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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF1934**

For the fiscal year ended December 31, 2017

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 ☒ 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 ☒

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 ☒ 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 ☒ 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. ☒

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," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒	Accelerated filer o	Non-accelerated filer o (Do not check if a small reporting company)	Smaller Reporting Company o Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2017 was approximately $2.9 billion.

As of February 22, 2018, there were 71,306,396 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 as amended on September 29, 2017
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 as amended on September 29, 2017
2016 PNGTS Acquisition	Partnership's acquisition of a 49.9 percent interest in PNGTS, effective January 1, 2016
2017 Acquisition	Partnership's acquisition of an additional 11.81 percent interest in PNGTS and 49.34 percent in Iroquois on June 1, 2017
2017 Great Lakes Settlement	Stipulation and Agreement of Settlement for Great Lakes regarding its rates and terms and conditions of service approved by FERC on February 22, 2018
2017 Northern Border Settlement	Stipulation and Agreement of Settlement for Northern Border regarding its rates and terms and conditions of service approved by FERC on February 23, 2018
2017 Tax Act	H.R.1, originally known as the Tax Cuts and Jobs Act, enacted on December 22, 2017.
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
C2C Contracts	PNGTS' Continent-to-Coast Contracts with several shippers for a term of 15 years for approximately 82,000 Dth/day
Canadian Mainline	TransCanada's Mainline, a natural gas transmission system extending from the Alberta/Saskatchewan border east to Quebec
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, Tuscarora and PNGTS
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
Joint Facilities	Pipeline facilities jointly owned with MNE on PNGTS
KPMG	KPMG LLP
LDCs	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
MNE	Maritimes and Northeast Pipeline LLC, a subsidiary of Enbridge Inc.
MNOC	M&N Operating Company, LLC, a wholly owned subsidiary of MNE
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, PNGTS and Iroquois
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
PXP	Portland XPress Project
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP's senior facility under revolving credit agreement as amended and restated, dated September 29, 2017
TQM	TransQuebec and Maritimes Pipeline
TransCanada	TransCanada Corporation and its subsidiaries
TransCanada PXP Expenditures	TransCanada's latest estimate of $107 million of upstream capacity capital expenditures that PNGTS may be responsible for in the event the Portland Express Project does not proceed.
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora Settlement	Stipulation and Agreement of Settlement for Tuscarora regarding its rates and terms and conditions of service approved by FERC on September 22, 2016
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), Portland Natural Gas Transmission System (PNGTS) and Iroquois Gas Transmission System, LP (Iroquois).

PART I

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

This report includes certain forward-looking statements. 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, dropdown opportunities, 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;
- the impact of the 2017 Tax Act enacted on December 22, 2017 on our future operating performance;
- other potential changes in the taxation of master limited partnership (MLP) investments by state or federal governments such as 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), U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT);
- the impact of downward changes 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 including management of cybersecurity threats, acts of terrorism and related distractions;

- the expected impact of future accounting changes, commitments and contingent liabilities (if any);
- the impact of any impairment charges;
- changes in the political environment;
- operating hazards, casualty losses and other matters beyond our control;
- the overall increase in the allocated management and operational expenses to our pipeline systems for services performed by TransCanada; 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." 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 publicly traded Delaware master limited partnership. Our common units trade 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. At December 31, 2017, subsidiaries of TransCanada own approximately 24.2 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

Cash Distribution – Our annual cash distribution declared per common unit increased by six percent from $3.71 per common unit in 2016 to $3.94 per common unit in 2017.

On April 25, 2017, the board of directors of our General Partner declared the Partnership's first quarter 2017 cash distribution in the amount of $0.94 per common unit, payable on May 15, 2017 to unitholders of record as of May 5, 2017. The declared distribution totaled $68 million and was paid in the following manner: $65 million to common unitholders (including $5 million to the General Partner as a holder of 5,797,106 common units and $11 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $3 million to our General Partner, which included $1 million for its effective two percent general partner interest and $2 million in respect of its IDRs.

