us to notify, obtain and maintain permits and approvals issued by various federal, state and local governmental authorities, and to limit or prevent releases of materials from our operations in accordance with these permits and approvals, or install pollution control equipment. For instance, during routine maintenance activities, we may discover historical contamination, such as hydrocarbon, mercury, polychlorinated biphenyls, or heavy metals. This discovery may require notification to the appropriate governmental authorities and corrective action to address these conditions. 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 which may not be recoverable under their rates.

Current and future emissions regulation legislation or regulations restricting emissions of GHG could result in increased operating costs.

There have been a number of legislative initiatives to regulate GHG emissions; however, substantial uncertainty exists regarding the impact of new and proposed GHG laws and regulations. Moreover, implementation of GHG regulations is the subject of significant litigation which has created uncertainty in compliance requirements with both the regulatory agencies and industry. Pursuant to President Obama's Strategy to Reduce Methane Emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025, in August 2015, the EPA proposed a suite of requirements and draft guidance related to the reduction in methane emissions from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, including proposed requirements for fugitive emissions of methane and new leak detection and repair requirements. The PHMSA is also expected to propose additional requirements to control methane emissions in the near future; however, we cannot predict what these requirements will be or their potential impact on our operations at this time. We cannot estimate the effect of proposed and final regulations, and industry litigation on our future financial position, results of operations or cash flow. However, such legislation, regulation and litigation could materially increase their operating costs, including their cost of environmental compliance. Given the uncertainty of policy and regulatory schemes, the future effects on our pipelines cannot be predicted.

We are exposed to credit risk when a customer 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 pipelines' FERC approved tariffs limit the amount of credit support that they may require in the event that a customer's creditworthiness is or becomes unacceptable. If a significant customer has financial problems, which results in a delay or failure to pay for services provided by them or contracted for with them, it could have a material adverse effect on our business and results of operations.

Our pipelines do not own all of the land on which our pipelines are located, which could disrupt their operations.

Our pipelines do not own all of the land on which their pipelines have been constructed, and they are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if they do not have valid rights-of-way or if such rights-of-way lapse or terminate. They may obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. A loss of these rights, through their inability to renew right-of-way contracts or otherwise, could cause them to cease operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect their results of operations and their ability to make cash distributions to us.

RISKS RELATED TO OUR PARTNERSHIP STRUCTURE

We do not have the same flexibility as corporations to accumulate cash and equity to protect against illiquidity in the future.

We are required by our Third Amended and Restated Agreement of Limited Partnership of the Partnership (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 shortfall in the future, we may not be able to recapitalize by issuing more equity.

Common 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 members of the board of directors of our General Partner, including the independent directors, are appointed by its parent company and not by the unitholders.

Common unitholders cannot remove our General Partner without its consent.

Our General Partner may not be removed except by the vote of the holders of at least $66^2/_3$ percent of the outstanding common units. These required votes would include the votes of common units owned by our General Partner and its affiliates. TransCanada's ownership of 26.6 percent of our outstanding common units 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.

Our Partnership Agreement restricts voting and other rights of unitholders owning 20 percent or more of our common units.

The Partnership Agreement 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 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 and other partnership interests, without unitholder approval, which would dilute the existing unitholders' ownership interests. In addition, issuance of additional common units or other partnership interests may increase the risk that we will be unable to maintain the quarterly distribution payment at current levels.

Subject to certain limitations, we may issue additional common units and other partnership securities of any type, without the approval of 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. In addition, the issuance of additional common units may increase the risk that we will be unable to maintain the quarterly distribution payment at current levels.

Our common unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

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 common 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, 2015, the General Partner and its affiliates own approximately 26.6 percent of our outstanding common units.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties.

The Partnership Agreement contains provisions that eliminate the fiduciary standards to which the General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board of Directors;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our Board of Directors or to establish a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

The credit and business risk profiles of our General Partner and TransCanada could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner and TransCanada may be factors in credit evaluations of a master limited partnership because our General Partner can exercise control over our business activities, including our cash distribution and acquisition strategy and business risk profile. Other factors that may be considered are the financial conditions of our General Partner and TransCanada, including the degree of their financial leverage and their dependence on cash flows from us to service their indebtedness.

Costs reimbursed to our General Partner are determined by our General Partner and 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 each of the years ended December 31, 2015 and 2014, we paid fees and reimbursements to our General Partner in the amount of $3 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 with 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 U.S. federal income tax purposes, as well as us not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for U.S federal income tax purposes, or if we were to become subject to a material amount of entity level taxation for state tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. 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 to our unitholders (to the extent of our earnings and profits) would generally be taxed again to unitholders as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because of a tax imposed upon us as a corporation, the cash available for distribution to our unitholders would be substantially reduced. Any tax treatment of us 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.

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 or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal tax laws that affect publicly traded partnerships. In addition, President Obama has proposed a budget for fiscal year 2017 that calls for corporate taxation of publicly traded partnership beginning in 2022. We are unable to predict whether or not changes in the law regarding the treatment of publicly traded partnership, if any, will ultimately occur or become enacted.

At the state level, several states have either adopted or may be evaluating a variety of ways to subject partnerships and limited liability companies to entity level taxation. 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. Imposition of such taxes on our pipeline systems would reduce the cash available for distribution to us and for other business needs by our pipeline systems, and could adversely affect the amount of funds available for distribution to our unitholders.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017 in a manner that could substantially reduce cash available for distribution to you.

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, and the outcome of 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.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

Unitholders may be required to pay taxes on income from us, including their share of income from the cancellation of debt, 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 U.S. 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.

In response to current market conditions, we may engage in transactions to decrease the Partnership's financial leverage and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" (COD income) being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD 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 adjusted 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 adjusted 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 certain items such as potential 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, such as employee benefit plans and individual retirement accounts (IRAs), and non-U.S. 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 IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file federal income tax returns and pay tax on its share of our taxable income. Any tax-exempt entity or non-U.S. person should consult its tax advisor before investing in our common units.

We treat a purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization conventions that may 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 prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted for our 2015 taxable year and may not specifically authorize all aspects of our proration method thereafter. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets.

Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods, calculations or allocations could adversely affect the timing or 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 our capital and profits interest during any twelve-month period 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. For purposes of determining whether the 50 percent threshold has been met, multiple sales of the same interest will be counted only once.

Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one calendar year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in taxable income for the unitholder's taxable year that includes our termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for U.S. federal income tax purposes following the termination. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

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 U.S. 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 now or in the future, even if they do not live in any of those jurisdictions. 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 in multiple states. Many of these states currently impose a personal income tax on individuals. Generally, these states also impose income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is the unitholders' responsibility to file all required U.S. federal, state and local tax returns.

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.

Northern Border Approximately 90 miles of Northern Border's pipeline system is located within the boundaries of the Fort Peck Indian Reservation in Montana. Northern Border has a pipeline right-of-way lease with the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation, the term of which expires in 2061. 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. With the exception of one tract subject to a right-of-way grant expiring in 2035, the allotted lands are subject to a perpetual easement granted by the Bureau of Indian Affairs (BIA) for and on behalf of the individual allottees.

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. Great Lakes has right-of-way access, granted by the BIA, across allotted lands located within each reservation's boundaries that expire in 2018. Also, the Great Lakes pipeline crosses approximately 1,000 feet in two tracts under perpetual easement, located within the Chippewa Indian Reservation in Lower Michigan.

Please read Part I, Item 1. "Business Narrative Description of Business Government Regulation Other" for more information regarding legislation affecting easements on tribal land.

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 our pipeline systems' rate proceedings described in Item 1. "Business Government Regulation Regulatory and Rate Proceedings" is incorporated herein by reference. We are also a party to the following legal proceedings:

Employees Retirement System of the City of St. Louis v. TC PipeLines GP, Inc., et al. On October 13, 2015, an alleged unitholder of the Partnership filed a class action and derivative complaint in the Delaware Court of Chancery against the General Partner, TransCanada American Investments, Ltd. (TAIL) and TransCanada, and the Partnership as a nominal defendant. The complaint alleges direct and derivative claims for breach of contract, breach of the duty of good faith and fair dealing, aiding and abetting breach of contract, and tortious interference in connection with the 2015 GTN Acquisition, including the issuance by the Partnership of $95 million in Class B Units and amendments to the Partnership Agreement to provide for the issuance of the Class B Units. Plaintiff seeks, among other things, to enjoin future issuances of Class B Units to TransCanada or any of its subsidiaries, disgorgement of certain distributions to the General Partner, TransCanada and any related entities, return of some or all of the Class B Units to the Partnership, rescission of the amendments to the Partnership Agreement, monetary damages and attorney fees. The Partnership has moved to dismiss the complaint and intends to defend vigorously against the claims asserted.

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 its monthly payment obligation under its transportation services agreement with Great Lakes. Great Lakes sought to recover approximately $33 million for past and future payments due under the agreement. On September 16, 2015, following a jury trial, the federal district court judge entered a judgment in the amount of $32.9 million in favor of Great Lakes. On September 20, 2015, Essar appealed the decision to the United States Court of Appeals for the 8th Circuit (8th Circuit) based on an allegation of improper jurisdiction and a number of other rulings by the federal district judge. Essar was required to post a performance bond for the full value of the judgment pending appeal. The matter is expected to be heard by the 8th circuit in 2016.

Northern Border Pipeline Company v. State of South Dakota Department of Revenue On February 28, 2011, the South Dakota Department of Revenue (Department of Revenue) assessed a use tax in the amount of approximately $6 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. Following an unsuccessful rehearing, Northern Border received a favorable ruling on appeal by the South Dakota Circuit Court, Sixth Judicial Circuit, which decision was appealed by the Department of Revenue to the South Dakota Supreme Court. On August 5, 2015, the South Dakota Supreme Court issued its decision in favor of Northern Border, ruling that the Department of Revenue could not assess use tax on gas burned in compressors on Northern Border's pipeline located in South Dakota because Northern Border did not own the gas. The decision resulted in Northern Border's reversal of $15 million recorded liability, including interest and the related deferred asset on its books with no impact to the Partnership's earnings.

Item 4. Mine Safety Disclosures

None.

PART II

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

As of February 26, 2016, there were 42 registered holders of common units and approximately 12,200 beneficial owners of common units, including common units held in street name. Our common units trade on the NYSE under the symbol "TCP."

As of February 26, 2016, the Partnership had 64,317,449 common units outstanding, of which 47,232,618 were held by non-affiliates and 17,084,831 common units were held by subsidiaries of TransCanada, including 5,797,106 common units held by our General Partner. Additionally, TransCanada, thorough our General Partner, owns 100 percent of our IDRs and an effective two percent general partner interest in the Partnership. TransCanada also holds 100 percent of our 1,900,000 outstanding Class B units. There is no established public trading market for our IDRs and Class B units.

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported by the NYSE, and the amount of cash distributions declared per common unit 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	
2015			
First Quarter	**$73.76**	**$56.79**	**$0.84**
Second Quarter	**$71.35**	**$55.27**	**$0.89**
Third Quarter	**$61.74**	**$44.00**	**$0.89**
Fourth Quarter	**$55.85**	**$41.09**	**$0.89**
2014			
First Quarter	$48.57	$44.92	$0.81
Second Quarter	$53.25	$47.52	$0.84
Third Quarter	$68.37	$50.74	$0.84
Fourth Quarter	$80.46	$57.69	$0.84

On February 12, 2016, we paid a cash distribution of $59 million to common unitholders and the General Partner, representing a cash distribution of $0.89 per common unit for the quarter ended December 31, 2015. The distribution was allocated in the following manner: $57 million to the common unitholders as of the close of business on February 2, 2016 (including approximately $15 million to TransCanada as holder of 17,084,831 common units), and $2 million to the General Partner in respect of its effective two percent general partner interest, which includes $1 million of incentive distributions. In 2015, the Partnership made cash distributions to common unitholders and the General Partner that amounted to $228 million compared to $212 million in 2014.

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 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 provide that 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.

The first quarter 2015 distribution of $0.84 per common unit exceeded the first target of the General Partner's IDRs by $0.03 per common unit, resulting in an increase in the distribution on the General Partner interest from 2 percent to 15 percent on the incremental distribution in excess of the first target.

The second, third and fourth quarter 2015 distributions of $0.89 per common unit exceeded the first and second targets of the General Partner's IDRs by $0.07 and $0.01 per common unit, respectively, resulting in an increase in the distribution on the General Partner interest from 2 percent to 15 percent on the incremental distribution in excess of the first target and from 15 percent to 25 percent on the incremental distribution in excess of the second target.

In 2015, we paid incentive distributions to our General Partner of approximately $2 million (2014 $1 million).

Distributions to Class B units

On January 21, 2016, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $12 million which amount was paid on February 12, 2016. The Class B distribution represents an amount based upon 30 percent of GTN's distributable cash flow during the nine months ended December 31, 2015 less $15 million.

See Part II, Item 7. "Management's 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" for additional information about cash distributions.

Item 6. Selected Financial Data

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

(millions of dollars, except per common unit amounts)	**2015**	2014	2013[(a)]	2012[(a)]	2011[(a)]
Income Data (for the year ended December 31)					
Transmission revenues	**344**	336	341	343	353
Equity earnings from unconsolidated affiliates[(b)]	**97**	88	67	99	135
Impairment of equity-method investment[(c)]	**(199)**				
Net income	**20**	204	191	229	250
Net income attributable to controlling interests	**13**	172	155	192	216
Basic and diluted net (loss) income per common unit	**$(0.03)**	$2.67	$2.13[(d)]	$2.51[(d)]	$3.02 [(d)]
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$3.51**	$3.33	$3.21	$3.11	$3.06
Balance Sheet Data (at December 31)					
Total assets	**3,133**	3,349	3,443	3,505	3,625
Long-term debt (including current maturities)	**1,910**	1,695	1,578	1,013	1,067
Partners' equity	**1,151**	1,586	1,789	2,422	2,496

(a) Recast as discussed in Note 2 and Note 6 of the Partnership's consolidated financial statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules" of this report.

(b) Equity earnings represent our share in investee's earnings and does not include any impairment charge on equity method goodwill included as part of the carrying value of our investments in unconsolidated affiliates.

(c) During the fourth quarter of 2015, we recognized an impairment charge on our investment in Great Lakes amounting to $199 million. No impairment has been identified on our investment in Northern Border. Refer to Note 4 of the Partnership's consolidated financial statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules" of this report.

(d) Represents basic and diluted net income per common unit prior to recast.

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 Part IV, Item 15. "Exhibits and Financial Statements Schedules."

EXECUTIVE OVERVIEW

Net income (loss) attributable to controlling interests was $13 million or $(0.03) per common unit in 2015 compared to $172 million, or $2.67 per common unit in 2014. Adjusted earnings were $212 million or $3.03 per common unit in 2015, an increase of $40 million, or $0.36 per common unit over 2014 adjusted earnings.

Cash distributions declared per common unit increased five percent from $3.33 per common unit in 2014 to $3.51 per common unit in 2015.

EBITDA increased by seven percent to $365 million and Distributable cash flow increased by 14 percent to $291 million.

PNGTS Acquisition On January 1, 2016, we acquired a 49.9 percent interest in PNGTS from TransCanada for $223 million plus a preliminary purchase price adjustment of $3 million. The purchase price consisted of $191 million in cash (including the preliminary purchase price of $3 million) and the assumption of approximately $35 million in proportionate PNGTS debt. The Partnership funded the cash portion of the transaction using proceeds received from our ATM program and additional borrowings under our Senior Credit Facility. The purchase agreement provides for additional payments to TransCanada ranging from $5 million up to a total of $50 million if pipeline capacity is expanded to various thresholds during the fifteen year period following the date of closing.

PNGTS is a high-capacity, high-pressure interstate natural gas pipeline which began serving New England's energy needs in March 1999. The pipeline system is strategically located in the northeastern United States. The pipeline connects with the TQM Pipeline at the Canadian border and shares facilities with the Maritimes and Northeast Pipeline from Westbrook, Maine to a connection with the Tennessee Gas Pipeline System near Boston, Massachusetts.

This transaction adds a new market geography for us, further diversifying our cash flow stream and extending our breadth of operations. Continuing changes in the New England and Canadian Maritime gas markets in which PNGTS operates are expected which should lead to future growth opportunities for this pipeline system.

Investment in Great Lakes Impairment Charge Despite the recent improvement in income from our investment in Great Lakes since 2013, including favorable current year results, its long-term value has been adversely impacted by the changing natural gas flows in its market region as well as our conclusion in the fourth quarter that other strategic alternatives to increase its utilization or revenue were no longer feasible. As a result, we determined that the carrying value of our investment in Great Lakes was in excess of its fair value and the decline is not temporary. Accordingly, we concluded that the carrying value of our investment in Great Lakes was impaired.

Our analysis determined that the fair value of our investment in Great Lakes is $465 million, resulting in an impairment charge of $199 million in the fourth quarter of 2015, reflected as Impairment of equity-method investment on our Statements of Income for the year ended December 31, 2015.

Outlook of Our Business

TransCanada, the ultimate parent company of our General Partner, is currently executing a large capital program that includes $13 billion Canadian of near-term growth opportunities that are expected to be complete by 2018. Over the medium to longer-term, TransCanada is also advancing $45 billion Canadian of commercially secured large-scale projects, and various other initiatives backed by long-term contracts or cost-of-service business models. Depending on market conditions and actual funding needs, TransCanada views the dropdown of its remaining U.S. natural gas pipeline assets into the Partnership as an important financing option as it executes its capital growth program. There can be no assurance when and on what terms these assets will be offered to the Partnership.

The Partnership's financial performance is expected to benefit from its recent acquisitions, including the acquisition of an interest in PNGTS from TransCanada. Despite uncertainty in energy commodity prices, our portfolio of seven FERC-regulated interstate natural gas pipelines is expected to deliver generally stable results in 2016 due to ship-or-pay contracts with creditworthy customers.

HOW WE EVALUATE OUR OPERATIONS

We use certain non-GAAP financial measures that do not have any standardized meaning under GAAP because we believe they enhance the understanding of our operating performance. We use the following non-GAAP measures:

Adjusted earnings and Adjusted earnings per common unit

We have evaluated our financial performance and position inclusive of the impairment charge to our investment in Great Lakes recognized during the fourth quarter of 2015, however, we believe it is not reflective of our underlying operations during the periods presented. Therefore, these measures exclude the impact of the $199 million non-cash impairment charge.

EBITDA

We use EBITDA as a proxy of our operating cash flow and current operating profitability. It measures our earnings from our pipeline systems before certain expenses are deducted.

Distributable Cash Flows

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period.

RESULTS OF OPERATIONS

We believe that the following presentation of the earnings contribution from each of our pipeline systems will enhance investors' understanding of the way we analyze our financial performance. However, this presentation is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

Our equity interests in Northern Border and Great Lakes, and ownership of GTN, Bison, North Baja and Tuscarora were our only material sources of income in 2015. Therefore, our results of operations and cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems. See Part 1, Item 1. "Business."

(millions of dollars, except per common unit amounts)	**2015**	2014	2013[(a)]
Net income:			
GTN	**87**	72	75
Bison	**49**	46	46
North Baja	**24**	23	22
Tuscarora	**16**	17	16
Equity earnings:			
Northern Border	**66**	69	64
Great Lakes	**31**	19	3
Impairment of equity-method investment	**(199)**		
Partnership expenses	**(54)**	(42)	(35)
Net income	**20**	204	191
Net income attributable to non-controlling interests	**(7)**	(32)	(36)
Net income attributable to controlling interests	**13**	172	155
Adjusted earnings[(b)]	**212**	172	155
Net income (loss) per common unit	**(0.03)**	2.67	2.13
Adjusted earnings per common unit[(b)]	**3.03**	2.67	2.13

(a) Recast as discussed in Note 2 and Note 6 of the Partnership's consolidated financial statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules" of this report.

(b) Reconciled to the appropriate GAAP measures below.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014

Net income attributable to controlling interests decreased by $159 million to $13 million in 2015 compared to $172 million in 2014, resulting in a net loss per common unit during the year of $0.03 after allocations to the General Partner and to the Class B units. This decrease was primarily the result of the recognition of a $199 million non-cash impairment charge to our investment in Great Lakes (See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Impairment of Equity Investments, Goodwill and Long-Lived Assets Equity Investments.")

Adjusted earnings increased by $40 million, an increase of $0.36 per common unit. This increase was primarily due to the net effect of:

- higher net income from GTN mainly due to higher revenues from the sale of short-term services;

- higher net income from Bison mainly due to lower expenses related to pipeline integrity program spending and lower property taxes as compared to 2014;

lower equity earnings from Northern Border primarily due to lower revenues from the sale of short-term services as a result of the milder winter in 2015 compared to 2014;

higher equity earnings from Great Lakes primarily due to additional revenues from new contracts with ANR, a related party;

the acquisitions of the remaining interests in GTN and Bison whereby the Partnership now owns 100 percent of GTN and Bison effective April 1, 2015 and October 1, 2014, respectively; and higher partnership expenses due to the increase in interest expense related to additional borrowings to fund a portion of the remaining 30 percent interest in Bison (2014 Bison Acquisition) and the 2015 GTN Acquisition.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

Net income attributable to controlling interests and adjusted earnings increased $17 million to $172 million in 2014 compared to $155 million in 2013, an increase of $0.54 in both net income per common unit and adjusted earnings per common unit.

This increase was primarily due to the net effect of:

higher equity earnings from Northern Border and Great Lakes due to higher transportation revenues for the first quarter of 2014 from the sale of daily pipeline capacity during the winter months; and

higher Partnership expenses due to interest expense incurred in relation to the $500 million term loan obtained to finance a portion of the 2013 Acquisition.

Reconciliation of Net income attributable to controlling interest to adjusted earnings

Year Ended December 31 *(millions of dollars)*	**2015**	2014	2013
Net income attributable to controlling interests	**13**	172	155(a)
Add: Impairment of equity-method investment	**199**		
Adjusted earnings	**212**	172	155

(a) Recast as discussed in Note 2 and Note 6 of the Partnership's consolidated financial statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules" of this report.