On July 20, 2017, the board of directors of our General Partner declared the Partnership's second quarter 2017 cash distribution in the amount of $1.00 per common unit, payable on August 11, 2017 to unitholders of record as of August 1, 2017. The declared distribution totaled $74 million and was paid in the following manner: $69 million to common unitholders (including $6 million to the General Partner as a holder of 5,797,106 common units and $11 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $5 million to our General

Partner, which included $2 million for its effective two percent general partner interest and $3 million in respect of its IDRs.

On October 24, 2017, the board of directors of our General Partner declared the Partnership's third quarter 2017 cash distribution in the amount of $1.00 per common unit, payable on November 14, 2017 to unitholders of record as of November 3, 2017. The declared distribution totaled $74 million and was paid in the following manner: $70 million to common unitholders (including $6 million to the General Partner as a holder of 5,797,106 common units and $11 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $4 million to our General Partner, which included $1 million for its effective two percent general partner interest and $3 million in respect of its IDRs.

On January 23, 2018, the board of directors of our General Partner declared the Partnership's fourth quarter 2017 cash distribution in the amount of $1.00 per common unit payable on February 13, 2018 to unitholders of record as of February 2, 2018. This declared distribution to our General Partner included a $2 million distribution for its effective two percent general partner interest and an IDR payment of $3 million for a total distribution of $5 million.

Incentive distributions are paid to our General Partner if quarterly cash distributions on the common units exceed levels specified in the Third Amended and Restated Agreement of Limited Partnership of the Partnership (as amended, the Partnership Agreement). The Partnership paid a total of $10 million in respect of the IDRs to our General Partner on the distributions declared from the first to the fourth quarter of 2017. See Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cash Distribution Policy of the Partnership" for further information regarding the Partnership's distributions.

Pipeline updates

Great Lakes Contracting and Settlement – On April 24, 2017, Great Lakes reached an agreement on the terms of a new long-term transportation capacity contract with its affiliate, TransCanada. The contract, which was subject to Canada's National Energy Board (NEB) approval, is for a term of 10 years and allows TransCanada the ability to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system from the Manitoba/U.S. border to the U.S. border near Dawn Ontario. On September 21, 2017, TransCanada received approval from the NEB and as a result, the contract commenced on November 1, 2017. The contract contains volume reduction options up to full contract quantity beginning in year three.

During the latter half of 2017 and the early part of 2018, Great Lakes sold all of its available 2017-2018 firm winter capacity. This level of contracting is significantly higher than that seen on this pipeline in recent years, and indicates a favorable shift in market dynamics for this asset.

On October 30, 2017, Great Lakes filed a rate settlement with FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018 (2017 Great Lakes Settlement). The 2017 Great Lakes Settlement, which was approved by FERC on February 22, 2018, decreased Great Lakes' maximum transportation rates by 27 percent effective October 1, 2017. Great Lakes expects that, notwithstanding the decrease in rates, the impact from other changes, including: the recent long-term transportation contract with TransCanada as described above, other revenue opportunities on the system and the elimination of the revenue sharing mechanism with its customers, will more than offset the full year impact of the reduction in Great Lakes' rates beginning in 2018. The 2017 Great Lakes Settlement does not contain a moratorium provision and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022.

Northern Border Contracting – Northern Border revenues are substantially supported by firm transportation contracts through the end of 2020. The continued successful renewals of these contracts provide a strong indication of Northern Border's competitive position.

GTN Incremental Contracting – GTN had successful open seasons during late 2017 and the early part of 2018 generally in line with increasing available upstream capacity following the debottlenecking activities on TransCanada's pipelines. As a result, GTN has sold all its available firm capacity beginning mid-2020. GTN continues to provide a key transportation service delivering natural gas out of Western Canada to downstream markets in the Pacific Northwest and California.

Continent to Coast (C2C) Project – In the fourth quarter of 2017, PNGTS filed to increase its FERC-certificated capacity to accommodate the period during which the approximately 82,000 Dth/day of long-term contracts (C2C contracts) overlap with certain of its original contracts which mature in 2019. On November 28, 2017, PNGTS received the approval from FERC to increase its capacity up to approximately 210,000 Dth/day effective December 1, 2017. The C2C contracts were effective December 1, 2017 and they mature in 2032.

Portland XPress Project – PNGTS has executed precedent agreements (PAs) with several local distribution companies (LDCs) in New England and Atlantic Canada (PXP contracts) to re-contract certain system capacity set to expire in 2019 as well as construct incremental compression facilities within PNGTS' existing footprint in Maine (Portland Xpress Project or "PXP"). The PXP contracts, together with the C2C contracts, will provide transportation service of natural gas in the New England area of up to 0.3 Bcf/d by November 1, 2020, effectively utilizing all of PNGTS' expanded capacity through 2032. The in-service dates of PXP will be phased-in over a three-year period beginning November 1, 2018.

PNGTS expects the capital cost of PXP to be approximately $80 million, which PNGTS expects to finance through a new credit facility. Concurrently with PXP, TransCanada will perform upstream capacity expansions of approximately $107 million (TransCanada PXP Expenditures), the majority of which is expected to be incurred following the anticipated receipt dates of required regulatory approvals. In connection with the TransCanada expansions, PNGTS signed a precedent agreement with TransCanada that contemplates the execution of a firm transportation agreement for each of the three phases of PXP, which will be assigned to the LDCs at the completion of each phase. Prior to assignment of the TransCanada transportation agreements to its customers, PNGTS is obligated for the TransCanada PXP Expenditures in the event PXP does not proceed as anticipated.

Northern Border Settlement – Northern Border's 2013 settlement agreement required Northern Border to file for new rates no later than January 1, 2018. On December 4, 2017, Northern Border filed a rate settlement with FERC which precluded the need to file a general rate case by January 1, 2018 (2017 Northern Border Settlement). The 2017 Northern Border Settlement, which was approved by FERC on February 23, 2018, provides for tiered rate reductions effective January 1, 2018, with no change to the underlying rate design. The 2017 Northern Border Settlement does not contain any moratorium and unless superseded by a subsequent rate case or settlement, recourse rates in effect at December 31, 2017, will decrease by 5.0% on January 1, 2018; by an additional 5.5% on April 1, 2018; and by a further 2.0% beginning January 1, 2020 through December 31, 2023, when Northern Border will be required to establish new rates. This equates to an overall rate reduction of 12.5% by January 1, 2020 from the recourse rates in effect at December 31, 2017.

Acquisitions and Financing

Debt Offering – On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 Acquisition.

2017 Acquisition – On June 1, 2017, the Partnership completed the acquisition of a 49.34 percent interest in Iroquois from subsidiaries of TransCanada and an option to acquire a further 0.66 percent interest in Iroquois, together with an additional 11.81 percent interest in PNGTS that results in the Partnership owning a 61.71 percent interest in PNGTS. The total purchase price of the 2017 Acquisition was $765 million plus final purchase price adjustments amounting to approximately $50 million. The purchase price consisted of: (i) $710 million for the Iroquois interest (less $164 million, which reflected the Partnership's 49.34 percent share of Iroquois' outstanding debt at the time of the 2017 Acquisition); (ii) $55 million for the additional 11.81 percent interest in PNGTS (less $5 million, which reflected our 11.81 percent share in PNGTS' outstanding debt at the time of the 2017 Acquisition); (iii) final working capital adjustments for Iroquois and PNGTS amounting to $19 million and $3 million, respectively; and (iv) additional consideration of $28 million for the surplus cash (discussed below) on Iroquois' balance sheet. The Partnership funded the cash portion of the 2017 Acquisition through a combination of proceeds from the May 25, 2017 public debt offering and borrowing under its Senior Credit Facility.

As of the date of the 2017 Acquisition, there was significant cash on Iroquois' balance sheet. Pursuant to the Purchase and Sale Agreement associated with the acquisition of the Iroquois interest, as amended, the Partnership agreed to pay $28 million plus interest to TransCanada on August 1, 2017 for its 49.34 percent share of the cash determined to be surplus to Iroquois' operating needs.