Reconciliation of Net income (loss) per common unit to adjusted earnings per common unit

Year Ended December 31	**2015**	2014	2013
Net income (loss) per common unit-basic and diluted[(a)]	**(.03)**	2.67	2.13(c)
Add: per unit impact of impairment of equity-method investment	**3.06(b)**		
Adjusted earnings per common unit	**3.03**	2.67	2.13

(a) See Note 12 in Part IV, Item 15. "Exhibits and Financial Statement Schedules" for details of the calculation of net income (loss) per common unit basic and diluted.

(b) Computed by dividing the $199 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its effective two percent interest, by the weighted average number of common units outstanding during the period.

(c)

Represents basic and diluted net income per common unit prior to recast.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity include distributions received from our investments in partially owned affiliates, operating cash flows from our consolidated subsidiaries, public offerings of debt and equity, term loans and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flows. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

Our pipeline systems' principal sources of liquidity are cash generated from operating activities, long-term debt offerings, bank credit facilities and equity contributions from their owners. Our pipeline systems have historically funded operating expenses, debt service and cash distributions to their owners primarily with operating cash flow. However, since the fourth quarter of 2010, Great Lakes has funded its debt repayments with cash calls to its owners. Northern Border also funded $62 million of debt repayment in 2013 with a cash call to its owners.

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' owners. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends on their financial position and general market conditions.

The Partnership's pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs which, although limited by FERC, allow them to request credit support as circumstances dictate.

Our cash flow is based on the distributions from our portfolio of seven pipelines. Overall, we believe that our pipeline systems' ability to obtain financing at reasonable rates, together with a history of consistent cash flow from operating activities, provide a solid foundation to meet future liquidity and capital requirements. Over the next 12 months, we expect to be able to fund our liquidity requirements, including our distributions, at the Partnership level, utilizing our cash flow and our existing Senior Credit Facility if required.

Issuance of Class B Units to TransCanada

The Class B units issued on April 1, 2015 represent limited partner interests in us and entitle TransCanada to an annual distribution which is an amount based on 30 percent of GTN's annual distributions after achieving certain annual thresholds.

During the current year, we allocated a certain portion of our income to the Class B units representing the excess of 30 percent of GTN's distribution over the 2015 threshold level of $15 million. The allocated amount of $12 million was paid by the Partnership on February 12, 2016. See also Note 9 within Part IV, Item 15. "Exhibits and Financial Statements Schedules."

For 2016, the threshold level is $20 million and we expect such threshold will be exceeded in the third quarter of 2016. Our cash flows will continue to be impacted by distributions payable to the Class B units.

Please read Notes 6 and 7 within Part IV, Item 15. "Exhibits and Financial Statements Schedules" for more detailed disclosures on the 2015 GTN Acquisition and Issuance of Class B units.

EBITDA and Distributable Cash Flow

EBITDA is an approximate measure of our operating cash flow during the current earnings period and reconciles directly to the net income amount presented. It measures our earnings before deducting interest, depreciation and amortization and net income attributable to non-controlling interests, and it includes earnings from our equity investments.

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period and reconcile directly to the net income amount presented.

Total distributable cash flow includes EBITDA *plus:*

Distributions from our equity investments *less:*

Earnings from our equity investments,

Equity allowance for funds used during construction (Equity AFUDC),

Interest expense,

Distributions to non-controlling interests, and

Maintenance capital expenditures

Distributable cash flow is computed net of distributions declared to the General Partner and distributions allocable to Class B units. Distributions declared to the General Partner are based on its effective two percent interest plus an amount equal to incentive distributions. Distributions allocable to the Class B units equal 30 percent of GTN's distributable cash flow for the nine months ended December 31, 2015 less $15 million.

Distributable cash flow information and EBITDA are presented to assist investors in evaluating our business performance. We believe these measures provide additional meaningful information in evaluating our financial performance and 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.

The non-GAAP measures described above 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. Additionally, these measures as presented may not be comparable to similarly titled measures of other companies.

The following table represents a reconciliation of our EBITDA, Total distributable cash flow and distributable cash flow to the most directly comparable GAAP financial measure, Net income, for the periods presented:

Reconciliations of Net Income to EBITDA and Distributable Cash Flow

Year Ended December 31 *(millions of dollars)*	**2015**	2014	2013[(a)]
Net income	**20**	204	191
Add:			
Interest expense[(b)]	**60**	50	43
Depreciation and amortization[(c)]	**86**	87	87
Impairment of equity investment	**199**		
EBITDA	**365**	341	321
Add:			
Distributions from equity investments[(d)]			
Northern Border	**91**	88	84
Great Lakes	**40**	29	16
	131	117	100
Less:			
Equity earnings:			
Northern Border	**(66)**	(69)	(64)
Great Lakes	**(31)**	(19)	(3)
	(97)	(88)	(67)
Less:			
Equity AFUDC	**(1)**		
Interest expense[(b)]	**(60)**	(50)	(43)
Distributions to non-controlling interests[(e)]	**(11)**	(51)	(93)
Maintenance capital expenditures	**(16)**	(8)	(9)
Total Distributable Cash Flow[(f)]	**311**	261	209
General Partner distributions declared[(g)]	**(8)**	(5)	(4)
Distributions allocable to Class B units[(h)]	**(12)**		
Distributable Cash Flow[(f)]	**291**	256	205

(a)

Recast as discussed in Note 2 and Note 6 within Part IV, Item 15. "Exhibits and Financial Statement Schedules."

(b)

Interest expense as presented here includes net realized loss related to the interest rates swaps. Please read Notes 11 and 18 within Part IV, Item 15. "Exhibits and Financial Statements Schedules" for information.

(c)

Amounts presented here represent depreciation of Plant, property and equipment and Amortization of debt issuance costs. Please read Note 11 within Part IV, Item 15. "Exhibits and Financial Statements Schedules" for information.

(d)

Amounts here are calculated in accordance with the cash distribution policies of these entities. Distributions from each of our equity investments represent our respective share of these entities' quarterly distributable cash during the current reporting period.

(e)

Amounts here are calculated in accordance with the cash distribution policies of our consolidated subsidiaries. Distributions to non-controlling interests represent the respective share of quarterly distributable cash during the current reporting period not owned by us.

(f)

"Total Distributable Cash Flow" and "Distributable Cash Flow" represent the amount of distributable cash generated by the Partnership subsidiaries and equity investments during the current earnings period and thus reconcile directly to the net income amount presented.

The calculation differs from the previous non-GAAP measures "Partnership Cash Flows before General Partner distributions" and "Partnership Cash Flows" as the previously used measures primarily reflected cash received during the period through distributions from our subsidiaries and equity investments that were generated from the prior quarter's financial results. The amounts reflected here have been adjusted to reflect the calculation as described above and to present the comparable "Total Distributable Cash flow" and "Distributable Cash Flow" from the previous periods.

(g)

Distributions declared to the General Partner for the year ended December 31, 2015 included an incentive distribution of approximately $3 million (2014 $1 million).

(h)

During the nine months ended December 31, 2015, 30 percent of GTN's total distributions was $27 million; therefore the distributions allocable to the Class B units is $12 million, representing the amount that exceeded the threshold level of $15 million. The Class B distribution is determined and payable annually.

On January 21, 2016, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $12 million which was paid on February 12, 2016. Please read Notes 6, 9 and 12 within Part IV, Item 15. "Exhibits and Financial Statements Schedules" and Part II, Item 7. "Management Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Issuance of Class B Units to TransCanada."

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014

EBITDA increased by $24 million compared to the same period in 2014. The increase was primarily due to the net effect of:

- higher GTN revenue from the sale of short-term services;
- higher equity earnings from Great Lakes, mainly due to revenues related to contracts with affiliates;
- lower equity earnings from Northern Border, mainly due to lower revenues from the sale of short-term services as a result of the milder winter in 2015 compared to 2014; and
- lower expenses in the current period mainly due to lower spending on pipeline integrity work and lower property taxes.

Distributable cash flow increased by $35 million in the twelve months ended December 31, 2015 compared to the same period in 2014 primarily due to the net effect of:

- higher EBITDA;
- lower distributions to non-controlling interests as a result of the 2015 GTN Acquisition and the 2014 Bison Acquisition;
- higher maintenance capital expenditures primarily due to major compression equipment overhauls on GTN's pipeline system in 2015;
- higher interest expense related to additional borrowings to fund a portion of the 2014 Bison Acquisition and the 2015 GTN Acquisition;

- higher General Partner distributions due to higher IDRs in the current period; and

- distributions allocable to the Class B units during the current period.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

EBITDA increased by $20 million compared to the same period in 2013. The increase was primarily due to higher equity earnings from Great Lakes and Northern Border, mainly due to higher revenues from the sale of daily pipeline capacity as a result of colder winter weather in 2014 compared to 2013.

Distributable cash flow increased by $51 million in the twelve months ended December 31, 2014 compared to the same period in 2013 primarily due to the net effect of:

- higher EBITDA;

- lower distributions to non-controlling interests as a result of the 2013 Acquisition;

- higher interest expense related to additional borrowings to fund a portion of the 2013 Acquisitions and the 2014 Bison Acquisition

Other Cash Flows

On January 1, 2016, the Partnership acquired a 49.9 percent interest in PNGTS from a subsidiary of TransCanada. The total purchase price of the PNGTS Acquisition was $223 million plus preliminary purchase price adjustments of 3 million. The purchase price consisted of $191 million in cash (including the preliminary purchase price adjustment of $3 million) and the assumption of $35 million in proportional PNGTS debt. The Partnership funded the cash portion of the transaction using proceeds received from our ATM program and additional borrowings in our Senior Credit Facility. Refer to Note 22 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for additional disclosure regarding the PNGTS Acquisition.

In March and October of 2015, 2014 and 2013, the Partnership made equity contributions totaling $9 million in each year to Great Lakes to fund debt repayments.

On April 1, 2015, the Partnership acquired the remaining 30 percent interest in GTN from a subsidiary of TransCanada. The total purchase price of the 2015 GTN Acquisition was $446 million plus the final purchase price adjustment of $11 million, for a total of $457 million. The purchase price consisted of $264 million in cash (including the final purchase price adjustment of $11 million), the assumption of $98 million in proportional GTN debt and the issuance of 1,900,000 new Class B units to TransCanada valued at $50 each, representing a limited partner interest in the Partnership with a total value of $95 million. Refer to Note 6 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for additional disclosure regarding the 2015 GTN Acquisition.

On October 1, 2014, the Partnership acquired the remaining 30 percent interest in Bison from a subsidiary of TransCanada. The total purchase price of the 2014 Bison Acquisition was $215 million plus purchase price adjustments of approximately $2 million. The acquisition of Bison was financed through a combination of (i) net proceeds from the ATM Program, and (ii) short-term financing. Refer to Note 6 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for additional disclosure regarding the 2014 Bison Acquisition.

In the second quarter of 2014, the Partnership made a payment of $25 million in accordance with the 2013 Acquisition related to the attainment of certain events with respect to the Carty Lateral project.

In November 2013, the Partnership made an equity contribution totaling $31 million to Northern Border to fund the repayment of a portion of the Northern Border Credit Facility.

On July 1, 2013, the Partnership acquired a 45 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada, increasing the Partnership's ownership in each of GTN and Bison to 70 percent. The Partnership paid $921 million in respect of this acquisition in 2013. It was financed with net proceeds from an equity issuance of $373 million, borrowing of $500 million in term loans, an $8 million capital contribution from the General Partner, a draw under the Senior Credit Facility and cash on hand. Refer to Note 6 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for additional disclosure regarding the 2013 Acquisition.

In the second quarter of 2013, Bison's former parent made an equity contribution to Bison of $18 million which was used to repay inter-affiliate debt primarily related to pipeline construction costs, including reclamation and restoration work.

Contractual Obligations

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2015 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 2017	200		200		
2013 Term Loan Facility due 2018	500		500		
2015 Term Loan Facility due 2018	170		170		
4.65% Senior Notes due 2021	350				350
4.375% Senior Notes due 2025	349				349
5.29% Senior Notes due 2020	100			100	
5.69% Senior Notes due 2035	150				150
Unsecured Term Loan Facility due 2019	75	10	30	35	
3.82% Series D Senior Notes due 2017	16	4	12		
Interest on Debt Obligations[(a)]	633	66	127	198	242
Operating Leases	5	1	1	1	2
	2,548	81	1,040	334	1,093

(a)
Interest payments on floating-rate debt are estimated using interest rates effective as of December 31, 2015.

The Partnership's Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, maturing November 20, 2017, under which $200 million was outstanding at December 31, 2015 (2014 $330 million).

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be lenders' base rate or 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 Credit Facility. The Senior 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 Credit Facility of up to $250 million, but no lender has an obligation to increase their respective share of the facility.

The LIBOR-based interest rate on the Senior Credit Facility averaged 1.44 percent for the year ended December 31, 2015 (2014 1.41 percent).

On July 1, 2013, the Partnership entered into a term loan agreement with a syndicate of lenders for a $500 million Term Loan Facility (2013 Term Loan Facility). On July 2, 2013, the Partnership borrowed $500 million under the 2013 Term Loan Facility, which matures on July 1, 2018. The outstanding principal amount bears interest based, at the Partnership's election, on the LIBOR or the base rate plus, in either case, an applicable margin.

The LIBOR based interest rate on the Term Loan Facility averaged 1.44 percent for the year ended December 31, 2015. After hedging activity, the interest rate incurred on the Term Loan Facility averaged 1.85 percent for the year ended December 31, 2015. Prior to hedging activities, the LIBOR-based interest rate was 1.50 percent at December 31, 2015 (2014-1.41 percent).

On September 30, 2015, the Partnership entered into an agreement for a $170 million term loan credit facility (2015 Term Loan Facility). The Partnership borrowed $170 million under the 2015 Term Loan Facility to refinance its

Short-Term Loan Facility which matured on September 30, 2015. The 2015 Term Loan Facility matures on October 1, 2018. The LIBOR-based interest rate on the 2015 Term Loan Facility was 1.39 percent at December 31, 2015.

The 2013 Term Loan Facility and the 2015 Term Loan Facility (Term Loan Facilities) and the Senior Credit Facility require the Partnership to maintain a certain 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]). In the quarter in which an acquisition has occurred, and the two quarters following the acquisition, the allowable leverage ratio increases to 5.50 to 1.00. Thereafter, the ratio returns to 5.00 to 1.00. The allowable ratio for the quarter ended December 31, 2015 was 5.50 to 1.00. The leverage ratio was 4.68 to 1.00 as of December 31, 2015. The Senior Credit Facility and the Term Loan Facilities contain 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 and the Term Loan Facilities may become immediately due and payable.

On March 13, 2015, the Partnership closed a $350 million public offering of senior unsecured notes bearing an interest rate of 4.375 percent maturing March 13, 2025. The net proceeds of $346 million were used to fund a portion of the acquisition of the remaining 30 percent interest in GTN (refer to Note 6 within Part IV, Item 15) and to reduce the amount outstanding under our Senior Credit Facility. The indenture for the notes contains customary investment grade covenants.

On June 1, 2015, GTN's 5.09 percent unsecured Senior Notes matured. Also, on June 1, 2015, GTN entered into a $75 million unsecured variable rate term loan facility (Unsecured Term Loan Facility), which requires yearly principal payments until its maturity on June 1, 2019. The variable interest is based on LIBOR plus an applicable margin. The LIBOR-based interest rate on the Unsecured Term Loan Facility for the year ended December 31, 2015 averaged 1.16 percent and was 1.15 percent at December 31, 2015. GTN's Unsecured Senior Notes, along with this new Unsecured Term Loan Facility contain a covenant that limits total debt to no greater than 70 percent of GTN's total capitalization. GTN's total debt to total capitalization ratio at December 31, 2015 was 43.8 percent.

The Series 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.

At December 31, 2015, the Partnership was in compliance with its financial covenants.

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, 2015 was $1,873 million. As of February 26, 2016, the Partnership had $365 million outstanding under the Senior Credit Facility.

Capital Requirements

The Partnership is expected to make equity contributions totaling $9 million to Great Lakes in 2016 for scheduled debt repayments.

The Partnership's equity investee Northern Border has $100 million of senior notes due in August 2016. This amount will be refinanced with a combination of debt and/or equity at the discretion of the management committee. If an equity contribution is elected to repay the senior notes, the Partnership will be expected to make an equity contribution of up to $50 million to Northern Border.

In the fourth quarter of 2015, the Carty Lateral project went in service and the Partnership expects to spend approximately $3 million to close out construction expenditures on this project in 2016.

We expect to be able to fund our capital requirements over the next 12 months utilizing operating cash flow, equity issuances and when required, debt, including our existing Senior Credit Facility.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2015 included the following:

		Payments Due by Period[a]			
(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	100			
7.50% Senior Notes due 2021	250			250	
$200 million Credit Agreement due 2020	61			61	
Interest payments on debt	125	26	64	35	
Operating leases	55	2	6	5	42
Other long-term obligations	5	5			
	596	133	70	351	42

(a) Represents 100 percent of Northern Border's contractual obligations.

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 for the notes do not limit the amount of unsecured debt Northern Border may incur, but do restrict secured indebtedness. At December 31, 2015, Northern Border was in compliance with all of its financial covenants.

At December 31, 2015, the aggregate estimated fair value of Northern Border's long-term debt was approximately $426 million (2014 $476 million). In 2015, interest expense related to the senior notes was $25 million (2014 $25 million; 2013 $25 million).

Credit Agreement

Northern Border's credit agreement consists of a $200 million revolving credit facility. On October 9, 2015 Northern Border's credit facility was renewed and extended for an additional five years maturing on October 9, 2020. At December 31, 2015, $61 million was outstanding leaving $139 million available for future borrowings. At Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or LIBOR plus, in either case, an applicable margin that is based on Northern Border's long-term unsecured credit ratings. The interest rate on Northern Border's credit agreement at December 31, 2015 was 1.74 percent (2014 1.39 percent). At December 31, 2015, Northern Border was in compliance with all of its financial covenants.

Operating Leases

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

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations as of December 31, 2015 included the following:

		Payments Due by Period[a]			
(millions of dollars)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.73% series Senior Notes due 2016 to 2018	27	9	18		
9.09% series Senior Notes due 2016 to 2021	60	10	20	20	10
6.95% series Senior Notes due 2019 to 2028	110			22	88
8.08% series Senior Notes due 2021 to 2030	100				100
Interest payments on debt	164	23	41	34	66
	461	42	79	76	264

(a) Represents 100 percent of Great Lakes' contractual obligations.

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 $160 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2015 (2014 $170 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2015.

The aggregate estimated fair value of Great Lakes' long-term debt was $362 million at December 31, 2015 (2014 $409 million). The aggregate annual required repayment of senior notes is $19 million for each year 2016 through 2018 and $21 million for each year 2019 and 2020. Aggregate required repayments of senior notes thereafter total $198 million. In 2015, interest expense related to Great Lakes' senior notes was $24 million (2014 $25 million; 2013 $27 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.

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 effective two percent general partner interest, represents the IDRs.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distribution	
		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%

2015 Fourth Quarter Cash Distribution

On January 21, 2016, the board of directors of our General Partner declared the Partnership's fourth quarter 2015 cash distribution in the amount of $0.89 per common unit. The fourth quarter cash distribution, which was paid on February 12, 2016 to unitholders of record as of February 2, 2016, totaled $59 million and was paid in the following manner: $57 million to common unitholders (including $5 million to the General Partner as holder of 5,797,106 common units and $10 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $2 million to the General Partner in respect of its two percent general partner interest and incentive distributions.

For the year ending December 31, 2015, the total cash distribution declared by the board of directors of our General Partner was $3.51 per common unit.

Please read Note 13, which provides a summary information schedule regarding our distributions within Part IV, Item 15. "Exhibits and Financial Statements Schedules".

Distributions to Class B Units

The Class B units issued on April 1, 2015 represent limited partner interests in us and entitle TransCanada to an annual distribution which is an amount based on 30 percent of GTN's annual distributions after achieving certain annual thresholds.

During the current year, such threshold was exceeded. As a result, on January 21, 2016, the board of directors of our General Partner declared distributions to the Class B unitholders in the amount of $12 million which amount was paid on February 12, 2016.

Please read Notes 6, 9 and 12 within Part IV, Item 15. "Exhibits and Financial Statements Schedules" and Part II, Item 7. "Management Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Issuance of Class B Units to TransCanada."

Distribution Policies of Our Pipeline Systems

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. Our pipeline systems' respective management committees determine the amounts and timing of cash distributions, where the amounts of such distributions are based on distributable cash flow as determined by a prescribed formula. Any changes to, or suspension of our pipeline systems' cash distribution policies requires the unanimous approval of their respective management committees.

GTN, Bison, and North Baja's distribution policies require the pipelines to distribute 100 percent of distributable cash flow based on earnings before depreciation and amortization less allowance for funds used during construction (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.

Tuscarora's distribution policy requires the distribution of 100 percent of distributable cash flow based on earnings before depreciation and amortization less debt repayment, 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.

Northern Border's distribution policy requires Northern Border 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. Northern Border adopted certain changes related to equity contributions that 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.

Great Lakes' distribution policy requires the distribution of 100 percent of distributable cash flow based on earnings before income taxes, depreciation, AFUDC less capital expenditures and debt repayments not funded with cash calls to its partners. This defined formula is subject to management committee approval and can be modified to ensure minimum cash balances, equity balances and ratios are maintained.

PNGTS distributes its available cash less any required reserves that are necessary to comply with its debt covenants and/or appropriately conduct its business, as determined and approved by its management committee.

Cash from Our Pipeline Systems

Northern Border declared its fourth quarter 2015 distribution of $44 million on January 11, 2016, of which the Partnership received its 50 percent share or $22 million. The distribution was paid on February 1, 2016.

Great Lakes declared its fourth quarter 2015 distribution of $42 million on January 11, 2016, of which the Partnership received its 46.45 percent share or $20 million. The distribution was paid on February 1, 2016.

The Partnership's equity investee PNGTS has $22 million of senior secured notes due in 2016, of which the Partnership's share is approximately $11 million. While PNGTS debt repayments are not funded with cash calls to its owners, PNGTS has historically funded its scheduled debt repayments by adjusting its available cash for distribution, which effectively reduces the net cash that will be received by the Partnership as distributions from PNGTS.