Iroquois' partners adopted a distribution resolution to address the surplus cash on Iroquois' balance sheet post-closing. The Partnership expects to receive the $28 million of unrestricted cash as part of its quarterly distributions from Iroquois over 11 quarters under the terms of the resolution, which began with Iroquois' second quarter 2017 distribution on August 1, 2017. As of February 26, 2018 the Partnership has received approximately $7.8 million of the expected $28 million, of which $5.2 million was received in 2017 and $2.6 million was received on February 1, 2018.

Tuscarora Refinancing – On August 21, 2017, Tuscarora refinanced all of its outstanding debt by amending its existing Unsecured Term Loan Facility and issuing a new $25 million variable rate term loan that will require yearly principal payments beginning September 1, 2018 and will mature on August 21, 2020. Tuscarora's Unsecured Term Loan contains a covenant that requires Tuscarora to maintain a debt service coverage ratio (cash available from operations divided by the sum of interest expense and principal payments) of greater than or equal to 3.00 to 1.00. As of December 31, 2017, the ratio was 11.09 to 1.00.

2013 Term Loan Facility – On September 29, 2017, the Partnership's variable rate $500 million Term loan facility that was due on July 1, 2018 was amended to extend the maturity period through October 2, 2022. As a result of this extension, the Partnership implemented an interest rate hedging strategy during the fourth quarter and hedged the entire $500 million until its October 2, 2022 maturity using forward starting swaps at an average rate of 3.26 percent. At December 31, 2017, the 2013 $500 million Term loan facility was hedged by fixed interest rate swap arrangements at an effective interest rate of 2.31 percent, expiring July 1, 2018.

2015 Term Loan Facility – On September 29, 2017, the Partnership's $170 million Term loan facility that was due on October 1, 2018 was amended to extend the maturity period through October 1, 2020.

2017 US Tax Reform – On December 22, 2017, the President of the United States signed into law H.R. 1 (the "Tax Cuts and Jobs Act" or the "2017 Tax Act"). The 2017 Tax Act resulted in major changes to U.S. tax law, including a decrease in the U.S. corporate federal tax rate from 35 percent to 21 percent effective January 1, 2018. Although we are not a federally taxable entity, we expect the lower tax rates to impact future rate-setting processes on our pipeline systems due to the FERC-regulated nature of our business. The FERC approves our pipelines' rates on a cost-of-service basis which includes a recovery of our ultimate taxable owners' income tax expense as a component of the rates charged to customers. Over time, we expect these changes will impact our future performance through changes in the cash flows generated by our subsidiaries and distributions from our equity investments.

Please refer also to Note 4 the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules" and Part II- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Critical Accounting Estimates for more information.)

Business Strategies

- Our strategy is to invest in long-life critical energy infrastructure that provides reliable transportation 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 a 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, precluding the need for FERC to conduct a rate case, which may include mutually beneficial performance incentives. A settlement is ultimately subject to FERC approval.

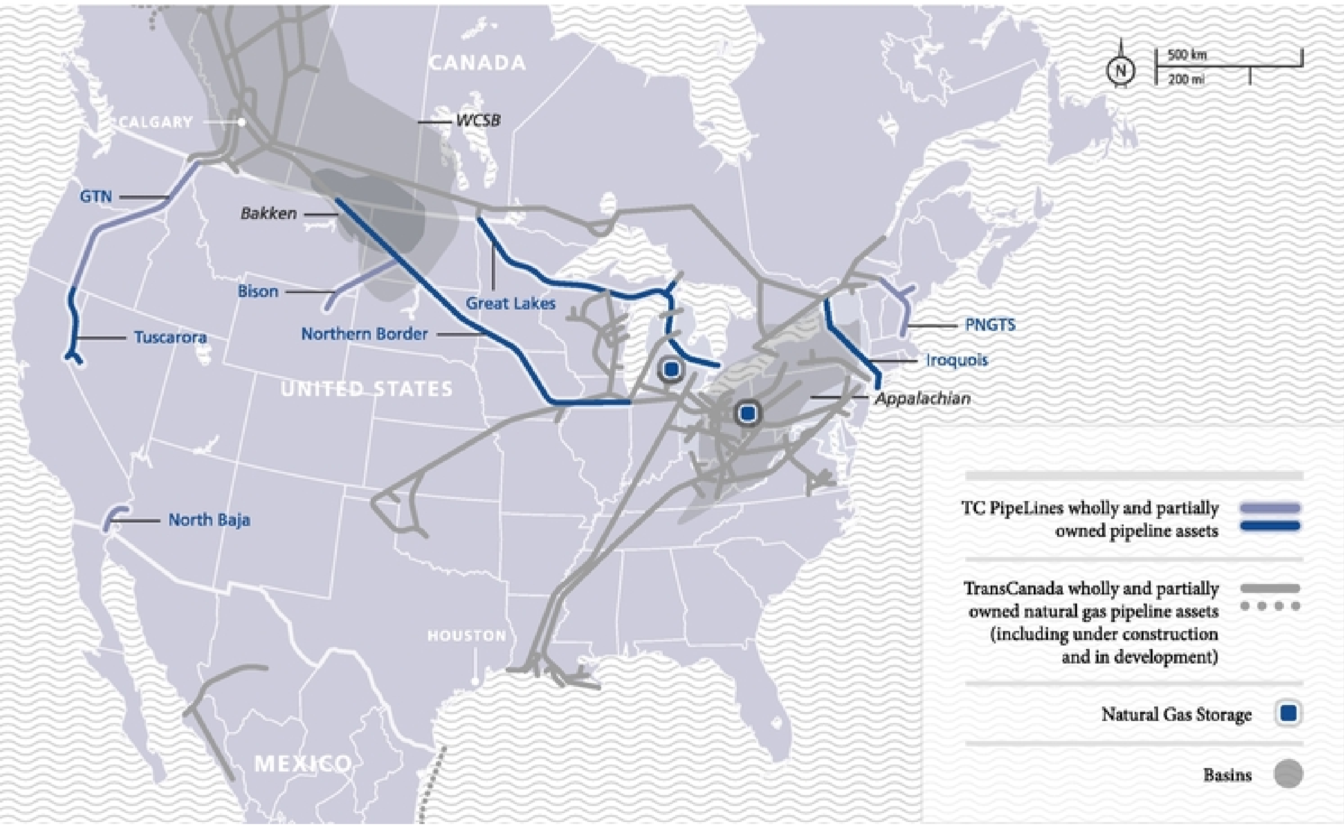
Contracting

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, 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 natural gas transportation and consumption, in the region in which the pipeline is situated.

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, relative cost of natural gas supply and changing market demand.

The map below shows the location of certain 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. The ongoing 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 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 ownership interests in eight natural gas interstate pipeline systems that are collectively designed to transport approximately 10.4 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, except Iroquois and the PNGTS joint facilities, are operated by subsidiaries of TransCanada. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The PNGTS Joint Facilities (see below) are operated by MNOC, a subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.