Investing Activities for our Pipeline Systems

The Partnership's share in capital spending for maintenance of existing facilities and growth projects was as follows:

Year Ended December 31 *(millions of dollars)*	**2015**	2014	2013[(a)]
Maintenance	**21**	18	22
Growth	**54**	4	3
	75	22	25

(a) Recast as discussed in Note 2 and Note 6 of the Partnership's consolidated financial statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules" of this report.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014

Overall capital spending increased by $53 million mainly due to the cost incurred on the construction of Carty Lateral which was placed in service in October 2015.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

Maintenance capital spending decreased $4 million primarily due to a 2013 major compression equipment overhaul on GTN's pipeline system.

Other Investing Activities

In 2016, our pipeline systems expect to invest approximately $48 million in maintenance of existing facilities and approximately $15 million in growth projects, of which the Partnership's share would be $33 million and $10 million, respectively.

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.

We believe our critical accounting estimates discussed in the following paragraphs require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. These critical accounting estimates should be read in conjunction with Note 2 of Part IV, Item 15. "Exhibits and Financial Statement Schedules."

We account for our investments in Northern Border and Great Lakes 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 Northern Border and Great Lakes because of our ownership interests and our representation on their management committees.

We account for our investments in GTN, Bison, North Baja and Tuscarora using the consolidation method, as we are able to exercise control over these investments because of our ownership interests and our representation on their management committees.

Regulation

Our pipeline systems' accounting policies conform to *Accounting Standards Codification (ASC) 980 Regulated Operations*. As a result, our pipeline systems record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. 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 pipeline 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 pipeline systems would be required to write off the regulatory assets at that time.

As of December 31, 2015, Northern Border reflected regulatory assets of $16 million on its balance sheet (2014 $32 million). Northern Border also has regulatory liabilities of $22 million as of December 31, 2015 (2014 $20 million).

As of December 31, 2015 and 2014, Great Lakes did not have any material regulatory assets and no material regulatory liabilities recorded on its balance sheet.

At December 31, 2015, the Partnership had $2 million regulatory assets reported as part of accounts receivable and other in the balance sheet representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers continually (2014   nil). As of December 31, 2015, the Partnership had regulatory liabilities of $24 million mostly relating to estimated costs associated with future removal of transmission and gathering facilities or allowed to be collected by FERC in depreciation rates (2014 $23 million).

Impairment of Equity Investments, Goodwill and Long-Lived Assets

Equity Investments

We review our equity method investments when a significant event or change in circumstances has occurred that may have an adverse effect on the fair value of each investment. When such events or changes occur, we compare the estimated fair value to the carrying value of the related investment. We calculate the estimated fair value of an investment in an equity method investee using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows, which is dependent on internal forecasts, estimates of the long-term rate of growth for the investee, estimates of the useful life over which cash flows will occur, and determination of weighted average cost of capital. The estimates used to calculate the fair value of an investee can change from year to year based on operating results and market conditions. Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether an investment in an equity method investee has suffered impairment.

If the estimated fair value of an investment is less than its carrying value, we are required to determine if the decline in fair value is other than temporary. This determination considers the aforementioned valuation methodologies, the length of time and the extent to which fair value has been less than carrying value, the financial condition and near-term prospects of the investee, including any specific events which may influence the operations of the investee, the intent and ability of the holder to retain its investment in the investee for a period of time sufficient to allow for any anticipated recovery in market value, and other facts and circumstances. If the fair value of an investment is less than its carrying value and the decline in value is determined to be other than temporary, we record an impairment charge.

As of December 31, 2015, no impairment charge has been recorded related to our equity investment in Northern Border. However, if our assumptions change significantly, our requirement to record an impairment charge could change.

Despite the recent improvement in income from our investment in Great Lakes since 2013, including favorable current year results, its long-term value has been adversely impacted by the changing natural gas flows in its market region as well as our conclusion in the fourth quarter that other strategic alternatives to increase its utilization or revenue were no longer feasible. As a result, we determined that the carrying value of our investment in Great Lakes was in excess of its fair value and the decline is not temporary. Accordingly, we concluded that the carrying value of our investment in Great Lakes was impaired.

Our analysis determined that the fair value of our investment in Great Lakes is $465 million, resulting in an impairment charge of $199 million in the fourth quarter of 2015, reflected as Impairment of equity-method investment on our Statement of Income for the year ended December 31, 2015.

Our assumptions related to the estimated fair value of our remaining equity investment in Great Lakes could be negatively impacted by near and long-term conditions including:

- future regulatory rate action or settlement,
- valuation of Great lakes in future transactions,
- changes in customer demand at Great Lakes for pipeline capacity and services,
- changes in North American natural gas production in the major producing basins,
- changes in natural gas prices and natural gas storage market conditions, and
- changes in other long-term strategic objectives.

There is a risk that adverse changes in these key assumptions could result in additional future impairment of the carrying value of our investment in Great Lakes.

Goodwill

We test goodwill for impairment annually based on *ASC 350 Intangibles Goodwill and Other*, or more frequently if events or changes in circumstances lead us to believe it might be impaired. We assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we do not conclude that it is more likely than not that the fair value of the reporting unit is greater than the carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit, including its goodwill, to its book value. If the fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value calculated in the first step. If the goodwill's carrying value exceeds its implied fair value we record an impairment charge.

We base these valuations on our projection of future cash flows which involves making estimates and assumptions about:

- discount rates;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies;
- regulatory changes; and
- regulatory rate action or settlement.

If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of reporting unit, to the extent of the balance of goodwill.

At December 31, 2015 and 2014, we had $130 million of goodwill recorded on our consolidated balance sheet related to the North Baja and Tuscarora acquisitions. No impairment of goodwill existed at December 31, 2015.

Long-Lived Assets

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 charge 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.

Our management evaluates changes in our business and economic conditions and their implications for recoverability of our long-lived assets' carrying values when assessing these assets for impairments. The development of fair value estimates requires significant judgement in estimating future cash flows, In order to determine the estimated future cash flows, management must make certain estimates and assumptions, which include, but are not limited to, demand, competition, contract renewals and other factors.

Any changes we make to these estimates and assumptions could materially affect future cash flows, which could result to the recognition of an impairment loss in our statement of income.

As of December 31, 2015, there were no indicators of impairment for our long-lived assets.

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.

CONTINGENCIES

Legal

Various legal actions or governmental proceedings involving our pipeline systems 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 Part I, Item 3. "Legal Proceedings" for additional information.

Environmental

We do not believe that compliance with existing environmental laws and regulations will have a material adverse effect on our pipeline systems. Because of the inherent uncertainties as to the final outcome of proposed environmental regulations and legislation, we cannot estimate the range of possible costs, if any, from the proposals. Please read Part I, Item 1. "Business Government Regulation" for additional information.

Greenhouse Gas Regulation

Through the EPA, the U.S. Government has imposed various measures related to GHG emissions, including emission monitoring and reporting requirements, preconstruction and operating permits for certain large stationary sources. The EPA has also proposed rules requiring the control of methane emissions from and leak detection and repair requirements for certain oil and natural gas production, processing, transmission and storage activities, as well as leak detection and repair requirements. These final and proposed rules, as well as additional legislation or regulations for the control of GHG emissions 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. The regulation or restriction of GHG emissions could also result in changes to the consumption and demand for natural gas. This could have either positive or adverse effects on our pipeline systems, our financial position, results of operations and future prospects.

RELATED PARTY TRANSACTIONS

Please read Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" and Note 16 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more information regarding related party transactions.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

The Partnership and our pipeline systems are exposed to market risk, counterparty credit risk and liquidity risk. 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.

Our primary risk management objective is to mitigate the impact of these risks on 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

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.

Market risk is the risk that changes in market interest rates may result in fluctuations in the fair values or cash flows of financial instruments. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

As of December 31, 2015, the Partnership's interest rate exposure results from our floating rate Senior Credit Facility, the unhedged portion of our 2013 Term Loan Facility, our 2015 Term Loan Facility and GTN's Unsecured Term Facility, under which $795 million, or 42 percent, of our outstanding debt was subject to variability in LIBOR interest rates. As of December 31, 2014, the Partnership's interest rate exposure results from our floating rate Senior Credit Facility, the unhedged portion of our 2013 Term Loan Facility and our Short-Term Loan Facility, under which $850 million, or 50 percent, of our outstanding debt was subject to variability in LIBOR interest rates.

As of December 31, 2015, the variable interest rate exposure related to $150 million of the $500 million 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements. If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2015, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately $8 million.

As of December 31, 2015, $61 million, or 15 percent of Northern Border's outstanding debt was at floating rates (2014 $61 million or 15 percent). If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2015, Northern Border's annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately $1 million.

GTN's Unsecured Senior Notes, Northern Border's Senior Notes, and all of Great Lakes' and Tuscarora's notes represent 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.

The Partnership and our pipeline systems use derivatives as part of our overall risk management policy to assist in managing 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.

- 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 interest rate swaps and option agreements to mitigate the impact of changes in interest rates.

The Partnership hedged interest payments on $150 million of variable-rate 2013 Term Loan Facility with interest rate swaps effective September 3, 2013 and maturing July 1, 2018, at a weighted average fixed interest rate of 2.79 percent. At December 31, 2015 and 2014, the fair value of the interest rate swaps accounted for as cash flow hedges was a liability of $1 million (both on a gross and net basis) (December 31, 2013 less than $1 million). In 2015, the Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges. The change in fair value of interest rate derivative instruments recognized in other comprehensive income was nil million for the year ended December 31, 2015 (2014 $1 million; 2013 less than $1 million). In 2015, the net realized loss related to the interest rate swaps was $2 million and was included in financial charges and other (2014 $2 million; 2013 $1 million).

On January 25, 2016, the Partnership hedged interest payments on the remaining $350 million of the $500 million variable-rate 2013 Term Loan Facility with interest rate swaps from January 27, 2016 through July 1, 2018, where the weighted average fixed rate paid is 2.10 percent.

The Partnership has no master netting agreements, however, contracts contain provisions with rights of offset. The Partnership has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the balance sheet. Had the Partnership elected to present these instruments on a net basis, there would be no effect on the consolidated balance sheet as of December 31, 2015 and 2014.

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 AND LIQUIDITY RISK

Counterparty credit risk represents the financial loss that the Partnership and our pipeline systems would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Partnership or its pipeline systems. 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 customers. The Partnership closely monitors the creditworthiness of our counterparties, including financial institutions. However, we cannot predict to what extent our business would be impacted by uncertainty in energy commodity prices, including possible declines in our customers' credit worthiness.

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. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 31, 2015, we had no derivative financial assets and we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2015, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $35 million and two of our customers, Anadarko Energy Services Company, and Pacific Gas and Electric Company, owed us approximately $4 million and $3 million, respectively, which represented greater than 10 percent of our trade accounts receivable.

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, 2015, the Partnership had a Senior Credit Facility of $500 million maturing in 2017 and the outstanding balance on this facility was $200 million. In addition, at December 31, 2015, Northern Border had a committed revolving bank line of $200 million maturing in 2020 and $61 million was drawn. Both the Senior Credit Facility and the Northern Border credit facility have accordion features for additional capacity of $250 million and $100 million respectively, subject to lender consent.

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, 2015, there was no change in the Partnership's internal control over financial reporting that has materially impacted or is reasonably likely to materially impact 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 in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment according to the above framework, management has concluded that our internal control over financial reporting was effective as of December 31, 2015 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-2 of the financial statements included in this Form 10-K.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The Partnership is a limited partnership and as such has no officers, directors or employees. Set forth below is certain information concerning the directors and officers of the General Partner who manage the operations of the Partnership. Each director holds office for a one-year term or until his or her successor is earlier appointed. All officers of the General Partner serve at the discretion of the board of directors of the General Partner which is an indirect wholly-owned subsidiary of TransCanada.

Name	Age	Position with General Partner
Karl Johannson	55	Chair and Director
Jack F. Stark	65	Independent Director
Malyn K. Malquist	63	Independent Director
Walentin (Val) Mirosh	70	Independent Director
Brandon M. Anderson	43	President, Principal Executive Officer and Director
M. Catharine Davis	51	Director
Joel E. Hunter	49	Director
Janine M. Watson	46	Vice-President and General Manager
Nathaniel A. Brown	39	Controller, Principal Financial Officer
Terry C. Ofremchuk	65	Vice-President, Taxation
Jon A. Dobson	49	Secretary
William C. Morris	53	Treasurer

Mr. Johannson was appointed a director and Chair of the Board of Directors of the General Partner in March 2013. Mr. Johannson's principal occupation is Executive Vice-President and President, Natural Gas Pipelines for TransCanada. He is accountable for TransCanada's natural gas pipelines and regulated natural gas storage business in Canada, the U.S. and Mexico. Prior to November 2012, Mr. Johannson was Senior Vice-President, Canadian and Eastern U.S. Pipelines, a position he has held since January 2011. From January 2006 to December 2010, he held the position of Senior Vice-President, Canadian Power, where he was responsible for all activities relating to the day-to-day commercial management of TransCanada's Canadian power business. Mr. Johannson has extensive senior management experience in the pipelines and energy industries as a result of his service as an executive of TransCanada and its affiliates. His experience in his prior roles at TransCanada provides him with intimate knowledge of the Partnership, including its strategies, operations and markets. Mr. Johannson's industry knowledge, management experience and leadership skills are highly valuable in assessing our business strategies and accompanying risks.

Mr. Stark was appointed a director of the General Partner in July 1999. Mr. Stark's principal occupation is Chief Financial Officer of Imergy Power Systems, formerly Deeya Energy, an energy storage systems company. Mr. Stark was Chief Financial Officer of BrightSource Energy Inc., a provider of technology for use in large-scale solar thermal power plans from May 2007 to November 2013. Mr. 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. Mr. Stark is also director of TerraForm Power, Inc. and TerraForm Global, Inc. Through his current and prior roles as chief financial officer of numerous companies, Mr. 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. 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 of 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 provides products, technologies and services in the light building products, heavy construction materials and energy industries. 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 Directors.

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. Anderson was appointed President, Principal Executive Officer and a Director of the General Partner in January 2016. Mr. Anderson also holds the position of Senior Vice-President and General Manager, U.S. Natural Gas pipelines for TransCanada, a position he has held since July 2015. Mr. Anderson has over 20 years of energy industry experience and, since joining TransCanada in 2002, has held a variety of leadership positions in energy marketing and trading, business development, electricity, gas storage and TransCanada's Mexico pipeline operations. Mr. Anderson served as Senior Vice President and General Manager, Mexico Gas and Power from May 2013 to July 2015, Senior Vice President, Western Power and Gas Storage from January 2011 to May 2013 and Vice President, Gas Storage from March 2006 to January 2011.

Ms. Davis was appointed a director of the General Partner in April 2014. Ms. Davis' principal occupation is Vice-President, Law, Natural Gas Pipelines for TransCanada. Ms. Davis is responsible for the regulatory, compliance, commercial, safety, environment, and business development law services provided to TransCanada's existing and proposed natural gas pipelines in Canada, the U.S., and Mexico. She is Chief Compliance Officer for the TransCanada Mainline and NGTL systems. From November of 2012 to October of 2015, Ms. Davis was the Vice-President, Law, Canadian Pipelines, Corporate Services Division for TransCanada, responsible for the regulatory, commercial, Aboriginal, land, safety, and environment law services provided to TransCanada's existing and proposed oil pipelines both in Canada and the U.S., and to its existing and proposed Canadian natural gas pipelines. From February 2007 to November 2012, Ms. Davis was Chief Compliance Officer and Associate General Counsel, and later Vice President, U.S. Pipelines Law for TransCanada's U.S. natural gas pipelines and storage companies. Prior to joining TransCanada in February 2007, Ms. Davis held various legal positions at Great Lakes Gas Transmission Company, most recently as Associate General Counsel and Chief Compliance Officer. Prior to 1992, she worked in the Federal Energy Regulatory Commission's Office of Administrative Law Judges, as a law clerk.

Mr. Hunter was appointed a director of the General Partner in April 2014. Mr. Hunter's principal occupation is the Vice-President, Finance, and Treasurer, for TransCanada, and is responsible for Corporate Finance, Corporate Planning, Trading and Financial Risk Management, Cash Management and Pension Asset Management. Since joining TransCanada in 1997, Mr. Hunter has held a number of positions of increasing responsibility, including Director of Corporate Finance from January 2008 to July 2010.

Ms. Watson was appointed Vice-President and General Manager for the General Partner in October 2015. Her principal occupation is Director, LP Management & Pricing for TransCanada, a position she has held since October 2015. Ms. Watson has served in progressively senior positions in the natural gas pipeline and energy business segments of

TransCanada since 1997. Prior to joining TransCanada, Ms. Watson was an attorney at the Calgary office of McCarthy T étrault and clerked at the Alberta Court of Appeal.

Mr. Brown was appointed the Controller and Principal Financial Officer of the General Partner in May 2014. His principal occupation is Director of Financial Services for TransCanada's U.S. Pipelines. In that capacity, Mr. Brown is responsible for accounting, financial reporting, planning and budgeting. Previously, Mr. Brown was Manager of accounting for TransCanada's U.S. Pipelines West from November 2009 through May 2014. In this role, he also provides regulatory accounting support for rate filings, settlement negotiations, and other regulatory proceedings. Prior to joining TransCanada, Mr. Brown spent eight years in public accounting, most recently as an audit manager for Grant Thornton LLP and Ernst & Young.

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.

Mr. Dobson was appointed Secretary of the General Partner in May 2014, prior to which he served as Assistant Secretary of the General Partner since April 2012. Mr. Dobson's principal occupation is Director, U.S., Governance, and Corporate and Securities Law and Corporate Secretary for TransCanada's U.S. subsidiaries. Prior to joining TransCanada in January 2011, Mr. Dobson spent 18 years practicing law in various corporate and law firm positions, including Vice President and Assistant General Counsel of Nash Finch Company; Vice President, General Counsel and Secretary of BMC Industries, Inc.; and associate attorney at Lindquist & Vennum, PLLP.

Mr. Morris was appointed Treasurer of the General Partner in December 2012. Mr. Morris' principal occupation is Director, Finance and Assistant Treasurer of TransCanada, a position he has held since November 2015, and previous to that as Director, Corporate Finance since November 2012. From 2001 to 2012, Mr. Morris was Director of Risk Management for TransCanada and Manager, Risk Management for TransCanada for the previous five years. Prior to joining TransCanada, Mr. Morris spent 12 years in both the public accounting and banking industries.

GOVERNANCE MATTERS

We are a limited partnership and a 'controlled company' as that term is used in NYSE Rule 303A.00, because all of our voting shares are owned by the General Partner. As such, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

The NYSE listing standards require our principal executive officer to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. This certification was provided to the NYSE on March 27, 2015.

AUDIT COMMITTEE FINANCIAL EXPERT

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

CODE OF ETHICS AND CORPORATE GOVERNANCE GUIDELINES

The Partnership believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. The directors, officers, employees and contractors of the General Partner are subject to TransCanada's Code of Business Ethics (COBE), which also has been adopted for the Partnership by our General Partner. Our COBE is published on our website at www.transcanada.com. If any substantive amendments are made to the COBE 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.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how our Board of Directors should function and its position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at www.tcpipelineslp.com. If any amendments are made to the Corporate Governance Guidelines, the amendment will be published on the Partnership's website or filed in a report on Form 8-K.

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 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.

The Audit Committee has adopted a charter which specifically provides that it is responsible for the appointment, compensation, retention and oversight of the independent public accountants engaged in preparing and 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 of 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.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of the General Partner meet at regularly scheduled executive sessions without management. Jack Stark serves as the presiding director at those executive sessions. Persons wishing to communicate with the General Partner's independent directors may do so by writing in care of Secretary, Board of Directors, TC PipeLines, GP, Inc., 700 Louisiana Street, Suite 700, Houston, TX 77002, or via fax at 1.508.871.7047.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, as amended, requires the General Partner'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 2015.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and 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 Information Circular" on the TransCanada website at www.tcpipelineslp.com. The TransCanada "Management Information Circular" is prepared by TransCanada pursuant to applicable 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. We are allocated and reimburse TransCanada for a percentage of the compensation, including base salary and certain benefit and incentive compensation expenses related to the officers of our General Partner and employees of TransCanada who perform services on our behalf. The base salaries that are allocable to us vary for each officer or employee 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. The Board of Directors of our General Partner specifically approves the percentage allocation to the Partnership of the compensation of the executive officers of the General Partner on an annual basis. Please read Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" for more information regarding this arrangement.

The following table summarizes the salary allocated to, and paid by, us in 2015, 2014 and 2013 for our President and Principal Executive Officer, Controller and 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)]**	**Approximate Percentage of Time Devoted to the Partnership**	**Total Compensation**
Steven D. Becker[(e)]	**2015**	**56,400**	**14,664**	**31,020**	**30%**	**102,084**
President and Principal	2014	64,091	18,586	35,250	30%	117,927
Executive Officer	2013	70,250	20,373	38,638	30%	129,261
Nathan A. Brown[(d)]	**2015**	**56,765**	**26,112**	**31,221**	**35%**	**114,098**
Controller and Principal	2014	45,514	20,936	25,033	35%	91,483
Financial Officer						

Jon A. Dobson Secretary	**2015**	**103,508**	**47,614**	**56,929**	**50%**	**208,051**
Terry C. Ofremchuk[(e)] Vice-President, Taxation	**2015** 2014 2013	**74,517** 83,644 89,420	**19,374** 24,257 25,932	**40,984** 46,004 49,181	**45%** 45% 45%	**134,875** 153,905 164,533
William C. Morris[(e)] Treasurer	**2015** 2014 2013	**89,990** 90,765 97,992	**23,397** 26,322 28,418	**49,494** 49,921 53,896	**50%** 45% 45%	**162,881** 167,008 180,306

(a) We reimburse TransCanada 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 benefit reimbursement is determined monthly and calculated based on total monthly base salary allocated to us multiplied by a factor applicable to benefits of US and Canadian employees.