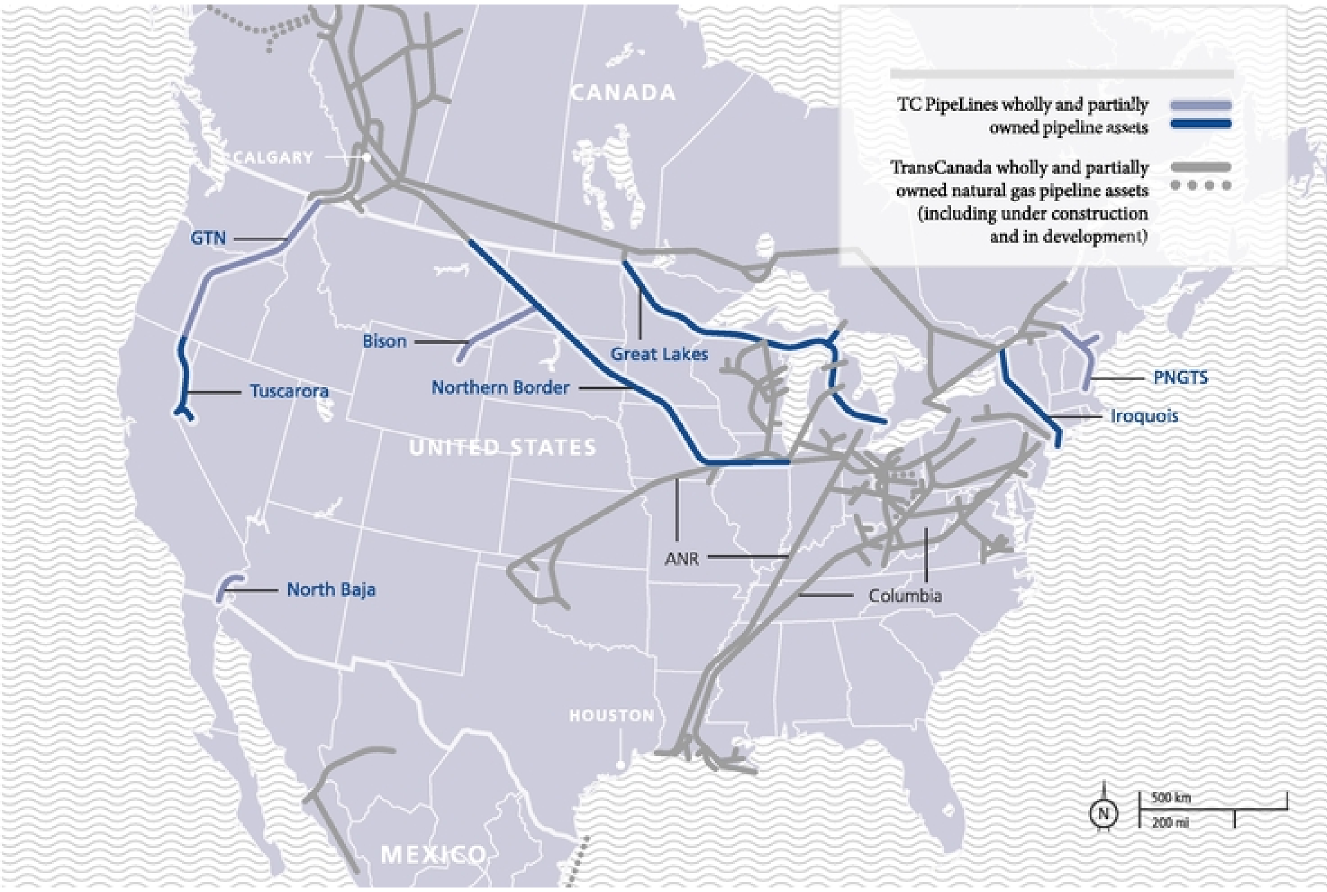
Our pipeline systems include:

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
Bison Pipeline LLC (Bison)	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can transport natural gas from the Powder River Basin to Midwest markets.	100 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
Northern Border Pipeline Company (Northern Border)	1,412 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 Bakken, 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
Portland Natural Gas Transmission System (PNGTS)	295 miles	Connects with the TQM at the Canadian border to deliver natural gas to customers in the U.S. northeast. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS. The 295-mile pipeline includes 107 miles of jointly owned pipeline facilities (the Joint Facilities) with Maritimes and Northeast Pipeline LLC (MNE). The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32% of the undivided ownership interest based on contractually agreed upon percentages.	61.71 percent[(a)]
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
Iroquois Gas Transmission System, L.P (Iroquois)	416 miles	Extends from the TransCanada Mainline system near Waddington, New York to deliver natural gas to customers in the U.S. northeast. The remaining 50.66 percent is owned by TransCanada (0.66 percent), Dominion Midstream (25.93 percent) and Dominion Resources (24.07 percent).	49.34 percent[(b)]

(a) On June 1, 2017, the Partnership acquired an additional 11.81 percent interest from TransCanada resulting in 61.71 percent ownership in PNGTS. (Refer to Note 7 of the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules")

(b) Effective June 1, 2017 (Refer to Note 7 of the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules")

The map below shows the location of our pipeline systems.



Customers, Contracting and Demand

Our customers are generally large utilities, LDCs, major natural gas marketers, 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, LDCs, 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."

One of our customers, Anadarko Energy Services Company accounted for a significant portion of our revenue and comprised 11 percent of the Partnership's revenues in 2017.

GTN – GTN's revenues are substantially supported by long-term contracts through the end of 2023 with its remaining contracts extending between 2024 and 2045. These contracts, which have historically been renewed on a long-term basis upon expiration, are primarily held by LDCs that 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 natural gas supplies and deliveries to Northern California.

Currently, GTN is benefitting from an increase in the volumes of natural gas it transports as debottlenecking activities occur on upstream pipeline systems which deliver natural gas to GTN. These upstream activities are continuing and as a result, we are in the process of signing over 700,000 Dth/day in long-term contracts of which 348,000 Dth/day will result in additional volumes flowing onto GTN as early as mid-2018 with the remainder from 2019 to 2020. The majority of these contracts have terms of at least 15 years.

Northern Border – Northern Border is a highly competitive pipeline system and is fully contracted with its revenues substantially supported by firm transportation contracts through the end of 2020. Northern Border's contracts include renewal rights and expiring contracts have typically been renewed for terms of five years. In addition, Northern Border sells seasonal transportation services which have 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 both short-haul and long-haul transportation services. The majority of its 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 the upper Midwest of the U.S. During the latter half of 2017 and the early part of 2018, Great Lakes sold all of its available 2017-2018 firm winter capacity. This level of contracting is significantly higher than that seen on this pipeline in recent years, indicative of a favorable shift in market dynamics for Great Lakes.

During 2017, Great Lakes benefited from TransCanada's new long-term fixed price service on its Canadian Mainline. Concurrent with the launch of this new service, Great Lakes entered into a long-term transportation agreement with TransCanada's Canadian Mainline for 0.711 billion of cubic feet that commenced on November 1, 2017 for a ten-year period and contains volume reduction options up to full contract quantity beginning in year three. This provides long-term capacity to TransCanada's shippers for the transportation of WCSB natural gas to markets in Eastern Canada and the U.S.

PNGTS – PNGTS' revenues are primarily generated from transportation agreements with LDCs throughout New England. The majority of PNGTS' current revenue stream is supported by long-term contracts. Long-term contract commitments of approximately 82,000 Dth/day from the C2C open season began December 1, 2017, necessitating an increase in PNGTS' certificated capacity up to approximately 210,000 Dth/day. The C2C contracts mature in 2032 and replaced some expiring short-term and long-term contracts.

In addition to the C2C contracts, in 2017, PNGTS executed 20-year PAs with several LDCs in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019 as well as expand the PNGTS system to bring its certificated capacity up to approximately 0.3 Bcf/day by November 1, 2020, effectively utilizing all of PNGTS' expanded capacity through 2032.

PXP will proceed concurrently with upstream capacity expansions on the Trans Quebec & Maritimes Pipeline (TQM) and TransCanada's Canadian Mainline systems. The in-service dates of PXP are being phased-in over a three-year period beginning November 1, 2018. PXP, together with the C2C expansion brings additional, natural gas supply options to markets in New England and Atlantic Canada in response to the growing need for natural gas transportation capacity in the region.

Iroquois – Iroquois transports natural gas under long-term contracts that expire between 2018 and 2026 and extends from TransCanada's Canadian Mainline system at the U.S. border near Waddington, New York to markets in the U.S. northeast, including New York City, Long Island and Connecticut. Iroquois provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, directly or indirectly, through interconnecting pipelines and exchanges throughout the northeastern U.S. Iroquois also earns discretionary transportation service revenues which can have a significant earnings impact. Discretionary transportation service revenues include short-term firm transportation service contracts with less than one-year terms as well as standard interruptible transportation service contracts. In 2017, Iroquois earned approximately 11 percent of its revenues from discretionary services.

Bison – Natural gas is currently not flowing in response to the recent relative cost advantage of WCSB- and Bakken -sourced gas versus Rockies production. Bison has not experienced a decrease in its revenue as it is fully contracted on a ship-or-pay basis through January of 2021.

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

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.