(c) The incentive compensation reimbursement is determined monthly and calculated based on total monthly salary allocated to us multiplied by a factor of 0.55 for incentive compensation in 2015, 2014 and 2013.

(d) Appointed as Principal Financial Officer and Controller in May 2014. 2014 figures for Mr. Brown relates to the period from May 2014 to December 2014.

(e) Amounts presented have been converted to U.S. Dollars from Canadian dollars using the average exchange rate for the applicable year.

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:

Brandon Anderson
M. Catharine Davis
Joel E. Hunter
Karl R. Johannson
Malyn K. Malquist
Walentin (Val) Mirosh
Jack F. Stark

Independent Director Compensation[(a)]

For the year ended December 31, 2015 *(in dollars)*	Earned or Paid in Cash	Unit Awards[(b)]	Total
Malyn K. Malquist	105,500	60,000	160,500
Jack F. Stark[(c)]	100,500	60,000	150,500
Walentin (Val) Mirosh	90,500	60,000	165,500

(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 Karl R. Johannson, Steven D. Becker, M. Catharine Davis and Joel E. Hunter. 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) Amounts presented reflect the compensation expense recognized related to the DSUs granted during 2015 under the DSU Plan. All of the DSUs granted to Mr. Malquist, Mr. Stark and Mr. Mirosh were outstanding at December 31, 2015.

At December 31, 2015, Mr. Malquist, Mr. Stark and Mr. Mirosh held 7,093, 15,408 and 9,674 DSUs, respectively. The fair market value of the DSUs held by Mr. Malquist, Mr. Stark and Mr. Mirosh at December 31, 2015 was $352,572, $765,953 and $480,888, respectively. Amounts also include amounts credited to each independent director's DSU account equal to the distributions payable on the DSUs previously granted or credited. In this regard, Mr. Malquist was credited 364 DSUs, Mr. Stark was credited 837 DSUs and Mr. Mirosh was credited 511 DSUs. All DSUs credited during 2015 were outstanding at December 31, 2015.

(c) Lead Independent Director and Chair of the Conflicts Committee.

Cash Compensation

In 2015, 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 $110,000 per annum, of which $60,000 was automatically granted in DSUs (see DSUs section below). The independent director appointed as Lead Independent 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 $10,000 and $15,000 per annum, respectively. 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 DSU Plan. On November 5, 2015, the board approved an increase in the independent directors' 2016 annual retainer fee of $10,000 per annum, of which $5,000 will be granted in DSUs. As a result, commencing January 1, 2016, the retainer fee is $120,000 per annum, of which $65,000 is automatically be granted in DSUs.

Deferred Share Units

The DSU Plan was established in 2007 with the first grant occurring in January 2008. In 2015, as part of the retainer fee, each independent director received an automatic grant of DSUs with a value of $60,000, which was paid quarterly. Commencing January 1, 2016, the retainer fee increased $120,000 per annum, of which $65,000 is automatically granted in DSUs.

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 15, 2016 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 five percent of our common units.

	Amount and Nature of Beneficial Ownership			
	TC Pipelines, LP		TransCanada Corporation	
Name and Business Address	**Number of Units[(a)]**	**Per cent of Class[(b)]**	**Common Shares**	**Per cent of class**
TransCan Northern Ltd[(c)] 450-1st Street SW Calgary, Alberta T2P 5H1	11,287,725	17.6		
TC Pipelines GP, Inc.[(d)] 450-1st Street SW Calgary, Alberta T2P 5H1	5,797,106	9.0		
OppenheimerFunds, Inc.[(e)] Two World Financial Center 225 Liberty Street New York, NY 10281	9,395,607	14.61		
Center Coast Capital Advisors, LP[(f)] 1600 Smith Street, Suite 3800 Houston, TX 77002	3,331,338	5.2		
ALPS Advisors, Inc.[(g)] 1290 Broadway, Suite 1100 Denver, CO 80203	3,650,030	5.7		
Malyn K. Malquist[(h)]	8,254	*		
Jack F. Stark[(i)]	16,474	*		
Walentin (Val) Mirosh[(j)]	9,894	*	995	*
Karl R. Johannson[(k)]			378,770	*
Steven D. Becker[(l)]			93,530	*
M. Catharine Davis[(m)]			26,668	*
Joel E. Hunter[(n)]			50,045	*
Nathaniel A. Brown				*
Jon A. Dobson[(o)]			372	*

	Amount and Nature of Beneficial Ownership			
Terry C. Ofremchuk[p]			9,250	*
William C. Morris[q]			16,068	*
Janine M. Watson[r]			2,078	
Directors and Executive officers as a Group[s] (13 people)	34,622	*	674,076	*

(a) A total of 64,317,449 common units are issued and outstanding. For certain beneficial owners, the number of common units includes DSUs, 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 DSUs for the value of distributions. A director cannot redeem DSUs until the director ceases to be a member of the Board. Directors can then redeem their units for cash or common units.

(b)

Any DSUs 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 effective two percent general partner interest of the Partnership.

(e)

Based on a Schedule 13G/A filed with the SEC on February 5, 2016 by OppenheimerFunds, Inc. In this Schedule 13G/A, OppenheimerFunds, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 9,395,607 common units.

(f)

Based on a Schedule 13G filed with the SEC on January 25, 2016 by Center Coast Capital Advisors, LP. In this Schedule 13G Center Coast Capital Advisors, LP disclaims beneficial ownership, and has shared power to vote and to dispose of the 3,331,338 common units.

(g)

Based on a Schedule 13G filed with the SEC on February 3, 2016 by ALPS Advisors, Inc. In this Schedule 13G ALPS Advisors, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 3,650,030 common units.

(h)

Includes 7,254 DSUs and 1,000 common units of the Partnership.

(i)

Includes 15,759 DSUs and 715 common units of the Partnership.

(j)

Includes 9,894 DSUs and 995 TransCanada common shares.

(k)

Includes 351,523 options exercisable within 60 days for TransCanada common shares and 27,247 TransCanada common shares held in his Employee Share Savings Plan account.

(l)

Includes 68,584 options exercisable within 60 days for TransCanada common shares, 20,194 TransCanada common shares held directly, 4,752 TransCanada common shares held in his Employee Share Savings Plan accounts.

(m)

Includes 26,148 options exercisable within 60 days for TransCanada common shares and 520 TransCanada common shares held in her TransCanada 401(k) and Savings Plan.

(n)

Includes 49,679 options exercisable within 60 days for TransCanada common shares and 366 TransCanada common shares held in his Employee Share Savings Plan accounts.

(o) Includes 372 TransCanada common shares held in his TransCanada 401K and Savings Plan.

(p) Amount represents 9,250 TransCanada common shares held in his Employee Share Savings Plan account.

(q) Includes 7,568 TransCanada common shares held in his Employee Share Savings Plan account and 8,500 TransCanada common shares held jointly with his spouse.

(r) Includes 324 TransCanada common shares held in her Employee Share Savings Plan account and 1,754 TransCanada common shares held by her spouse.

(s) Includes 32,907 DSUs and 1,715 common units of the Partnership, 21,189 TransCanada common shares held directly, 8,500 TransCanada common shares held with a spouse, 589,999 options exercisable within 60 days for TransCanada common shares, 1,754 TransCanada common shares owned by immediate family members of which beneficial ownership of no common shares is disclaimed, and 51,742 TransCanada common shares held in the TransCanada Employee Share Savings Plan and 892 TransCanada common shares held in the 401K and Savings Plan.

* Less than one percent.

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

As of February 26, 2016, subsidiaries of TransCanada own 17,084,831, or 26.6 percent, of our outstanding common units, including 5,797,106 common units held by the General Partner. In addition, the General Partner owns 100 percent of our IDRs and an effective two percent general partner interest in the Partnership through which it manages and operates the Partnership. TransCanada also owns 100 percent of our Class B units. For more details regarding the Class B units, see Notes 6 and 9 within Part IV, Item 15. "Exhibits and Financial Statement Schedules."

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 average 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. Additionally, the Class B units entitle TransCanada to receive an annual distribution based on 30 percent of GTN's annual distributions exceeding certain thresholds.
Payments to our General Partner and its affiliates	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. The Class B units rank equally with common units upon liquidation.

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 $3 million for the year ended December 31, 2015.

Cash Management Programs

Great Lakes has a cash management agreement with TransCanada whereby its funds are pooled with other TransCanada affiliates. The agreement gives Great Lakes the ability to obtain short-term borrowings to provide liquidity for its 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. These contracts are on the same terms as would be available to other shippers. Great Lakes earned $125 million of transportation revenues under these contracts in 2015.

This amount represents 71 percent of total revenues earned by Great Lakes in 2015. Great Lakes also earned $2 million in affiliated rental revenue in 2015.

Revenue from TransCanada and its affiliates of $59 million is included in the Partnership's equity earnings from Great Lakes in 2015. At December 31, 2015, $17 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates.

Effective November 1, 2014, Great Lakes executed contracts with an affiliate, ANR Pipeline Company (ANR), to provide firm service in Michigan and Wisconsin. These contracts were at the maximum FERC authorized rate and were intended to replace historical contracts. On December 3, 2014, the FERC accepted and suspended Great Lakes' tariff records to become effective May 3, 2015, subject to refund. On February 2, 2015, FERC issued an Order granting a rehearing and clarification request submitted by Great Lakes, which allowed additional time for FERC to consider Great Lakes' request. Following extensive discussions with numerous shippers and other stakeholders, on April 20, 2015, ANR filed a settlement with FERC that included an agreement by ANR to pay Great Lakes the difference between the historical and maximum rates (ANR Settlement). Great Lakes provided service to ANR under multiple service agreements and rates through May 3, 2015 when Great Lakes' tariff records became effective and subject to refund. Great Lakes deferred an approximate $9 million of revenue related to services performed in 2014 and approximately $14 million of additional revenue related to services performed through May 3, 2015 under such agreements. On October 15, 2015, FERC accepted and approved the ANR Settlement. As a result, Great Lakes recognized the deferred transportation revenue of approximately $23 million in the fourth quarter of 2015.

Acquisitions

We have participated in several business acquisitions with TransCanada that were accounted for as transactions between entities under common control. For more details regarding the transactions' size, structure and terms, see Notes 6 and 22 within Part IV, Item 15. "Exhibits and Financial Statement Schedules."

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.

Total costs charged to our pipeline systems for the years ended December 31, 2015, 2014 and 2013 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2015 and 2014 are summarized in Note 16 within Part IV, Item 15. "Exhibits and Financial Statement Schedules."

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 has other routine agreements with TransCanada that arise in the ordinary course of business, including agreements for services and other transportation and exchange agreement and interconnection and balancing agreements.

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 Part III, Item 10. "Directors, Executive Officers and Corporate Governance" for additional information.

Director Independence

Please read Part III, 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)*	**2015**	2014
Audit Fees[(a)(b)]	**1,067**	922
Audit Related Fees		
Tax Fees[(c)]		
All Other Fees		
Total	**1,067**	922

(a) $200 thousand of the 2015 and 2014 Audit Fees relate to ATM equity financing and $150 thousand of the 2015 Audit Fees relate to issuance of senior unsecured notes in connection with 2015 GTN Acquisition.

(b) Includes Advisory services for Class B issuance amounting to $26 thousand.

(c) The Partnership did not engage its external auditors for any tax or other services in 2015 or 2014.

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 registered public accounting firm 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 and 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*

The exhibit list required by this Item is incorporated by reference to the Exhibit Index that follows the financial statements files as a part of this report.

No.	Description
*2.1	Agreement for purchase and sale of membership interest dated as of May 15, 2013 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 May 15, 2013).
*2.2	Agreement for purchase and sale of membership interest dated as of May 15, 2013 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 May 15, 2013).
*3.1	Third Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated April 1, 2015 (Incorporated by reference from Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed April 1, 2015).
*3.2	Certificate of Limited Partnership of TC PipeLines, LP (Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, filed on December 30, 1998).
*3.3	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 (Incorporated by reference to Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006).
*4.1	Indenture, dated as of June 17, 2011, between the Partnership and The Bank of New York Mellon, as trustee (Incorporated by reference to 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 (Incorporated by reference to 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 (Incorporated by reference to Exhibit A to the Supplemental 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 (Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed on June 14, 2011).
*4.5	Second Supplemental Indenture, dated March 13, 2015, between TC PipeLines, LP and The Bank of New York Mellon (incorporated by reference from Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed March 13, 2015).

*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 (Incorporated by reference to Exhibit 10.9 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007).
*10.1.1	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Great Lakes Gas Transmission Partnership between TransCanada GL, Inc., TC GL Intermediate Limited Partnership and Great Lakes Gas Transmission Company dated October 25, 2010 (Incorporated by reference to Exhibit 10.1.1 to TC PipeLines, LP's Form 10-K filed on February 25, 2011).
*10.2	Operating Agreement between Great Lakes Gas Transmission Limited Partnership and Great Lakes Gas Transmission Company dated April 5, 1990 (Incorporated by reference to Exhibit 10.10 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007).
*10.3	Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. dated April 6, 2006 (Incorporated by reference to Exhibit 10.2 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006).
*10.3.1	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 (Incorporated by reference to Exhibit 10.9.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.3.2	Second Amendment of Operating Agreement by and between Northern Border Pipeline Company and TransCanada Northern Border Inc. dated February 10, 2010 (Incorporated by reference to Exhibit 10.9.2 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*10.4	Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated December 19, 2006 (Incorporated by reference to Exhibit 10.11 to TC PipeLines, LP's Form 10-K filed on March 2, 2007).
*10.4.1	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 (Incorporated by reference to Exhibit 10.10.1 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.4.2	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 (Incorporated by reference to Exhibit 10.10.2 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.4.3	Third Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2008 (Incorporated by reference to Exhibit 10.10.3 to TC PipeLines, LP's Form 10-K filed on February 27, 2009).
*10.4.4	Fourth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2009 (Incorporated by reference to Exhibit 10.10.4 to TC PipeLines, LP's Form 10-K filed on February 26, 2010).
*10.4.5	Fifth Amendment to Operating Agreement by and between Tuscarora Gas Transmission Company and TransCanada Northern Border Inc. dated December 31, 2010 (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 27, 2011).

*10.5	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 (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 4, 2009).
*10.6	Contribution, Conveyance and Assumption Agreement among TC PipeLines, LP and certain other parties dated May 28, 1999 (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-K filed on March 28, 2000).
*10.7	Form of Conveyance, Contribution and Assumption Agreement among Northern Plains Natural Gas Company, Northwest Border Pipeline Company, Pan Border Gas Company, Northern Border Partners, L.P., and Northern Border Intermediate Limited Partnership (Incorporated by reference to Exhibit 10.16 to Northern Border Pipeline Company's Form S-1 Registration Statement filed on July 16, 1993 (Registration No. 33-66158)).
*10.8	Form of Contribution, Conveyance and Assumption Agreement 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. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form S-1/A filed on May 3, 1999).
*10.9	Membership Interest Purchase Agreement by and between Northern Border Pipeline Company and TransCanada Pipeline USA Ltd. dated August 28, 2008, (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on November 3, 2008).
*10.10	Common Unit Purchase Agreement by and between TC PipeLines, LP and TransCan Northern Ltd. dated July 1, 2009 (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*10.11	Exchange Agreement by and between TC PipeLines, LP and TC PipeLines GP, Inc. dated July 1, 2009 (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on July 1, 2009).
*10.12	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. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 19, 2011).
*10.13	First Amendment to Second Amended and Restated Revolving Credit and Term Loan Agreement, dated as of November 20, 2012, by and among TC PipeLines, LP, the Lenders, and SunTrust Bank, as administrative agent for the Lenders. (Incorporated by reference to Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 28, 2013).
*10.14	Guaranty by TransCanada Pipeline USA Ltd. dated May 15, 2013 with respect to the obligations of TransCanada American Investments Ltd. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on May 15, 2013).
*10.15	Guaranty by TransCanada Pipeline USA Ltd. dated May 15, 2013 with respect to the obligations of TC Continental Pipeline Holdings Inc. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on May 15, 2013).
*10.16	Term Loan Agreement, dated as of July 1, 2013, between the Partnership and the lenders (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 3, 2013).

*10.17	TC PipeLines GP, Inc. Deferred Share Unit Plan for Non-Employee Directors (2013), effective as of January 1, 2014, as amended on December 16, 2013. (Incorporated by reference to Exhibit 10.19 to TC PipeLines, LP's Form 10-K filed on February 28, 2014).
*10.18	Agreement for purchase and sale of membership interest dated as of October 1, 2014 between TC Continental Pipeline Holdings Inc. and TC PipeLines Intermediate Limited Partnership (Incorporated by reference to Exhibit 10.1 to the TC PipeLines, LP's Form 8-K filed October 1, 2014).
*10.19	Agreement for Purchase and Sale of Membership Interest dated as of February 24, 2015 between TransCanada American Investments Ltd., as Seller, and the Partnership, as Buyer (Incorporated by reference to Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed February 25, 2015).
*10.20	Contribution Agreement dated April 1, 2015 by and among TC PipeLines, LP, TC PipeLines GP, Inc. and TC PipeLines Intermediate Limited Partnership. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed August 7, 2015).
*10.21	Term Loan Agreement dated September 30, 2015 between the Partnership and Bank of America, N.A. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed November 6, 2015).
*10.22	Agreement for Purchase and Sale of Partnership Interest by and between TCPL Portland Inc., as Seller, and TC PipeLines Intermediate Limited Partnership, as Buyer (Exhibit 10.1 to TC PipeLines LP's Form 8-K filed on November 6, 2015).
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 Northern Border Pipeline Company.
23.3	Consent of KPMG LLP with respect to the financial statements of Great Lakes Gas Transmission Limited Partnership.
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 FT9141 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 12, 2008. (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008).
*99.2	Transportation Service Agreement FT9158 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated March 14, 2008. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on August 5, 2008).
*99.3	Transportation Service Agreement IT11986 between Great Lakes Gas Transmission Limited Partnership and TransCanada Gas Storage USA Inc., dated February 27, 2009. (Incorporated by reference to Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2009).
*99.4	Transportation Service Agreement FT16128 between Great Lakes Transmission Limited Partnership and TransCanada PipeLines Limited, dated March 9, 2011 (Incorporated by reference to Exhibit 99.11 to TC PipeLines, LP's Form 10-K filed on February 28, 2012).

*99.5	Transportation Service Agreement FT17190 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated February 6, 2012 (Incorporated by reference to Exhibit 99.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2012).
*99.6	Transportation Service Agreement FT17193 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated February 6, 2012 (Incorporated by reference to Exhibit 99.3 to TC PipeLines, LP's Form 10-Q filed on April 30, 2012).
*99.7	Transportation Service Agreement FT17593 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated October 30, 2012. (Incorporated by reference to Exhibit 99.16 to TC PipeLines, LP's Form 10-K filed on February 28, 2013).
*99.8	Transportation Service Agreement FT17196 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, dated December 3, 2012. (Incorporated by reference to Exhibit 99.17 to TC PipeLines, LP's Form 10-K filed on February 28, 2013).
99.9	Transportation Service Agreement FT18138 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2016.
99.10	Transportation Service Agreement FT18139 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2016.
99.11	Transportation Service Agreement FT18147 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2016.
99.12	Transportation Service Agreement FT18150 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date November 01, 2016.
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.

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Indicates exhibits incorporated by reference.

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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 26th day of February 2016.

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

By: /s/ Brandon Anderson

Brandon Anderson
President
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ Nathaniel A. Brown

Nathaniel A. Brown
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/ Karl R. Johannson Karl R. Johannson	Chair	February 26, 2016
/s/ Brandon Anderson Brandon Anderson	President and Principal Executive Officer	February 26, 2016
/s/ Nathaniel A. Brown Nathaniel A. Brown	Controller and Principal Financial Officer	February 26, 2016
/s/ M. Catharine Davis M. Catharine Davis	Director	February 26, 2016
/s/ Joel E. Hunter Joel E. Hunter	Director	February 26, 2016
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 26, 2016
/s/ Jack F. Stark Jack F. Stark	Director	February 26, 2016
/s/ Malyn K. Malquist	Director	February 26, 2016

Signature	Title	Date
Malyn K. Malquist		

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
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, 2015 and 2014, 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, 2015. We also have audited TC PipeLines, LP's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* 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 TC PipeLines, LP'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 Partnership'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, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, 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, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/s/ KPMG LLP

Houston, Texas
February 26, 2016

TC PIPELINES, LP

CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	2015	2014
Assets		
Current Assets		
Cash and cash equivalents	39	26
Accounts receivable and other (Note 19)	35	35
Inventories	7	7
	81	68
Investments in unconsolidated affiliates (Note 4)	965	1,177
Plant, property and equipment, net (Note 5)	1,949	1,968
Goodwill	130	130
Other assets	8	6
	3,133	3,349
Liabilities and Partners' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	32	23
Accounts payable to affiliates (Note 16)	5	15
Accrued interest	8	4
Short-term loan (Note 7)		170
Current portion of long-term debt (Note 7)	14	79
	59	291
Long-term debt (Note 7)	1,896	1,446
Other liabilities (Note 8)	27	26
	1,982	1,763
Partners' Equity (Note 9)		
Common units	1,021	1,325
Class B units	107	
General partner	25	29
Accumulated other comprehensive loss (Note 10)	(2)	(2)
Controlling interests	1,151	1,352
Non-controlling interests		234
	1,151	1,586
	3,133	3,349

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

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 (millions of dollars except per common unit amounts)	2015	2014	2013[(a)]
Transmission revenues	**344**	336	341
Equity earnings from unconsolidated affiliates (Note 4)	**97**	88	67
Impairment of equity-method investment (Note 4)	**(199)**		
Operation and maintenance expenses	**(53)**	(54)	(55)
Property taxes	**(19)**	(21)	(23)
General and administrative	**(9)**	(9)	(9)
Depreciation	**(85)**	(86)	(86)
Financial charges and other (Note 11)	**(56)**	(50)	(44)
Net income	**20**	204	191
Net income attributable to non-controlling interests	**7**	32	36
Net income attributable to controlling interests	**13**	172	155
Net income (loss) attributable to controlling interest allocation (Note 12)			
Common units	**(2)**	168	126
General Partner	**3**	4	3
TransCanada and its subsidiaries	**12**		26
	13	172	155
Net income (loss) per common unit (Note 12) basic and diluted	**$(0.03)**	$2.67	$2.13
Weighted average common units outstanding *(millions)* basic and diluted	**63.9**	62.7	58.9
Common units outstanding, end of year *(millions)*	**64.3**	63.6	62.3

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

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	2015	2014	2013[(a)]
Net income	**20**	204	191
Other comprehensive income			
Change in fair value of cash flow hedges (Note 18)		(1)	
Reclassification to net income of gains and losses on cash flow hedges (Note 10)			

Year ended December 31 (millions of dollars)	**2015**	**2014**	**2013**[(a)]
Total comprehensive income	**20**	203	191
Comprehensive income attributable to non-controlling interests	**7**	32	36
Comprehensive income attributable to controlling interests	**13**	171	155

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

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

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2015**	**2014**	**2013[(a)]**
Cash Generated From Operations			
Net income	**20**	204	191
Depreciation	**85**	86	86
Impairment of equity-method investment (Note 4)	**199**		
Amortization of debt issue costs (Note 11)	**1**	1	1
Accrual for costs related to acquisition of 49.9% interest in PNGTS (Note 22)	**2**		
Equity earnings in excess of cumulative distributions:			
Great Lakes	**(3)**		
Equity allowance for funds used during construction	**(1)**		
Change in other liabilities			2
Change in operating working capital (Note 14)	**(9)**	17	(8)
	294	308	272
Investing Activities			
Cumulative distributions in excess of equity earnings:			
Northern Border	**25**	18	20
Great Lakes		9	14
Investment in Great Lakes (Note 4)	**(9)**	(9)	(9)
Investment in Northern Border (Note 4)			(31)
Acquisition of the remaining 30 percent interest in GTN (Note 6)	**(264)**		
Acquisition of the remaining 30 percent interest in Bison (Note 6)		(217)	
Acquisition of interests in GTN and Bison, net of cash acquired (Note 6)		(25)	(921)
Adjustment to the 2011 Acquisition			1
Capital expenditures	**(54)**	(10)	(15)
Change in affiliate demand loan receivable			21
Other	**1**		
	(301)	(234)	(920)
Financing Activities			
Distributions paid (Note 13)	**(228)**	(212)	(188)
Distributions paid to non-controlling interests	**(9)**	(50)	(52)
Change in affiliate demand loan payable			(15)
ATM equity issuance, net (Note 9)	**44**	73	
Equity issuance, net (Note 9)			381
Equity contribution by General Partner (Note 6)	**2**		
Long-term debt issued, net of discount (Note 7)	**618**	35	937
Short-term loan issued (Note 7)		170	
Debt repayments (Note 7)	**(404)**	(89)	(372)
Debt issuance costs	**(3)**		(2)
Equity contribution from Bison's former parent (Note 16)			18
Distributions paid to former parent of GTN and Bison			(37)
	20	(73)	670
Increase/(decrease) in cash and cash equivalents	**13**	1	22
Cash and cash equivalents, beginning of year	**26**	25	3
Cash and cash equivalents, end of year	**39**	26	25

Year ended December 31 (millions of dollars)	**2015**	**2014**	**2013**[(a)]
Interest payments made	**54**	47	42
Supplemental information about non-cash investing and financing activities			
Accrual for Carty Lateral consideration payment (Note 6)			25
Accrual for costs related to construction of Carty Lateral (Note 14)	**10**		
Issuance of Class B units to TransCanada (Note 6)	**95**		

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

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

	Limited Partners							
(millions of units) (millions of dollars) (unaudited)	**Common Units**		**Class B Units**	**General Partner**	**Accumulated Other Comprehensive Loss[(a)]**	**Non-Controlling Interests**	**Equity of former parent of GTN and Bison[(b)]**	**Total Equity**
Partners' Equity at December 31, 2012	53.5	1,275		27	(1)	448	673	2,422
Net income		152		3		36		191
Net income attributed to former parent of GTN and Bison		(26)					26	
Distributions to former parent of GTN and Bison							(37)	(37)
Equity Issuance, net (Note 9)	8.8	373		8				381
Distributions		(184)		(4)		(52)		(240)
Excess purchase price paid over net acquired assets (Note 6)		(268)		(6)				(274)
Equity contribution from Bison's former parent (Note 16)						8	10	18
Former parent carrying amount of acquired entities							(672)	(672)
Adjustment to the 2011 Acquisition		1						1
Other		(1)						(1)
Partners' Equity at December 31, 2013	62.3	1,322		28	(1)	440		1,789
Net income		168		4		32		204
Other Comprehensive Loss					(1)			(1)
ATM Equity Issuance, net (Note 9)	1.3	71		2				73
Acquisition of the remaining interest in Bison (Note 6)		(29)				(188)		(217)
Distributions		(207)		(5)		(50)		(262)
	63.6	1,325		29	(2)	234		1,586

Partners' Equity at December 31, 2014	**Limited Partners**						**Equity of former parent of GTN and Bison[b]**	
Issuance of Class B Units (Note 6 and 9)			1.9	95				95
Net income (loss)		(2)		12	3		7	20
Other Comprehensive Loss								
ATM Equity Issuance, net (Note 9)	0.7	43			1			44
Acquisition of the remaining interest in GTN (Note 6)		(124)			(3)		(232)	(359)
Equity Contribution (Note 6)					2			2
Distributions		(221)			(7)		(9)	(237)
Partners' Equity at December 31, 2015	**64.3**	**1,021**	**1.9**	**107**	**25**	**(2)**		**1,151**

(a) Losses related to cash flow hedges reported in Accumulated Other Comprehensive Loss and expected to be reclassified to net income in the next 12 months are estimated to be $1 million. These estimates assume constant interest rates over time; however, the amounts reclassified will vary based on actual value of interest rates at the date of settlement.

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

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:

Pipeline	Length	Description	Ownership
Gas Transmission Northwest LLC (GTN)	1,377 miles	Extends between an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100 percent
Northern Border Pipeline Company (Northern Border)	1,408 miles	Extends between the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana, south of Chicago. Northern Border is capable of receiving natural gas from Canada, the Williston Basin and Rocky Mountain area for deliveries to the Midwest. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50 percent
Bison Pipeline LLC (Bison)	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison transports natural gas from the Powder River Basin to Midwest markets.	100 percent
Great Lakes Gas Transmission Limited Partnership (Great Lakes)	2,115 miles	Connects with the TransCanada Mainline at the Canadian border near Emerson, Manitoba, Canada and St. Clair, Michigan, near Detroit. Great Lakes is a bi-directional pipeline that can receive and deliver natural gas at multiple points along its system. TransCanada owns the remaining 53.55 percent of Great Lakes.	46.45 percent
North Baja Pipeline, LLC (North Baja)	86 miles	Extends between an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona and an interconnection with a natural gas pipeline near Ogilby, California on the Mexican border transporting natural gas in the southwest. North Baja is a bi-directional pipeline.	100 percent
Tuscarora Gas Transmission Company (Tuscarora)	305 miles	Extends between the GTN pipeline near Malin, Oregon to its terminus near Reno, Nevada and delivers natural gas in northeastern California and northwestern Nevada.	100 percent
Portland Natural Gas Transmission	295 miles	Connects with the TransQuebec and Maritimes Pipeline (TQM) at the Canadian border to deliver natural gas to customers in the U.S. northeast. TransCanada owns	49.9 percent(a)

Pipeline	Length	Description	Ownership
System (PNGTS)		11.81 percent of PNGTS. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS.	

(a)
Effective January 1, 2016 (Refer to Note 22)

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. The General Partner owns 5,797,106 common units, 100 percent of our IDRs and an effective two percent general partner interest in the Partnership at December 31, 2015. TransCanada also indirectly holds an additional 11,287,725 common units, for total ownership of 26.6 percent of our outstanding common units and 100 percent of our Class B units at December 31, 2015 (Refer to Note 6).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying financial statements and related notes have been prepared in accordance with United States generally accepted accounting principles (GAAP) and amounts are stated in U.S. dollars. The financial statements and notes present the financial position of the Partnership as of December 31, 2015 and 2014 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2015, 2014 and 2013.

(a) Basis of Presentation

The Partnership consolidates its investments in GTN, Bison, North Baja and Tuscarora, over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. The Partnership uses the equity method of accounting for its investments in Northern Border and Great Lakes, over which it is able to exercise significant influence.

On April 1, 2015 and October 1, 2014, the Partnership acquired the remaining 30 percent interest in GTN and Bison, respectively, from subsidiaries of TransCanada. These acquisitions resulted in GTN and Bison being wholly-owned by the Partnership. Prior to these transactions, the remaining 30 percent interests held by subsidiaries of TransCanada were reflected as non-controlling interests in the Partnership's consolidated financial statements. The acquisitions of these already-consolidated entities were accounted as a transaction between entities under common control, similar to a pooling of interests, whereby the acquired interests were recorded at TransCanada's carrying value and the total excess purchase price paid was recorded as a reduction in Partners' Equity. Refer to Note 6 for additional disclosures regarding these acquisitions.

On July 1, 2013, the Partnership acquired a 45 percent membership interest in each of GTN and Bison (the 2013 Acquisition) from subsidiaries of TransCanada increasing the Partnership's ownership in each of GTN and Bison to 70 percent. The 2013 Acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of GTN and Bison were recorded at TransCanada's carrying value and the Partnership's historical financial information, except net income per common unit, was recast to consolidate GTN and Bison for all periods presented. Refer to Note 6 for additional disclosure regarding the 2013 Acquisition.

(b) Use of Estimates

The preparation of financial statements 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.

(c) Cash and Cash Equivalents

The Partnership's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

(d) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method.

(e) Inventories

Inventories primarily consist of materials and supplies and are carried at the lower of weighted average cost or market.

(f) Plant, Property and Equipment

Plant, property and equipment 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. Pipeline facilities and compression equipment have an estimated useful life of 20 to 77 years and metering and other equipment ranges from 5 to 77 years. Depreciation is calculated on a straight-line composite basis over the assets' estimated useful lives. 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.

(g) Impairment of Equity Method Investments

We review our equity method investments when a significant event or change in circumstances has occurred that may have an adverse effect on the fair value of each investment. When such events or changes occur, we compare the estimated fair value to the carrying value of the related investment. We calculate the estimated fair value of an investment in an equity method investee using an income approach and market approach. The development of fair value estimates requires significant judgment including estimates of future cash flows, which is dependent on internal forecasts, estimates of the long-term rate of growth for the investee, estimates of the useful life over which cash flows will occur, and determination of weighted average cost of capital. The estimates used to calculate the fair value of an investee can change from year to year based on operating results and market conditions. Changes in these estimates and assumptions could materially affect the determination of fair value and our assessment as to whether an investment in an equity method investee has suffered an impairment.

If the estimated fair value of an investment is less than its carrying value, we are required to determine if the decline in fair value is other than temporary. This determination considers the aforementioned valuation methodologies, the length of time and the extent to which fair value has been less than carrying value, the financial condition and near-term prospects of the investee, including any specific events which may influence the operations of the investee, the intent and ability of the holder to retain its investment in the investee for a period of time sufficient to allow for any anticipated recovery in market value, and other facts and circumstances. If the fair value of an investment is less than its carrying value and the decline in value is determined to be other than temporary, we record an impairment charge.

During the fourth quarter of 2015, we recognized an impairment charge on our investment in Great Lakes amounting to $199 million (See Note 4 for further information).

(h) Impairment of Long-lived Assets

The Partnership reviews long-lived assets, such as plant, property and equipment for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

(i) Partners' Equity

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

(j) Revenue Recognition

Transmission revenues 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, 2015, 2014 and 2013, the Partnership has not recognized any transmission revenue that is subject to possible refund.

(k) 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.

(l) Acquisitions and Goodwill

The Partnership accounts for business acquisitions from third parties using the acquisition 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 and is tested on an annual basis for impairment or more frequently if any indicators of impairment are evident. The Partnership initially assesses qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired. If the Partnership does not conclude that it is more likely than not that fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded.

The Partnership accounts for business acquisitions between itself and TransCanada as transactions between entities under common control. Using this approach, the assets and liabilities of the acquired entities are recorded at TransCanada's carrying value. In the event recasting is required, the Partnership's historical financial information will be recast, except net income per common unit, 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 in 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 in Partners' Equity.

(m) Fair Value Measurements

For cash and cash equivalents, receivables, accounts payable, certain accrued expenses and short-term debt, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments and the interest rate swap agreements, fair value is estimated based upon market values (if applicable) or on the current interest rates available to us for debt with similar terms and remaining maturities. Considerable judgment is required in developing these estimates.

(n) 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.

(o) Asset Retirement Obligation

The Partnership recognizes the fair value of a liability for asset retirement obligations in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

The scope and timing of asset retirements related to natural gas pipelines is indeterminable. As a result, the Partnership has recorded no asset retirement obligations as of December 31, 2015 and 2014.

(p) Government Regulation

The Partnership's subsidiaries are subject to regulation by 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 timing of recognition of certain revenues and expenses in our regulated business may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and rates. 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. At December 31, 2015, the Partnership had regulatory assets amounting to $2 million reported as part of accounts receivable and other in the balance sheet representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers continually (2014   nil). Regulatory liabilities are included in other long-term liabilities (refer to Note 8). Allowance for funds used during construction is capitalized and included in plant, property and equipment.

(q) 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 ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09 "Revenue from Contracts with Customers (Topic 606)." This guidance supersedes the revenue recognition requirements in Topic 605, Revenue Recognition and most industry-specific guidance. This new guidance requires that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. On July 9, 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also voted to permit early adoption of the standard, but not before the original effective date of December 15, 2016. This new guidance, once effective, allows two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. The Partnership is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its consolidated financial statements.

Consolidation

In February 2015, the FASB issued ASU No. 2015-02 "Consolidation (Topic 810)," an amendment of previously issued guidance on consolidation. This updated guidance requires that an entity evaluate whether it should consolidate certain legal entities. All legal entities are subject to reevaluation under the revised consolidation model. This guidance is effective from January 1, 2016 and early application is permitted. Application of this amendment could be performed using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption. Alternatively, the amendment could be applied retrospectively. The Partnership is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its consolidated financial statements.

Imputation of interest

In April 2015, the FASB issued ASU No. 2015-03 "Interest Imputation of Interest (Subtopic 835-30)," an amendment of previously issued guidance on imputation of interest. This updated guidance requires debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount or premiums. The recognition and measurement for debt issuance costs would not be affected. This guidance is effective from January 1, 2016 and early application is permitted. This guidance should be adopted on a retrospective basis, wherein the balance sheet of each individual period presented would be adjusted to reflect the period-specific effects of applying the new guidance. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in Other Assets to an offset of their respective debt liabilities.

Earnings Per Share

In April 2015, the FASB issued ASU No. 2015-06 "Earnings Per Share (Topic 260)," an amendment of previously issued guidance on earnings per share (EPS) as it is being calculated by master limited partnerships. This updated guidance specifies that for purposes of calculating historical EPS under the two-class method, the earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner interest, and previously reported EPS of the limited partners would not change as a result of a dropdown transaction. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the dropdown transaction occurs are also required. This guidance is effective from January 1, 2016 and early application is permitted. This guidance should be adopted on a retrospective basis to all financial statements presented. The Partnership does not expect the adoption of this new standard to have a material effect on its consolidated financial statements.

Business Combinations

In September 2015, the FASB issued ASU No. 2015-16 "Business Combinations (Topic 805)," which replaces the requirement that an acquirer in a business combination account for measurement period adjustments retrospectively with a requirement that an acquirer recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amended guidance requires that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The new guidance is effective January 1, 2016 and will be applied prospectively. The Partnership does not expect the adoption of this new standard to have a material effect on its consolidated financial statements.

NOTE 4 INVESTMENTS IN UNCONSOLIDATED AFFILIATES

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

		Equity Earnings from Unconsolidated Affiliates(b)			Investment in Unconsolidated Affiliates	
		Year ended December 31			December 31	
(millions of dollars)	Ownership Interest at December 31, 2015	2015	2014	2013	2015	2014
Northern Border(a)	50%	66	69	64	480	505
Great Lakes	46.45%	31	19	3	485(c)	672
		97	88	67	965	1,177

(a) Equity earnings 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) Equity Earnings represents our share in investee's earnings and does not include any impairment charge on the equity method investment recorded as a reduction of carrying value of these investments.

(c) During the fourth quarter of 2015, we recognized an impairment charge on our investment in Great Lakes amounting to $199 million. See discussion below.

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.

Northern Border has a FERC-approved settlement agreement which established maximum long-term transportation rates and charges on the Northern Border system effective January 1, 2013. Northern Border is required to file for new rates no later than January 1, 2018.

The Partnership recorded no undistributed earnings from Northern Border for the years ended December 31, 2015, 2014 and 2013.

At December 31, 2015 and 2014, the Partnership had a $117 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. As of December 31, 2015, no impairment has been identified in our investment in Northern Border.

The summarized financial information for Northern Border is as follows:

December 31 (millions of dollars)	2015	2014
Assets		
Cash and cash equivalents	27	41
Other current assets	33	34
Plant, property and equipment, net	1,124	1,163
Other assets	18	34
	1,202	1,272
Liabilities and Partners' Equity		
Current liabilities	39	64
Deferred credits and other	26	22
Long-term debt, including current maturities	411	411
Partners' equity		
Partners' capital	728	777
Accumulated other comprehensive loss	(2)	(2)
	1,202	1,272

Year ended December 31 (millions of dollars)	2015	2014	2013
Transmission revenues	286	293	286
Operating expenses	(70)	(72)	(75)
Depreciation	(60)	(59)	(58)
Financial charges and other	(22)	(22)	(23)
Net income	134	140	130

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.

On November 14, 2013, FERC approved a settlement between Great Lakes and its customers to modify its transportation rates effective November 1, 2013. The settlement increases maximum recourse transportation rates by approximately 21 percent. The settlement also requires that Great Lakes file for new rates to be in effect no later than January 1, 2018.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2015, 2014, and 2013.

The Partnership made equity contributions to Great Lakes of $4 million and $5 million in the first and fourth quarter of 2015, respectively. These amounts represent the Partnership's 46.45 percent share of a $9 million and $10 million cash call from Great Lakes to make scheduled debt repayments.

Despite the recent improvement in income from our investment in Great Lakes since 2013, including favorable current year results, its long-term value has been adversely impacted by the changing natural gas flows in its market region as well as our conclusion in the fourth quarter that other strategic alternatives to increase its utilization or revenue were no longer feasible. As a result, we determined that the carrying value of our investment in Great Lakes was in excess of its fair value and that the decline is not temporary. Accordingly, we concluded that the carrying value of our investment in Great Lakes was impaired.

Our analysis determined that the fair value of our investment in Great Lakes is $465 million, resulting in an impairment charge of $199 million in the fourth quarter of 2015, reflected as Impairment of equity-method investment on our Statement of Income for the year ended December 31, 2015. The impairment charge reduced the difference between the carrying value of our investment in Great Lakes and the underlying equity in the net assets, which was reduced to $260 million at December 31, 2015 (2014 $458 million) and represents the equity method goodwill remaining in our investment in Great Lakes relating to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes.

Our assumptions related to the estimated fair value of our remaining equity investment in Great Lakes could be negatively impacted by near and long-term conditions including:

- future regulatory rate action or settlement,

- valuation of Great lakes in future transactions,

- changes in customer demand at Great Lakes for pipeline capacity and services,

- changes in North American natural gas production in the major producing basins,

- changes in natural gas prices and natural gas storage market conditions, and

- changes in other long-term strategic objectives.

There is a risk that adverse changes in these key assumptions could result in additional future impairment of the carrying value of our investment in Great Lakes.

The summarized financial information for Great Lakes is as follows:

December 31 (millions of dollars)	2015	2014
Assets		
Current assets	86	66
Plant, property and equipment, net	727	748
	813	814
Liabilities and Partners' Equity		
Current liabilities	31	38
Long-term debt, including current maturities	297	316
Partners' equity	485	460
	813	814

Year ended December 31 (millions of dollars)	2015	2014	2013
Transmission revenues	177	146	124
Operating expenses	(59)	(53)	(60)
Depreciation	(28)	(28)	(31)
Financial charges and other	(23)	(25)	(27)
Net income	67	40	6

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

The following table includes plant, property and equipment from our consolidated subsidiaries.

	2015			2014		
December 31 (millions of dollars)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Pipeline	2,086	(638)	1,448	2,038	(574)	1,464
Compression	516	(134)	382	514	(126)	388
Metering and other	156	(39)	117	145	(37)	108
Construction in progress	2		2	8		8
	2,760	(811)	1,949	2,705	(737)	1,968

NOTE 6 ACQUISITIONS

2015 GTN Acquisition

On April 1, 2015, the Partnership acquired the remaining 30 percent interest in GTN from a subsidiary of TransCanada (2015 GTN Acquisition), which resulted in GTN being wholly-owned by the Partnership. The total purchase price of the 2015 GTN Acquisition was $446 million plus the final purchase price adjustment of $11 million, for a total of $457 million. The purchase price consisted of $264 million in cash (including the final purchase price adjustment of $11 million), the assumption of $98 million in proportional GTN debt and the issuance of 1,900,000 new Class B units to TransCanada valued at $50 each, representing a limited partner interest in the Partnership with a total value of $95 million.

The Partnership funded the cash portion of the transaction using a portion of the proceeds received on our March 13, 2015 debt offering (refer to Note 7). The Class B units entitle TransCanada to a distribution based on 30 percent of GTN's annual distributions as follows: (i) 100 percent of distributions above $20 million through March 31, 2020; and (ii) 25 percent of distributions above $20 million thereafter. Under the terms of the Partnership Agreement, the Class B distribution will be initially calculated to equal 30 percent of GTN's distributable cash flow for the nine months ended December 31, 2015, less $15 million.

Prior to this transaction, the remaining 30 percent interest held by a subsidiary of TransCanada was reflected as a non-controlling interest in the Partnership's consolidated financial statements. The 2015 GTN Acquisition of this already-consolidated entity was accounted as a transaction between entities under common control, similar to a pooling of interests, whereby the acquired interest was recorded at TransCanada's carrying value and the total excess purchase price paid was recorded as a reduction in Partners' Equity.

The net purchase price was allocated as follows:

(millions of dollars)

Net Purchase Price(a)	359
Less: TransCanada's carrying value of non-controlling interest at April 1, 2015	232
Excess purchase price(b)	127

(a)
Total purchase price of $457 million less the assumption of $98 million of proportional GTN debt by the Partnership.

(b)
The excess purchase price of $127 million was recorded as a reduction in Partners' Equity.

Our General Partner also contributed approximately $2 million to maintain its effective two percent interest in the Partnership.

2014 Bison Acquisition

On October 1, 2014, the Partnership acquired the remaining 30 percent interest in Bison from a subsidiary of TransCanada. The total purchase price of the 2014 Bison Acquisition was $215 million plus purchase price adjustments of $2 million. The acquisition of Bison was financed through combinations of (i) net proceeds from the ATM Program (refer to Note 9), and (ii) short-term financing (refer to Note 7).

Prior to this transaction, the remaining 30 percent interest held by a subsidiary of TransCanada was reflected as non-controlling interest in the Partnership's consolidated financial statements. The 2014 Bison Acquisition of this already-consolidated entity was accounted as a transaction between entities under common control, similar to a pooling of interests, whereby the acquired interest was recorded at TransCanada's carrying value and the total excess purchase price paid was recorded as a reduction in Partners' Equity.

The purchase price was allocated as follows:

(millions of dollars)

Total cash consideration	217
TransCanada's carrying value of non-controlling interest at October 1, 2014	188
Excess purchase price	29

The excess purchase price of $29 million was recorded as a reduction in Partners' Equity.

2013 Acquisition

On July 1, 2013, the Partnership acquired a 45 percent membership interest in each of GTN and Bison from subsidiaries of TransCanada, increasing the Partnership's ownership in each GTN and Bison to 70 percent. The total purchase price of the 2013 Acquisition was $1,050 million plus purchase price adjustments. The purchase price consisted of (i) $750 million for the GTN membership interest (less $146 million, which reflected 45 percent of GTN's outstanding debt at the time of the 2013 Acquisition), (ii) $300 million for the membership interest in Bison, (iii) $17 million in working capital adjustments and (iv) Carty Lateral consideration of $25 million (see below).

The resulting $921 million (after working capital adjustments) paid by the Partnership was financed through a combination of (i) a public offering of 8,855,000 common units at $43.85 per common unit resulting in net proceeds of $373 million (refer to Note 9), (ii) borrowing of $500 million in term loans (refer to Note 7), (iii) a capital contribution from the General Partner of $8 million which was required to maintain the General Partner's effective two percent general partner interest in the Partnership (refer to Note 9), and (iv) a draw on the Partnership's existing $500 million Senior Credit Facility and (v) cash on hand.

Pursuant to the acquisition agreement between the Partnership and TransCanada relating to the Partnership's acquisition of an additional 45 percent membership interest in GTN, the Partnership agreed to make an additional payment of $25 million to TransCanada if Portland General Electric Company executed a firm transportation service agreement by December 31, 2014 containing agreed terms and relating to transportation on GTN's Carty Lateral. On December 11, 2013, Portland General Electric Company executed this firm transportation service agreement and as a result, the Partnership paid an additional $25 million on April 11, 2014.

The 2013 Acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of GTN and Bison were recorded at TransCanada's carrying value and the Partnership's historical financial information, except net income per common unit, was recast to consolidate GTN and Bison for all periods presented.

The purchase price was recorded as follows:

(millions of dollars)	
Current assets	67
Property, plant and equipment, net	1,792
Other assets	1
Current liabilities	(20)
Other liabilities	(21)
Long-term debt	(325)
	1,494
Non-controlling interest	(448)
Carrying value of pre-existing 25% interest in each of GTN and Bison	(374)
Carrying value of acquired 45% interest in each of GTN and Bison	672
Excess purchase price over net assets acquired (includes Carty Lateral consideration)	274
Total cash consideration including $25 million Carty Lateral consideration	**946**

As the fair market value for the additional 45 percent interests in each of GTN and Bison was greater than the acquired net assets of GTN and Bison by $262 million and $12 million, respectively, the total excess purchase price of $274 million was recorded as a reduction in Partners' Equity, including the Carty Lateral consideration. The retrospective consolidation of GTN and Bison increased net income attributable to controlling interests by $26 million for the year ended December 31, 2013. However, this amount was excluded from equity attributable to controlling interests and the historical net income per common unit was not adjusted as the pre-acquisition earnings was allocated to TransCanada (refer to Note 12).

NOTE 7 DEBT AND CREDIT FACILITIES

December 31 (millions of dollars)	**2015**	**2014**
Senior Credit Facility due 2017	**200**	330
2013 Term Loan Facility due 2018	**500**	500
Short-Term Loan Facility due 2015		170
2015 Term Loan Facility due 2018	**170**	
4.65% Unsecured Senior Notes due 2021, net of discount (2015 and 2014 nil)	**350**	350
4.375% Unsecured Senior Notes due 2025, net of $1 million discount	**349**	
5.09% Unsecured Senior Notes due 2015		75
5.29% Unsecured Senior Notes due 2020	**100**	100
5.69% Unsecured Senior Notes due 2035	**150**	150
Unsecured Term Loan Facility due 2019	**75**	
3.82% Series D Senior Notes due 2017	**16**	20

December 31 (millions of dollars)	**2015**	**2014**
	1,910	1,695
Less: current portion	**14**	249
	1,896	1,446

The Partnership's Senior Credit Facility consists of a $500 million senior revolving credit facility with a banking syndicate, maturing November 20, 2017, under which $200 million was outstanding at December 31, 2015 (2014 $330 million), leaving $300 million available for future borrowing.

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be 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 Credit Facility. The Senior 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 Credit Facility of up to $250 million, but no lender has an obligation to increase their respective share of the facility.

The LIBOR-based interest rate on the Senior Credit Facility averaged 1.44 percent for the year ended December 31, 2015 (2014 1.41 percent; 2013 1.44 percent). The interest rate was 1.50 percent at December 31, 2015 (December 31, 2014 1.41 percent).

On July 1, 2013, the Partnership entered into a term loan agreement with a syndicate of lenders for a $500 million term loan credit facility (2013 Term Loan Facility). On July 2, 2013, the Partnership borrowed $500 million under the 2013 Term Loan Facility, to pay a portion of the purchase price of the 2013 Acquisition, maturing on July 1, 2018. The 2013 Term Loan Facility bears interest based, at the Partnership's election, on the LIBOR or the base rate plus, in either case, an applicable margin. The base rate equals the highest of (i) SunTrust Bank's prime rate, (ii) 0.50 percent above the federal funds rate and (iii) 1.00 percent above one-month LIBOR. The applicable margin for the term loan is based on the Partnership's senior debt rating and ranges between 1.125 percent and 2.000 percent for LIBOR borrowings and 0.125 percent and 1.000 percent for base rate borrowings.

The LIBOR-based interest rate on the 2013 Term Loan Facility averaged 1.44 percent for the year ended December 31, 2015 (2014 1.41 percent). After hedging activity, the interest rate incurred on the Term Loan Facility averaged 1.85 percent for the year ended December 31, 2015 (2014 1.82 percent). Prior to hedging activities, the LIBOR-based interest rate was 1.50 percent at December 31, 2015 (December 31, 2014 1.41 percent).

On September 30, 2015, the Partnership entered into an agreement for a $170 million term loan credit facility (2015 Term Loan Facility). The Partnership borrowed $170 million under the 2015 Term Loan Facility to refinance its Short-Term Loan Facility which matured on September 30, 2015. The 2015 Term Loan Facility matures on October 1, 2018. The LIBOR-based interest rate on the 2015 Term Loan Facility averaged 1.47 percent for the year ended December 31, 2015. The interest rate was 1.39 percent at December 31, 2015.

The 2013 Term Loan Facility and the 2015 Term Loan Facility (Term Loan Facilities) and the Senior Credit Facility require the Partnership to maintain a certain 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]). In the quarter in which an acquisition has occurred, and the two quarters following the acquisition, the allowable leverage ratio increases to 5.50 to 1.00. Thereafter, the ratio returns to 5.00 to 1.00. The allowable ratio for the quarter ended December 31, 2015 is 5.50 to 1.00. The leverage ratio was 4.68 to 1.00 as of December 31, 2015. The Senior Credit Facility and the Term Loan Facilities contain 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 and the Term Loan Facilities may become immediately due and payable.

On March 13, 2015, the Partnership closed a $350 million public offering of senior unsecured notes bearing an interest rate of 4.375 percent maturing March 13, 2025. The net proceeds of $346 million were used to fund a portion of the acquisition of the remaining 30 percent interest in GTN (refer to Note 6) and to reduce the amount outstanding under our Senior Credit Facility. The indenture for the notes contains customary investment grade covenants.

On June 1, 2015, GTN's 5.09 percent unsecured Senior Notes matured. Also, on June 1, 2015, GTN entered into a $75 million unsecured variable rate term loan facility (Unsecured Term Loan Facility), which requires yearly principal payments until its maturity on June 1, 2019. The variable interest is based on LIBOR plus an applicable margin. The LIBOR-based interest rate on the Unsecured Term Loan Facility for the year ended December 31, 2015 averaged

1.16 percent and was 1.15 percent at December 31, 2015. GTN's Unsecured Senior Notes, along with this new Unsecured Term Loan Facility contain a covenant that limits total debt to no greater than 70 percent of GTN's total capitalization. GTN's total debt to total capitalization ratio at December 31, 2015 is 43.8 percent.

The Series D Senior Notes, which require yearly principal payments until its maturity, 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.

At December 31, 2015, 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.

The principal repayments required by the Partnership on its debt are as follows:

(millions of dollars)	
2016	**14**
2017	**222**
2018	**690**
2019	**35**
2020	**100**
Thereafter	**849**
	1,910

NOTE 8 OTHER LIABILITIES

December 31 (millions of dollars)	**2015**	**2014**
Regulatory liabilities	**24**	23
Other liabilities	**3**	3
	27	26

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates and recognizes regulatory liabilities in this respect in the balance sheet. Estimated costs associated with the future removal of transmission and gathering facilities are collected through depreciation as allowed by FERC. These amounts do not represent asset retirement obligations as defined by FASB ASC 410, *Accounting for Asset Retirement Obligations*.

NOTE 9 PARTNERS' EQUITY

At December 31, 2015, the Partnership had 64,317,449 common units outstanding, of which 47,232,618 were held by non-affiliates and 17,084,831 common units were held by subsidiaries of TransCanada, including 5,797,106 common units held by our General Partner. Additionally, TransCanada, through our General Partner, owns 100 percent of our IDRs and an effective two percent general partner interest in the Partnership. TransCanada also holds 100 percent of our 1,900,000 outstanding Class B units.

ATM Equity Issuance Program (ATM Program)

In August 2014, the Partnership entered into an Equity Distribution Agreement (the EDA) with five different financial institutions (Managers), pursuant to which, the Partnership may from time to time, offer and sell common units having an aggregate offering price of up to $200 million. Sales of such common units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by one or more of the Managers and the Partnership.

In 2015, the Partnership issued 0.7 million common units under the ATM Program generating net proceeds of approximately $43 million, plus an additional $1 million from the General Partner's to maintain its effective two percent interest. The commissions to our sales agents were approximately $0.4 million. The net proceeds were used for general partnership purposes.

In 2014, the Partnership issued 1.3 million common units under the ATM Program generating net proceeds of approximately $71 million, plus an additional $2 million from the General Partner's to maintain its effective two percent interest. The commissions to our sales agents were approximately $1 million. The net proceeds were used to finance the 2014 Bison Acquisition (refer to Note 6).

Issuance of Class B units

On April 1, 2015, we issued Class B units to TransCanada to finance a portion of the 2015 GTN Acquisition. The Class B units entitle TransCanada to an annual distribution which is an amount based on 30 percent of cash distributions from GTN above certain annual thresholds (refer to Note 6). The Class B units contain no mandatory or optional redemption features and are also non-convertible, non-exchangeable, non-voting and rank equally with common units upon liquidation.

The Class B units' equity account will be increased by the excess of 30 percent of GTN's distributions over the annual threshold until such amount is declared for distribution and paid in the first quarter beginning 2016 and annually thereafter.

Equity issuance in connection with the 2013 Acquisition

On May 22, 2013, the Partnership closed a public offering of 8,855,000 common units, including 1,155,000 common units purchased pursuant to the exercise of the underwriters' option to purchase additional common units, at a price to the public of $43.85 per common unit for gross proceeds of $388 million and net proceeds of $373 million after unit issuance costs. The General Partner maintained its effective two percent general partner interest in the Partnership by contributing $8 million to the Partnership in connection with the offering. (Refer to Note 6).

NOTE 10 ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in accumulated other comprehensive loss (AOCL) by components are as follows:

(millions of dollars)	Cash flow hedges
Balance at December 31, 2012	(1)
Other comprehensive loss before reclassifications	
Amounts reclassified from AOCL	
Net other comprehensive loss	
Balance at December 31, 2013	(1)
Other comprehensive loss before reclassifications	(1)
Amounts reclassified from AOCL	
Net other comprehensive loss	
Balance at December 31, 2014	(2)
Other comprehensive loss before reclassifications	
Amounts reclassified from AOCL	
Net other comprehensive loss	
Balance as of December 31, 2015	(2)

NOTE 11 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	2015	2014	2013(a)
Interest expense	58	48	42
Amortization of debt issue costs	1	1	1
Net realized loss related to the interest rate swaps and options	2	2	1
Other	(5)	(1)	

Year ended December 31 (millions of dollars)	2015	2014	2013(a)
	56	50	44

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

NOTE 12 NET INCOME (LOSS) PER COMMON UNIT

Net income (loss) per common unit is computed by dividing net income attributable to controlling interests, after deduction of amounts attributable to the General Partner and to TransCanada and its subsidiaries, by the weighted average number of common units outstanding.

The amounts allocable to the General Partner equals 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 (refer to Note 13).

The amounts allocable to TransCanada and its subsidiaries represents amount allocable to the Class B units (refer to Note 6-2015 GTN Acquisition) and amounts allocable to GTN and Bison's former parent as a result of recast (refer to Note 6- 2013 Acquisition).

The amount allocable to GTN and Bison's former parent represents income of GTN and Bison prior to the 2013 Acquisition.

The amount allocable to the Class B units in 2015 equals an amount based upon 30 percent of GTN's distributable cash flow during the nine months ended December 31, 2015 less $15 million.

Net income (loss) per common unit was determined as follows:

(millions of dollars, except per common unit amounts)	2015	2014	2013(a)
Net income allocable to controlling interests	13	172	155
Net income attributable to GTN's and Bison's former parent			26(b)
Net income allocable to General and Limited Partners(b)	13	172	129
Incentive distributions attributable to the General Partner(c)	3	1	
Net income attributable to the Class B units(d)	12		
Net income (loss) allocable to the General Partner and common units	(2)	171	129
Net Income (loss) allocable to the General Partner's two percent interest		3	3
Net income (loss) attributable to common units	(2)	168	126
Weighted average common units outstanding *(millions)* basic and diluted	63.9	62.7	58.9
Net income (loss) per common unit basic and diluted	$(0.03)	$2.67	$2.13

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

(b) Net income allocable to General and Limited Partners excludes net income attributed to GTN's and Bison's former parent as it was allocated to TransCanada and was not allocable to either the general partner, common units or Class B units (refer to Note 6 2013 Acquisition).

(c) Net income allocable to General and Limited Partners is allocated based on their respective participation rights, after giving effect to any priority income allocation for incentive distributions that are allocated 100 percent to the General Partner. Under the terms of the Partnership Agreement, for any quarterly period, the participation of the IDRs is limited to the available cash distributions declared. Accordingly, incentive distributions allocated to the General Partner was based from the Partnership's available cash during the current reporting period, but declared and paid in the subsequent reporting period.

(d) As discussed in Notes 6 and 9, the Class B units entitle TransCanada to a distribution which is an amount based on 30 percent of GTN's distributions after achieving certain annual thresholds. The distribution will be payable in the first quarter with respect to the prior year's distributions. Consistent with the application of Accounting Standards Codification (ASC) Topic 260 "Earnings per share," the Partnership allocated a portion of net income attributable to controlling interests to the Class B units upon 30 percent of GTN's total distributable cash flows exceeding $15 million for the nine month period ended December 31, 2015. During the nine months ended December 31, 2015, 30 percent of GTN's total distributable cash flow was $27 million. As a result, $12 million of net income attributable to controlling interests was allocated to the Class B units in 2015. On February 12, 2016, this amount was paid to TransCanada (Refer to Note 13 and 22).

NOTE 13 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.

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.

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 effective 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%

The following table provides information about our distributions (in millions, except per unit distributions amounts).

			Limited Partners		General Partner		
Declaration Date	Payment Date	Per Unit Distribution	Common Units	Class B Units(c)	2%	IDRs(a)	Total Cash Distribution
1/17/2013	2/14/2013	$0.78	$42	$	$1	$	$43
4/23/2013	5/15/2013	$0.78	$42	$	$1	$	$43
7/23/2013	8/14/2013	$0.81	$50	$	$1	$	$51
10/24/2013	11/14/2013	$0.81	$50	$	$1	$	$51
1/16/2014	2/14/2014	$0.81	$50	$	$1	$	$51
4/25/2014	5/15/2014	$0.81	$51	$	$1	$	$52
7/23/2014	8/14/2014	$0.84	$53	$	$1	$	$54
10/23/2014	11/14/2014	$0.84	$53	$	$1	$1	$55
1/22/2015	2/13/2015	$0.84	$54	$	$1	$	$55
4/23/2015	5/15/2015	$0.84	$54	$	$1	$	$55
7/23/2015	8/14/2015	$0.89	$56	$	$2	$1	$59
10/22/2015	11/13/2015	$0.89	$57	$	$1	$1	$59
1/21/2016(b)	2/12/2016(b)	$0.89	$57	$12(d)	$1	$1	$71

(a)
The distributions paid for the year ended December 31, 2015 included incentive distributions to the General Partner of $2 million (2014 $1 million). There were no incentive distributions paid to the General Partner in the year ended December 31, 2013.

(b)
On February 12, 2016, we paid a cash distribution of $0.89 per unit on our outstanding common units to unitholders of record at the close of business on February 2, 2016 (refer to Note 22).

(c)
The Class B units issued by us on April 1, 2015 represent limited partner interests in us and entitle TransCanada to an annual distribution which is an amount based on 30 percent of GTN's annual distributions after achieving certain annual thresholds (refer to Note 6 and 9).

(d)
On February 12, 2016, we paid TransCanada $12 million representing 30 percent of GTN's total distributable cash flows for the nine months ended December 31, 2015 less $15 million (refer to Note 9 and 22).

NOTE 14 CHANGE IN OPERATING WORKING CAPITAL

Year Ended December 31 (millions of dollars)	2015	2014(a)	2013(a)
Change in accounts receivable and other		2	1
Change in accounts payable and accrued liabilities	(3)	4	(9)
Change in accounts payable to affiliates	(10)[(b)]	11	(2)

Year Ended December 31 (millions of dollars)	2015	2014(a)	2013(a)
Change in accrued interest	4		2
Change in operating working capital	(9)	17	(8)

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

(b) Excludes certain non-cash items primarily related to accruals of $10 million for construction of GTN's Carty Lateral and $2 million for costs related to acquisition of 49.9 percent interest in PNGTS (Note 22).

NOTE 15 TRANSACTIONS WITH MAJOR CUSTOMERS

The following table shows revenues from the Partnership's major customers comprising more than 10 percent of the Partnership's total revenues for the years ended December 31, 2015, 2014 and 2013:

Year Ended December 31 (millions of dollars)	2015	2014	2013(a)
Anadarko Energy Services Company (Anadarko)	48	48	48
Pacific Gas and Electric Company (Pacific Gas)	42	45	46

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

At December 31, 2015, Anadarko and Pacific Gas owed the Partnership approximately $4 million and $3 million, respectively, which is greater than 10 percent of our Trade accounts receivable. At December 31, 2014, Anadarko and Pacific Gas each owed the Partnership approximately $4 million, which is greater than 10 percent of our Trade accounts receivable.

NOTE 16 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 $3 million for each of the years ended December 31, 2015, 2014 and 2013.

As operator, TransCanada's subsidiaries provide capital and operating services to GTN, Northern Border, Bison, Great Lakes, 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, 2015, 2014 and 2013 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2015 and 2014 are summarized in the following tables:

Year ended December 31 (millions of dollars)	2015	2014	2013
Capital and operating costs charged by TransCanada's subsidiaries to:			
GTN(a)(b)	30	30	28
Northern Border(a)	36	35	30
Bison(a)(b)(d)	4	6	5
Great Lakes(a)	30	30	31
North Baja	5	5	4
Tuscarora	4	4	4
Impact on the Partnership's net income attributable to controlling interests:			
GTN(b)(c)	25	19	19
Northern Border	14	16	14
Bison(b)(d)	4	4	4
Great Lakes	13	13	14
North Baja	5	4	4
Tuscarora	4	4	4

December 31 (millions of dollars)	2015	2014
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		

December 31 (millions of dollars)	2015	2014
GTN(a)	3	10
Northern Border(a)	5	10
Bison(a)		2
Great Lakes(a)	3	9
North Baja		1
Tuscarora	1	1

(a) Represents 100 percent of the costs.

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

(c) In 2015, the Partnership acquired remaining 30 percent interest in GTN (Refer to Note 6).

(d) In 2014, the Partnership acquired remaining 30 percent interest in Bison (Refer to Note 6).

Great Lakes' earns transportation revenues from TransCanada and its affiliates, some of which are provided at discounted rates and some at maximum recourse rates. Great Lakes earned $125 million of transportation revenues under these contracts in 2015 (2014 $71 million; 2013 $68 million). This amount represents 71 percent of total revenues earned by Great Lakes in 2015 (2014 49 percent; 2013 55 percent). Great Lakes also earned $2 million in affiliated rental revenue in 2015 (2014 $2 million and 2013 $1 million).

Revenue from TransCanada and its affiliates of $59 million is included in the Partnership's equity earnings from Great Lakes in 2015 (2014 $34 million; 2013 $32 million). At December 31, 2015, $17 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (2014 $15 million).

Effective November 1, 2014, Great Lakes executed contracts with an affiliate, ANR Pipeline Company (ANR), to provide firm service in Michigan and Wisconsin. These contracts were at the maximum FERC authorized rate and were intended to replace historical contracts. On December 3, 2014, the FERC accepted and suspended Great Lakes' tariff records to become effective May 3, 2015, subject to refund. On February 2, 2015, FERC issued an Order granting a rehearing and clarification request submitted by Great Lakes, which allowed additional time for FERC to consider Great Lakes' request. Following extensive discussions with numerous shippers and other stakeholders, on April 20, 2015, ANR filed a settlement with FERC that included an agreement by ANR to pay Great Lakes the difference between the historical and maximum rates (ANR Settlement). Great Lakes provided service to ANR under multiple service agreements and rates through May 3, 2015 when Great Lakes' tariff records became effective and subject to refund. Great Lakes deferred an approximate $9 million of revenue related to services performed in 2014 and approximately $14 million of additional revenue related to services performed through May 3, 2015 under such agreements. On October 15, 2015, FERC accepted and approved the ANR Settlement. As a result, Great Lakes recognized the deferred transportation revenue of approximately $23 million in the fourth quarter of 2015.

Bison's former parent, TransCanada, made an equity contribution to Bison of $18 million in the second quarter of 2013. This amount represents the TransCanada's 75 percent share of a $24 million cash call from Bison to repay inter-affiliate debt primarily related to pipeline construction costs, including reclamation and restoration work.

Effective October 1, 2013, GTN and Bison participated in the Partnership's cash management program. Prior to this, GTN and Bison were part of TransCanada's cash management program. This program matches short-term cash surpluses and borrowing requirements of participating subsidiaries, thus minimizing total borrowing from outside sources. Funds advanced under the program are considered to be a loan, accruing interest and repayable on demand. GTN and Bison will receive interest on funds advanced to the Partnership at the rate of interest earned by the Partnership on its short-term cash investments and will pay interest on funds advanced from the Partnership based on the Partnership's short-term borrowing costs. At December 31, 2015 and 2014, GTN and Bison did not have any demand loan receivable from an affiliate or a demand loan payable to an affiliate.

NOTE 17 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2015 and 2014:

Quarter ended (millions of dollars except per common unit amounts)	Mar 31	Jun 30	Sept 30	Dec 31
2015				
Transmission revenues	87	85	83	89
Equity earnings(a)	31	15	17	34
Impairment of equity-method investment(b)				(199)
Net income (loss)	64	44	49	(137)
Net income (loss) attributable to controlling interests	57	44	49	(137)
Net income (loss) per common unit	$0.88	$0.66	$0.70	(2.24)
Cash distribution paid	55	55	59	59
2014				
Transmission revenues	87	82	80	87
Equity earnings(a)	33	18	15	22
Net income	67	45	39	53

Quarter ended (millions of dollars except per common unit amounts)	**Mar 31**	**Jun 30**	**Sept 30**	**Dec 31**
Net income attributable to controlling interests	57	37	31	47
Net income per common unit	$0.90	$0.58	$0.48	$0.71
Cash distributions paid	51	52	54	55

(a)

Equity Earnings represents our share in investee's earnings and does not include any impairment charge on equity method goodwill included as part of the carrying value of our investments in unconsolidated affiliates.

(b)

During the three months ended December 31, 2015, we recognized an impairment charge on our investment in Great Lakes amounting to $199 million. No impairment has been identified on our investment in Northern Border (Refer to Note 4).

NOTE 18 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 carrying value of cash and cash equivalents, accounts receivable and other, accounts payable and accrued liabilities, accounts payable to affiliates, accrued interest and short-term debt 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 fair value of interest rate derivatives is calculated using the income approach which uses period-end market rates and applies a discounted cash flow valuation model.

The estimated fair value of the Partnership's debt as at December 31, 2015 and 2014 are as follows:

	2015		2014	
December 31 (millions of dollars)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Senior Credit Facility due 2017	200	200	330	330
2013 Term Loan Facility due 2018	500	500	500	500
Short-Term Loan Facility due 2015			170	170
2015 Term Loan Facility due 2018	170	170		
4.65% Unsecured Senior Notes due 2021	350	338	350	375
4.375% Unsecured Senior Notes due 2025	349	314		
5.09% Unsecured Senior Notes due 2015			75	76
5.29% Unsecured Senior Notes due 2020	100	108	100	111
5.69% Unsecured Senior Notes due 2035	150	151	150	168
Unsecured Term Loan Facility due 2019	75	75		

	2015		2014	
3.82% Series D Senior Notes due 2017	16	17	20	21
	1,910	1,873	1,695	1,751

Long-term debt is recorded at amortized cost and classified in Level II of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified in 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.

Market risk is the risk that changes in market interest rates may result in fluctuations in the fair values or cash flows of financial instruments. The Partnership's floating rate debt is subject to LIBOR benchmark interest rate risk. The Partnership uses interest rate derivatives to manage its exposure to interest rate risk. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

The Partnership hedged interest payments on $150 million of our $500 million variable-rate 2013 Term Loan Facility with interest rate swaps effective September 3, 2013 and maturing July 1, 2018, at a weighted average fixed interest rate of 2.79 percent. The interest rate swaps are structured such that the cash flows of the derivative instruments match those of the variable rate of interest on the 2013 Term Loan Facility. At December 31, 2015 and 2014, the fair value of the interest rate swaps accounted for as cash flow hedges was a liability of $1 million (both on a gross and net basis) (December 31, 2013 less than $1 million). In 2015, the Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges. The change in fair value of interest rate derivative instruments recognized in other comprehensive income was nil million for the year ended December 31, 2015 (2014 $1 million; 2013 less than $1 million). In 2015, the net realized loss related to the interest rate swaps was $2 million and was included in financial charges and other (2014 $2 million; 2013 $1 million).

The Partnership has no master netting agreements, however, contracts contain provisions with rights of offset. The Partnership has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. Had the Partnership elected to present these instruments on a net basis, there would be no effect on the consolidated balance sheet as of December 31, 2015 and 2014.

Counterparty credit risk represents the financial loss that the Partnership would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Partnership. 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. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 31, 2015, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2015 and 2014, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $35 million.

(c) Other

As discussed more fully in Note 4, we recognized $199 million impairment to our equity investment in Great Lakes during the fourth quarter of 2015, reflected as Impairment of equity-method investment on our Statement of Income for the year ended December 31, 2015. The estimated fair value measurement of this investment is classified as Level 3. In the determination of the fair value, we used an income and market approach based on internal forecasts on expected future cash flows and applied appropriate discount rates. The determination of expected future cash flows involved significant assumptions and estimates regarding revenue, operating and maintenance costs and future growth capital.

NOTE 19 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	2015	2014
Trade accounts receivable, net of allowance of nil	31	30
Accounts receivable from affiliates		1
Other	4	4
	35	35

NOTE 20 REGULATORY MATTERS

North Baja On January 6, 2014, FERC approved North Baja's application to temporarily abandon compression associated with the original design of its pipeline system. This temporary abandonment will preserve replacement options while reducing maintenance requirements and related expenses without any reduction in capacity or impact to existing firm transportation service.

Tuscarora On January 21, 2016, the FERC issued an Order (the January 21 Order) initiating an investigation pursuant to Section 5 of the Natural Gas Act (NGA) to determine whether Tuscarora's existing rates for jurisdictional services are just and reasonable. Tuscarora is currently preparing its response as required by the January 21 Order. We cannot predict the outcome or potential impact of this proceeding to Tuscarora at this time.

NOTE 21 CONTINGENCIES

Employees Retirement System of the City of St. Louis v. TC PipeLines GP, Inc., et al. On October 13, 2015, an alleged unitholder of the Partnership filed a class action and derivative complaint in the Delaware Court of Chancery against the General Partner, TransCanada American Investments, Ltd. (TAIL) and TransCanada, and the Partnership as a nominal defendant. The complaint alleges direct and derivative claims for breach of contract, breach of the duty of good faith and fair dealing, aiding and abetting breach of contract, and tortious interference in connection with the 2015 GTN Acquisition, including the issuance by the Partnership of $95 million in Class B Units and amendments to the Partnership Agreement to provide for the issuance of the Class B Units. Plaintiff seeks, among other things, to enjoin future issuances of Class B Units to TransCanada or any of its subsidiaries, disgorgement of certain distributions to the General Partner, TransCanada and any related entities, return of some or all of the Class B Units to the Partnership, rescission of the amendments to the Partnership Agreement, monetary damages and attorney fees. The Partnership has moved to dismiss the complaint and intends to defend vigorously against the claims asserted.

NOTE 22 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through February 26, 2016, 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 consolidated financial statements other than what is disclosed here and/or those already disclosed in the preceding notes.

On January 21, 2016, the board of directors of our General Partner declared the Partnership's fourth quarter 2015 cash distribution in the amount of $0.89 per common unit. The fourth quarter cash distribution, which was paid on February 12, 2016 to unitholders of record as of February 2, 2016, totaled $59 million and was paid in the following manner: $57 million to common unitholders (including $5 million to the General Partner as holder of 5,797,106 common units and $10 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $2 million to the General Partner in respect of its effective two percent general partner interest, which included IDRs of $1 million.

On January 21, 2016, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $12 million and was paid on February 12, 2016. The Class B distribution represents an amount based upon 30 percent of GTN's distributable cash flow during the nine months ended December 31, 2015 less $15 million.

Northern Border declared its fourth quarter 2015 distribution of $44 million on January 11, 2016, of which the Partnership received its 50 percent share or $22 million. The distribution was paid on February 1, 2016.

Great Lakes declared its fourth quarter 2015 distribution of $42 million on January 11, 2016, of which the Partnership received its 46.45 percent share or $20 million. The distribution was paid on February 1, 2016.

On January 1, 2016, the Partnership acquired a 49.9 percent interest in PNGTS from a subsidiary of TransCanada (PNGTS Acquisition). The total purchase price of the PNGTS Acquisition was $223 million plus preliminary purchase price adjustments of $3 million. The purchase price consisted of $191 million in cash (including the preliminary purchase price adjustment of $3 million) and the assumption of $35 million in proportional PNGTS debt. The Partnership funded the cash portion of the transaction using proceeds received from our ATM program and additional borrowings under our Senior Credit Facility. The purchase agreement provides for additional payments to TransCanada ranging from $5 million up to a total of $50 million if pipeline capacity is expanded to various thresholds during the fifteen year period following the date of closing. The Partnership will account for this acquisition as a transaction between entities under common control (refer to Note 2 Significant accounting policies)

PNGTS is a high-capacity, high-pressure interstate natural gas pipeline which began serving New England's energy needs in March, 1999. The pipeline connects with the TQM at the Canadian border and shares facilities with the Maritimes and Northeast Pipeline from Westbrook, Maine to a connection with the Tennessee Gas Pipeline System near Boston, Massachusetts.

On January 25, 2016, the Partnership hedged interest payments on the remaining $350 million of the $500 million variable-rate 2013 Term Loan Facility with interest rate swaps from January 27, 2016 through July 1, 2018, where the weighted average fixed rate paid is 2.10 percent. The interest rate swaps are structured such that the cash flows of the derivative instruments match those of the variable rate of interest on the 2013 Term Loan Facility.

NORTHERN BORDER PIPELINE COMPANY
INDEPENDENT AUDITORS' REPORT

The Management Committee
Northern Border Pipeline Company:

Report on the Financial Statements

We have audited the accompanying financial statements of Northern Border Pipeline Company (the Company), which comprise the balance sheets as of December 31, 2015 and 2014, and the related statements of income, comprehensive income, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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 from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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, 2015 and 2014, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 16, 2016

NORTHERN BORDER PIPELINE COMPANY

BALANCE SHEETS

December 31, (In thousands)	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27,294	41,386
Accounts receivable	22,511	23,732
Related party receivables	2,339	1,597
Materials and supplies, at cost	5,649	5,539
Prepaid expenses and other	2,594	2,350
Total current assets	60,387	74,604
Property, plant and equipment:		
In service natural gas transmission plant	2,570,220	2,582,570
Construction work in progress	2,803	505
Total property, plant and equipment	2,573,023	2,583,075
Less: Accumulated provision for depreciation and amortization	1,449,033	1,419,998
Property, plant and equipment, net	1,123,990	1,163,077
Other assets:		
Regulatory assets	15,552	32,225
Unamortized debt expense	2,009	1,894
Other	9	9
Total other assets	17,570	34,128
Total assets	$1,201,947	1,271,809
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 100,000	
Accounts payable	7,366	12,140
Related party payables	4,783	9,633
Accrued taxes other than income	19,766	33,907
Accrued interest	6,857	6,874
Other	32	1,081
Total current liabilities	138,804	63,635
Long-term debt	311,231	411,195
Deferred credits and other liabilities		
Regulatory liabilities	21,924	19,652
Other	3,527	2,821
Total deferred credits and other liabilities	25,451	22,473
Total liabilities	475,486	497,303

Partners' equity:		
Partners' capital	**728,279**	776,569
Accumulated other comprehensive loss	**(1,818)**	(2,063)
Total partners' equity	**726,461**	774,506
Total liabilities and partners' equity	**$1,201,947**	1,271,809

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

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF INCOME

Years ended December 31, (In thousands)	**2015**	2014	2013
Operating revenue	**$285,510**	293,318	285,849
Operating expenses:			
Operations and maintenance	**47,260**	48,720	51,710
Depreciation and amortization	**59,571**	58,752	58,231
Taxes other than income	**22,826**	23,383	23,052
Operating expenses	**129,657**	130,855	132,993
Operating income	**155,853**	162,463	152,856
Interest expense:			
Interest expense	**26,591**	26,565	27,286
Interest expense capitalized	**(76)**	(53)	(90)
Interest expense, net	**26,515**	26,512	27,196
Other income (expense):			
Allowance for equity funds used during construction	**243**	176	289
Other income	**4,722**	3,605	4,176
Other expense	**(420)**	(95)	(32)
Other income, net	**4,545**	3,686	4,433
Net income to partners	**$133,883**	139,637	130,093

NORTHERN BORDER PIPELINE COMPANY

STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, (In thousands)	**2015**	2014	2013
Net income to partners	**$133,883**	139,637	130,093
Other comprehensive income:			
Changes associated with hedging transactions	**245**	228	212
Total comprehensive income	**$134,128**	139,865	130,305

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)		2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income to partners	$	133,883	139,637	130,093
Adjustments to reconcile net income to partners to net cash provided by operating activities:				
Depreciation and amortization		59,571	58,752	58,263
Allowance for equity funds used during construction		(243)	(176)	(289)
Changes in components of working capital		(7,644)	6,135	(470)
Other		1,843	583	729
Total adjustments		53,527	65,294	58,233
Net cash provided by operating activities		187,410	204,931	188,326
CASH FLOWS USED IN INVESTING ACTIVITIES:				
Capital expenditures for property, plant and equipment, net		(15,348)	(21,012)	(20,683)
Other		(3,417)	5,773	(542)
Net cash used in investing activities		(18,765)	(15,239)	(21,225)
CASH FLOWS USED IN FINANCING ACTIVITIES:				
Equity contributions from partners				61,500
Distributions to partners		(182,173)	(174,966)	(168,832)
Proceeds from issuance of debt		10,000	23,000	45,000
Repayment of debt		(10,000)	(23,000)	(106,500)
Debt issuance costs		(564)		
Net cash used in financing activities		(182,737)	(174,966)	(168,832)
Net change in cash and cash equivalents		(14,092)	14,726	(1,731)
Cash and cash equivalents at beginning of year		41,386	26,660	28,391
Cash and cash equivalents at end of year	$	27,294	41,386	26,660
Supplemental disclosure for cash flow information:				
Cash paid for interest, net of amount capitalized	$	25,802	25,881	26,510
Accruals for property, plant and equipment		1,841		
Changes in components of working capital:				
Accounts receivable	$	1,220	1,140	1,651
Related party receivables		(742)	141	(1,246)
Materials and supplies		(109)	(70)	(181)
Prepaid expenses and other		(118)	(152)	179
Accounts payable		(1,183)	(103)	(788)
Related party payables		(6,507)	6,596	(551)
Accrued taxes other than income		(188)	(173)	(960)
Accrued interest		(17)	(75)	17
Other current liabilities			(1,169)	1,409
Total	$	(7,644)	6,135	(470)

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, 2012	$394,569	$394,568	$(2,503)	$786,634
Net income to partners	65,046	65,047		130,093
Changes associated with hedging transactions			212	212
Equity contributions received	30,750	30,750		61,500
Distributions paid	(84,416)	(84,416)		(168,832)
Partners' equity at December 31, 2013	$405,949	$405,949	$(2,291)	$809,607
Net income to partners	69,818	69,819		139,637
Changes associated with hedging transactions			228	228
Distributions paid	(87,483)	(87,483)		(174,966)
Partners' equity at December 31, 2014	$388,284	$388,285	$(2,063)	$774,506
Net income to partners	66,941	66,942		133,883
Changes associated with hedging transactions			245	245
Distributions paid	(91,086)	(91,087)		(182,173)
Partners' equity at December 31, 2015	$364,139	$364,140	$(1,818)	$726,461

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

NORTHERN BORDER PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

Northern Border Pipeline Company (the Partnership) is a Texas general partnership formed in 1978. The Partnership owns a 1,260-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 partners and ownership percentages at December 31, 2015 and 2014 were as follows:

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

The Partnership is 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 the financial statements in accordance with U.S. generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities during the reported period. Although management believes these estimates are reasonable, actual results could differ from these estimates in the financial statements and accompanying notes.

(b) Cash and Cash Equivalents

The Partnership's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

(c) 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, 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 in 2015 and 2014 were not material to the Partnership's financial statements.

(d) 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 interconnecting parties 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 and related party receivables. Imbalances owed to others are reported on the balance sheets as trade accounts payable and accounts payable to affiliates. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(e) 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.

(f) 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 of 1938 and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board 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. The Partnership evaluates the continued applicability of regulatory accounting, considering such factors as regulatory charges, the impact of competition, and the ability to recover regulatory assets as set forth in ASC 980. 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 regulatory assets and liabilities at December 31, 2015 and 2014:

	December 31, 2015	December 31, 2014	Remaining recovery/ settlement period
	(In thousands)		*(Years)*
Regulatory Assets			
Fort Peck lease option	$ 12,784	$ 13,102	35
Pipeline extension project	2,768	3,229	6
Volumetric fuel tracker		1,582	(a)
South Dakota use tax assessment		14,312	(b)
Compressor usage surcharge	125		(c)
	15,677	32,225	
Less: Current portion included in Prepaid expenses and other	125		
	$ 15,552	$ 32,225	
Regulatory Liabilities			
Negative salvage	$ 21,924	$ 19,652	(d)
Compressor usage surcharge		1,081	(c)
Volumetric fuel tracker	32		(a)
	21,956	20,733	
Less: Current portion included in Other	32	1,081	
	$ 21,924	$ 19,652	

(a) Volumetric fuel tracker assets or liabilities are settled with in-kind exchanges with customers continually

(b)

South Dakota use tax assessment surrounding legal proceedings (refer to Note 4(a))

(c)

Compressor usage surcharge is designed to track the recovery of the actual costs related to both electricity usage at the Partnership's electric compressors and compressor fuel use taxes imposed on the consumption of natural gas powered stations along the Partnership's pipeline system (refer to Note 4(b))

(d)

Negative salvage accrued for estimated net costs of removal of transmission plant has a settlement period related to the estimated life of the assets (refer to Note 2(g))

(g) Property, Plant and Equipment

Property, plant and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs, 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, are capitalized. 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 depreciation rates approved in the Partnership's last rate proceeding. Currently, the Partnership's depreciation rates vary from 2.02% to 20% per year. Using these rates, the remaining depreciable life of these assets ranges from 2 to 39 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.

(h) 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.

(i) Revenue Recognition

The Partnership's revenues are primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For the Partnership's transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. For the Partnership's 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 provision for these potential refunds. As of December 31, 2015 and 2014, there are no provisions reflected in these financial statements.

(j) Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. 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. 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 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. The Partnership has determined that asset retirement obligations exist for certain of its 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.

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, 2015 and 2014. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(k) Derivative 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 the 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 derivatives 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) 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.

The Partnership amortizes premiums, discounts, and expenses incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

(m) Operating Leases

The Partnership has non-cancelable operating leases for office space and rights-of-way. The Partnership records rent expense straight-line over the life of the lease.

(n) 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.

(o) Income Taxes

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

(p) Fair Value

For cash and cash equivalents, receivables, accounts payable and certain accrued expenses, the carrying amount approximates fair value due to the short maturities of these instruments. For long-term debt instruments, fair value is estimated based upon market values (if applicable) or on the current interest rates available to us for debt with similar terms and remaining maturities. Considerable judgment is required in developing these estimates.

3. FUTURE ACCOUNTING CHANGES

Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09 "Revenue from Contracts with Customers (Topic 606)." This guidance supersedes the revenue recognition requirements in Topic 605, Revenue Recognition and most industry-specific guidance. This new guidance requires that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. On July 9, 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also voted to permit early adoption of the standard, but not before the original effective date of December 15, 2016. This new guidance, once effective, allows two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. The Partnership is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its financial statements.

Imputation of interest

In April 2015, the FASB issued ASU No. 2015-03 "Interest Imputation of Interest (Subtopic 835-30)," an amendment of previously issued guidance on imputation of interest. This updated guidance requires debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount or premiums. The recognition and measurement for debt issuance costs would not be affected. This guidance is effective from January 1, 2016 and early application is permitted. This guidance should be adopted on a retrospective basis, wherein the balance sheet of each individual period presented would be adjusted to reflect the period-specific effects of applying the new guidance. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in Other assets to an offset of their respective debt liabilities.

4. COMMITMENTS AND CONTINGENCIES

(a) Legal Proceedings

State of South Dakota Use Tax Appeal On February 28, 2011, the State of South Dakota assessed a use tax in the amount of approximately $6 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. In November 2011, Northern Border filed a Request for Hearing with the South Dakota Department of Revenue to protest the assessment. A hearing was held on the matter in May 2012 and in the third quarter of 2013, the South Dakota Department of Revenue determined that the gas used by Northern Border to fuel compressors is taxable. In October 2013, Northern Border filed an appeal of this decision in the South Dakota Circuit Court, Sixth Judicial Circuit (Circuit Court). In May 2014, the Circuit Court issued a Memorandum Decision reversing the Final Decision of the South Dakota Department of Revenue. The Circuit Court found that the compression of natural gas and the natural gas burned in that process is a function of natural gas transportation and therefore exempt from use tax. The South Dakota Department of Revenue filed an appeal to the Circuit Court decision on July 23, 2014. Briefs were submitted to the South Dakota Supreme Court and oral argument was held on March 24, 2015. On August 5, 2015, the South Dakota Supreme Court issued its decision in Northern Border Pipeline v. South Dakota Department of Revenue, ruling that the South Dakota Department of Revenue could not assess use tax on gas burned in compressors on Northern Border's pipeline located in South Dakota because Northern Border did not own the gas. The opinion affirmed the Circuit Court's reversal of the use tax assessment by the Department of Revenue and resulted in the reversal of the $15.5 million recorded liability and the related deferred asset with no impact to the Partnership's earnings.

(b) Regulatory Matters

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, 2013, the Partnership implemented new rates as a result of its Stipulation and Agreement of Settlement. The settlement includes a three-year moratorium on rate changes and requires the Partnership to file for new rates no later than January 1, 2018. The settlement establishes maximum long-term transportation rates on the Partnership's system and current transportation rates will be reduced by approximately 11 percent. In addition, the composite depreciation rate was reduced to 2.19 percent from 2.40 percent, which prospectively increases the depreciable life of the Partnership's assets.

The compressor usage surcharge is designated to recover the actual costs of electricity at the Partnership's electric compressors and any compressor fuel use taxes imposed on its 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, 2015 and 2014, the Partnership had recorded $0.1 million as prepaid expenses and other and $1.1 million as other current liabilities, respectively, on the accompanying balance sheets for the net under and over recoveries of compressor usage related costs.

(c) Operating Leases

The Partnership makes lease payments under non-cancelable operating leases on office space and rights-of-way. The Partnership's rent expense incurred was $3.0 million, $3.0 million, and $2.9 million for the years ended December 31, 2015, 2014, and 2013, respectively. The Partnership's future minimum lease payments are as follows:

Year ending December 31, (In thousands)	
2016	2,561
2017	2,554
2018	2,554
2019	2,433
2020	2,190
Thereafter	44,459
	$ 56,751

In August 2004, the Partnership 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 the Partnership, 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 the Partnership. In consideration of this option and other benefits, the Partnership paid a lump sum amount of $7.4 million and made additional annual option payments through March 31, 2011.

5. CREDIT FACILITIES AND LONG-TERM DEBT

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

December 31, (In thousands)	2015	2014
2011 Credit Agreement average interest rate of 1.735% at December 31, 2015 due 2020	$ 61,500	$ 61,500
2009 Senior Notes 6.24%, due 2016	100,000	100,000
2001 Senior Notes 7.50%, due 2021	250,000	250,000
Unamortized debt discount	(269)	(305)
	411,231	411,195
Less: Current portion	100,000	
	$ 311,231	$ 411,195

On November 16, 2011, the Partnership 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 Partnership's $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. On October 8, 2015 the Partnership closed on the renewal and first extension of the 2011 Credit Agreement that was to expire on November 16, 2016 for an additional five years, maturing on October 9, 2020.

At December 31, 2015, the Partnership's outstanding borrowings under the 2011 Credit Agreement were $61.5 million, leaving $138.5 million available for future borrowing. The Partnership may, at its option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under its 2011 Credit Agreement by an aggregate amount not to exceed $300 million, provided that lenders are willing to commit additional amounts. At the Partnership's 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 its long-term unsecured credit ratings. The 2011 Credit Agreement permits the Partnership to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. The Partnership is required to pay a commitment fee based its credit rating and on the unused principal amount of the commitment of $200 million.

Certain of the Partnership's long-term debt arrangements contain covenants that restrict the incurrence of secured indebtedness or liens upon property by the Partnership. Under the 2011 Credit Agreement, the Partnership is required to comply with certain financial, operational and legal covenants. Among other things, the Partnership is 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, the Partnership 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, 2015, the Partnership was in compliance with all of its financial covenants.

Aggregate required repayment of long-term debt for the next five years is $411.5 million, with $100 million due in 2016 and $61.5 million due in 2020. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2017, 2018, or 2019.

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Prior to December 31, 2001, the Partnership terminated a series of interest rate derivatives in exchange for cash. These derivatives had previously been accounted for as hedges with $4.1 million recorded in accumulated other comprehensive loss (AOCL) as of the termination date. The previously recorded AOCL is currently being amortized under the effective interest method over the remaining term of the related hedged instrument, the Partnership's 2001 Senior Notes due 2021.

During the three-year period ended December 31, 2015, the Partnership reclassified the below amounts from AOCL into earnings for these terminated derivatives.

		Years Ended December 31,		
Net Loss Reclassified from AOCL into Income (Effective Portion) ***(In thousands)***	**Statements of Income Caption**	**2015**	**2014**	**2013**
Cash flow hedges	Interest expense	**$ (245)**	$ (228)	**$ (212)**

At December 31, 2015 and 2014 Accumulated AOCL was $1.8 million and $2.1 million, respectively, which will be amortized through 2021 as noted above. The Partnership expects to reclassify $0.3 million from AOCL as an increase to interest expense in 2015. The Partnership had no other derivative instruments during the period ended December 31, 2015.

7. FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurement*, 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 at December 31, 2015 and 2014. 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.

	2015		2014	
(In thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial asset:				
Cash and cash equivalents	$27,294	$27,294	$41,386	$41,386
Financial liability:				
Long-term debt	$411,500	$425,626	$411,500	$475,617

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 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 2001 and 2009 Senior Notes, which will result in no gains or losses on its repayment. The fair value of the 2011 Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

(c) Other Recurring Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of other items measured and recorded at fair value on a recurring basis as of December 31, 2015 and 2014:

	2015		2014	
(In thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Natural gas imbalance asset	$135	$135	$	$
Related party natural gas imbalance asset	$228	$228	$60	$60
Natural gas imbalance liability	$819	$819	$1,993	$1,993

Natural Gas Imbalances Natural gas imbalances represent the difference between the amount of natural gas delivered to or received from a pipeline system and the amount of natural gas scheduled to be delivered or received at current market prices. The Partnership values these imbalances by applying the difference between the measured quantities of natural gas delivered to or received from its shippers and operators to the current average of the Northern Ventura index price and the Chicago city-gates index price. The Partnership has classified the fair value of natural gas imbalances as a Level 2 in the "Fair Value Hierarchy," as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance.

8. TRANSACTIONS WITH MAJOR CUSTOMERS

For the year ended December 31, 2015, shippers providing significant operating revenues to the Partnership were BP Canada and Sequent Energy Management with revenues of $26.2 million and $24.7 million, respectively.

For the year ended December 31, 2014, shippers providing significant operating revenues to the Partnership were BP Canada and Tenaska Marketing Ventures with revenues of $24.9 million and $23.4 million, respectively.

For the year ended December 31, 2013, shippers providing significant operating revenues to the Partnership were Tenaska Marketing Ventures and BP Canada with revenues of $28.8 million and $23.9 million, respectively.

9. TRANSACTIONS WITH RELATED PARTIES

The day-to-day management of the Partnership's affairs is the responsibility of TransCanada Northern Border, Inc., (TransCanada Northern Border) pursuant to an operating agreement between TransCanada Northern Border and the Partnership effective April 1, 2007. TransCanada Northern Border utilizes the services of TransCanada Corporation (TransCanada) and its affiliates for management services related to the Partnership. The Partnership is charged for the salaries, benefits and expenses of TransCanada and its affiliates attributable to the Partnership's operations. For the years ended December 31, 2015, 2014, and 2013, the Partnership's charges from TransCanada and its affiliates totaled approximately $36.4 million, $35.1 million, and $29.6 million, respectively. At December 31, 2015 and 2014, the Partnership owed $4.8 million and $9.6 million, respectively, to these affiliates classified as related party payables on the balance sheets.

For the years ended December 31, 2015, 2014, and 2013, the Partnership had contracted firm capacity held by one shipper affiliated with one of the Partnership's general partners. Revenues from ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), a subsidiary of ONEOK, for 2015, 2014, and 2013 were $22.6 million, $11.1 million, and $8.1 million, respectively. At December 31, 2015 and 2014, the Partnership had outstanding receivables from ONEOK Rockies of $2.1 million and $1.5 million, respectively.

10. CASH DISTRIBUTION AND CONTRIBUTION POLICY

The Partnership's General Partnership Agreement provides that distributions to its partners are to be made on a pro rata basis according to each partner's capital account balance. The Partnership's Management Committee determines the amount and timing of the distributions to its 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, the Partnership's cash distribution policy requires the unanimous approval of the Management Committee. The Partnership's cash distributions are equal to 100 percent of its distributable cash flow as determined from its financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures.

For the years ended December 31, 2015, 2014, and 2013, the Partnership paid distributions to its general partners of $182.2 million, $175.0 million, and $168.8 million, respectively. In 2013, the Partnership received contributions from its general partners of $61.5 million, which were used to repay outstanding indebtedness.

11. SUBSEQUENT EVENTS

The Partnership makes distributions to its general partners approximately one month following the end of the quarter. A cash distribution of approximately $43.8 million was declared on January 11, 2016 and paid on February 1, 2016 for the fourth quarter of 2015.

Subsequent events have been assessed through February 16, 2016, 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.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
Independent Auditors' Report

The Partners and the Management Committee
Great Lakes Gas Transmission Limited Partnership:

Report on the Financial Statements

We have audited the accompanying financial statements of Great Lakes Gas Transmission Limited Partnership (the Partnership), which comprise the balance sheets as of December 31, 2015 and 2014, and the related statements of income and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2015, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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 from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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, 2015 and 2014, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 16, 2016

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

BALANCE SHEETS

December 31, (In thousands)	**2015**	2014
Assets		
Current assets:		
Cash and cash equivalents	**$ 48**	$ 37
Demand loan receivable from affiliate	**51,072**	30,402
Accounts receivable:		
Trade	**5,230**	9,652
Affiliates	**16,869**	14,638
Materials and supplies	**10,614**	10,635
Other	**2,144**	1,016
Total current assets	**85,977**	66,380
Property, plant, and equipment:		
Property, plant, and equipment	**2,076,414**	2,074,859
Construction work in progress	**3,385**	794
	2,079,799	2,075,653
Less accumulated depreciation and amortization	**(1,352,605)**	(1,328,100)
Total property, plant, and equipment, net	**727,194**	747,553
Other noncurrent assets	**370**	416
Total assets	**$ 813,541**	814,349
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable:		
Trade	**$ 12,523**	3,777
Affiliates	**4,244**	9,714
Current maturities of long-term debt	**19,000**	19,000
Deferred Revenue		9,432
Taxes payable (other than income)	**7,720**	7,254
Accrued interest	**6,859**	7,112
Other	**9**	369
Total current liabilities	**50,355**	56,658
Long-term debt, net of current maturities	**278,000**	297,000
Other noncurrent liabilities	**235**	245
Partners' capital	**484,951**	460,446
Total liabilities and partners' capital	**$ 813,541**	814,349

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

STATEMENTS OF INCOME AND PARTNERS' CAPITAL

Years ended December 31, (In thousands)	**2015**	2014	2013
Operating revenues	**$176,901**	145,667	124,480
Operating expenses:			
Operation and maintenance	**49,222**	42,399	44,493
Depreciation and amortization	**27,756**	27,736	30,980
Taxes, other than income	**10,637**	10,774	15,924
Total operating expenses	**87,615**	80,909	91,397
Operating income	**89,286**	64,758	33,083
Other income, net	**1,511**	881	141
Interest and debt expense	**(23,946)**	(25,424)	(26,930)
Affiliated interest income	**54**	30	21
Net income	**$ 66,905**	40,245	6,315
Partners' capital:			
Balance at beginning of year	**$460,446**	459,601	470,486
Net income	**66,905**	40,245	6,315
Distributions to partners	**(61,400)**	(58,400)	(36,200)
Contributions from partners	**19,000**	19,000	19,000
Balance at end of year	**$484,951**	460,446	459,601

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

STATEMENTS OF CASH FLOWS

Years ended December 31, (In thousands)	**2015**	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$ 66,905**	$ 40,245	$ 6,315
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**27,756**	27,736	30,980
Allowance for funds used during construction, equity	**(78)**	(46)	(66)
Asset and liability changes:			
Accounts receivable	**2,191**	(7,548)	(188)
Other current assets	**(1,107)**	1,135	108
Noncurrent assets	**46**	45	46
Accounts payable	**959**	5,011	383
Other current liabilities	**(9,579)**	4,435	(3,666)
Noncurrent liabilities	**(10)**	(9)	(42)
Net cash provided by operating activities	**87,083**	71,004	33,870
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property, plant, and equipment	**(7,265)**	(3,400)	(2,940)
Net change in demand loan receivable from affiliate	**(20,670)**	(8,473)	4,545
Other	**2,263**	(742)	742
Net cash provided by (used in) investing activities	**(25,672)**	(12,615)	2,347
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(19,000)
Distributions to partners	**(61,400)**	(58,400)	(36,200)
Contributions from partners	**19,000**	19,000	19,000
Net cash used in financing activities	**(61,400)**	(58,400)	(36,200)
Net change in cash and cash equivalents	**11**	(11)	17
Cash and cash equivalents at beginning of year	**37**	48	31
Cash and cash equivalents at end of year	**$ 48**	$ 37	$ 48
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$ 24,153**	$ 25,691	$ 27,196

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO FINANCIAL STATEMENTS

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, 2015 and 2014 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 28.03% interest as of December 31, 2015.

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) 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.

(c) 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 of 1938 (NGA) and the Natural Gas Policy Act of 1978. Financial Accounting Standards Board 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, 2015 and 2014, there are no significant regulatory assets or liabilities reflected in these financial statements.

(d) 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, 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 charged to the allowance in 2015 and 2014 were not material to the Partnership's financial statements.

(e) 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.

(f) 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.

(g) 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 are also capitalized. 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 November 1, 2013 under a rate settlement approved by the FERC on November 14, 2013, the substantial portion of the Partnership's principal operating assets are being depreciated at an annual rate of 1.28%. 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 1 to 45 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.

(h) 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.

(i) Revenue Recognition

The Partnership's revenues are primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For the Partnership's transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. For interruptible or volumetric-based services, the Partnership records revenues when physical deliveries of natural gas 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. The Partnership was not engaged in a rate proceeding at December 31, 2015 or 2014 and as such there are no allowances reflected in these financial statements.

(j) Commitments and Contingencies

Accounting for Asset Retirement Obligations

The Partnership accounts for asset retirement obligations pursuant to the provisions of ASC 410-20, *Asset Retirement Obligations*. 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. 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, 2015 and 2014. 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.

(k) Income Taxes

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

3. Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09 *Revenue from Contracts with Customers* (Topic 606). This guidance supersedes the revenue recognition requirements in Topic 605, Revenue Recognition and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the FASB deferred the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also voted to permit early adoption of the standard, but not before the original effective date of December 15, 2016. This new guidance, once effective, allows two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. The Partnership is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its financial statements.

Imputation of Interest

In April 2015, the FASB issued ASU No. 2015-03 *Interest Imputation of Interest* (Subtopic 835-30), an amendment of previously issued guidance on imputation of interest. This updated guidance requires debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. The recognition and measurement for debt issuance costs would not be affected. This guidance is effective from January 1, 2016 and will be applied retrospectively. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in Other Noncurrent Assets to an offset of their respective debt liabilities.

4. Commitments and Contingencies

(a) Legal Proceedings

On October 29, 2009, the Partnership filed suit in the U.S. District Court, District of Minnesota, against Essar Minnesota LLC and certain Essar affiliates (collectively, Essar) for breach of its monthly payment obligation under its transportation services agreement with the Partnership. The Partnership sought to recover approximately $33 million for past and future payments due under the agreement. During the first quarter of 2013, the Federal District Court ruled favorably on a summary judgment motion for the Partnership and dismissed Essar's defenses. In

July 2013, the Essar Defendants made an offer of judgment to the Partnership narrowing the issue for trial to the appropriate discount rate on the damages. On October 10, 2014, the District Court issued an Order striking Essar's discount rate expert. Trial on damages was scheduled for October 27, 2014; however, Essar objected to the jurisdiction of the District Court and filed a motion to dismiss the case. On May 4, 2015, the U.S. District Court, District of Minnesota, denied Essar's motion to dismiss for lack of subject matter jurisdiction and set the case for trial in August 2015. Following the trial of the matter, on September 16, 2015, the federal district court judge entered an order in the amount of $32.9 million in favor of the Partnership. On September 20, 2015, Essar appealed the order to the 8th Circuit Court of Appeals.

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, 2015.

(b) Regulatory Matters

On November 14, 2013, the FERC approved a settlement the Partnership made with its customers to modify its transportation rates effective November 1, 2013. The settlement establishes maximum recourse transportation rates that are approximately 21% higher than pre-settlement rates. The settlement requires that the Partnership file to have new rates in effect no later than January 1, 2018.

Effective November 1, 2014, the Partnership executed contracts with an affiliate, ANR Pipeline Company (ANR), to provide firm service in Michigan and Wisconsin. These contracts were at the maximum FERC authorized rate and were intended to replace historical contracts. On December 3, 2014, the FERC accepted and suspended the Partnership's tariff records to become effective May 3, 2015, subject to refund. On February 2, 2015, FERC issued an Order granting a rehearing and clarification request submitted by the Partnership, which allowed additional time for FERC to consider the Partnership's request. Following extensive discussions with numerous shippers and other stakeholders, on April 20, 2015, ANR filed a settlement with FERC that included an agreement by ANR to pay the Partnership the difference between the historical and maximum rates (ANR Settlement). The Partnership provided service to ANR under multiple service agreements and rates through May 3, 2015 when the Partnership's tariff records became effective and subject to refund. The Partnership deferred approximately $9.4 million of revenue related to services performed in 2014 and approximately $13.9 million of additional revenue related to services performed through May 3, 2015 under such agreements. On October 15, 2015, FERC accepted and approved the ANR Settlement. As a result, the Partnership recognized the deferred transportation revenue of approximately $23.3 million in the fourth quarter of 2015.

(c) Other Commercial Commitments

The Partnership has 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. Certain arrangements with the Native American groups expire in 2018 and the Partnership has begun to engage in the renewal process of these agreements.

5. Long-Term Debt

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

(In thousands)	2015	2014
6.73% series Senior Notes due 2016 to 2018	$27,000	36,000
9.09% series Senior Notes due 2016 to 2021	60,000	70,000
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
	297,000	316,000
Less current maturities	19,000	19,000
Total long-term debt less current maturities	$278,000	297,000

The aggregate annual required repayment of long-term debt is $19.0 million for each year from 2016 through 2018 and $21.0 million for each year 2019 and 2020. Aggregate required repayments of long-term debt thereafter total $198.0 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 $160.0 million of partners' capital was restricted as to distributions as of December 31, 2015. As of December 31, 2015, 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 ASC 820, *Fair Value Measurement*, 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 at December 31, 2015 and 2014. 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.

	2015		2014	
(In thousands)	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:				
Cash and cash equivalents	$48	48	37	37
Demand loan receivable	51,072	51,072	30,402	30,402
Financial liabilities:				
Long-term debt	$297,000	361,579	316,000	408,941

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.

Demand loan receivable   The carrying amount of the demand loan receivable 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.

(c) Other Recurring Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of other items measured and recorded at fair value on a recurring basis as of December 31, 2015 and 2014:

	2015		2014	
(In thousands)	Carrying amount	Fair value	Carrying amount	Fair value
Affiliate natural gas imbalance asset	$1,510	1,510	435	435
Natural gas imbalance asset	$420	420	3,699	3,699
Affiliate natural gas imbalance liability	$1,104	1,104	853	853
Natural gas imbalance liability	$1,546	1,546	2,471	2,471

Natural Gas Imbalances   Natural gas imbalances represent the difference between the amount of natural gas delivered to or received from a pipeline system and the amount of natural gas scheduled to be delivered or received at current market prices. We value these imbalances by applying the difference between the measured quantities of natural gas delivered to or received from our shippers and operators to the current Emerson Viking GL index price. We have classified the fair value of natural gas imbalances as a Level 2 in the "Fair Value Hierarchy", as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance.

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, 2015 and 2014, the Partnership had a demand loan receivable from TransCanada of $51.1 million and $30.4 million, respectively.

(b) Affiliate Revenues and Expenses

The Partnership earns transportation revenues from TransCanada and its affiliates under contracts, which provide both discounted and maximum recourse rates. The contracts are on the same terms as would be available to other shippers and the substantial majority of the Partnerships' affiliated revenue is derived from short term contracts with minor contracted volumes extending through 2032.

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)	2015	2014	2013
Transportation revenues from affiliates	$125,296	71,414	68,115
Rental revenue from affiliates	1,803	1,947	1,348
Costs charged from affiliates	30,022	29,722	31,273

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, AFUDC less capital expenditures and debt repayments not funded with cash calls to its partners. 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.

On January 11, 2016, the Management Committee of the Partnership declared a cash distribution in the amount of $42.2 million to the partners. The distribution was paid on February 1, 2016.

9. Subsequent Events

Subsequent events have been assessed through February 16, 2016, 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.

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