GTN and Northern Border, through their respective connections with TransCanada's Foothill systems, and Great Lakes and Iroquois, through their respective connections with TransCanada's Canadian Mainline, compete with each other for WCSB natural gas supply as well as with other pipelines, including 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 MNE from Westbrook, Maine to a connection with the Tennessee Gas Pipeline System near Boston, Massachusetts. PNGTS competes with LNG supplies and gas flows from Canada and with LNG delivered into Boston. Tennessee Gas Pipeline and Algonquin Gas Transmission also compete with PNGTS for gas deliveries into New England markets.

As noted above, Iroquois, through its connection with TransCanada's Canadian Mainline System, competes for WCSB natural gas supply with other pipelines. Iroquois connects at five locations with three interstate pipelines (Tennessee Gas, CNG Gas Transmission and Algonquin Gas Transmission) and TransCanada's Canadian Mainline System near Waddington, New York and provides a link between WCSB natural gas deliveries to markets in the states of Connecticut, Massachusetts, New Hampshire, New Jersey, New York, and Rhode Island.

Additionally, our pipeline assets face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our pipeline systems' investment hurdles or projects that proceed with lower overall financial returns.

Relationship with TransCanada

TransCanada is the indirect parent of our General Partner and at December 31, 2017, owns, through its subsidiaries, approximately 24.2 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's business is primarily focused on natural gas and oil transmission and power generation services. TransCanada consists of investments in 57,100 miles natural gas pipelines, 3,000 miles of wholly-owned oil pipelines and 653 billion cubic feet of natural gas storage capacity. TransCanada also owns or has interests in over 6,100 megawatts of power generation.

TransCanada operates most of 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 Partnership as a core element of its strategy and considers the dropdown of assets into the Partnership as an effective financing option as it executes its capital growth program, subject to actual funding needs and market conditions. There can be no assurance 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 – GTN operates under rates established pursuant to a settlement approved by FERC in June 2015. Effective July 1, 2015, the rates were reduced by three percent. In January 2016, GTN's rates decreased by 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.

Great Lakes – On October 30, 2017, Great Lakes filed a rate settlement with FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement, which was approved by FERC on February 22, 2018, decreased Great Lakes' maximum transportation rates by 27 percent effective October 1, 2017. The 2017 Great Lakes Settlement does not contain any moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022.

Northern Border – Northern Border's 2013 settlement agreement required Northern Border to file for new rates no later than January 1, 2018. On December 4, 2017, Northern Border filed a rate settlement with FERC precluding the need to file a general rate case by January 1, 2018 (2017 Northern Border Settlement). The 2017 Northern Border Settlement, which was approved by FERC on February 23, 2018, provides for tiered rate reductions beginning January 1, 2018, with no change to the underlying rate design. The 2017 Northern Border Settlement does not contain a moratorium provision and unless superseded by a subsequent rate case or settlement, recourse rates in effect at December 31, 2017, will decrease by 5.0% on January 1, 2018; by an additional 5.5% on April 1, 2018; and by an additional 2.0% beginning January 1, 2020 through December 31, 2023, when Northern Border will be required to establish new rates. This equates to an overall rate reduction of 12.5% by January 1, 2020 from the recourse rates in effect at December 31, 2017.

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.

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, 2017, North Baja notified FERC that current market conditions do not support the replacement of the compression that was temporarily abandoned in 2013 and requested authorization to permanently abandon two compressor units and a nominal volume of unsubscribed firm capacity. FERC approved the permanent abandonment request on February 16, 2017. The requested abandonments will not have any impact on existing firm transportation service.

Tuscarora – Tuscarora operates under rates established pursuant to a settlement approved by FERC in September 2016. Under the settlement, Tuscarora's system-wide unit rate initially decreased by 17 percent, effective August 1, 2016. Unless superseded by a subsequent rate case or settlement, this rate will remain in effect until July 31, 2019, after which time the unit rate will decrease by an additional seven percent from August 1, 2019 through July 31, 2022. The settlement does not contain a rate moratorium provision and requires Tuscarora to file to establish new rates no later than August 1, 2022.

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.

Iroquois – Iroquois operates under rates established pursuant to a settlement approved by FERC in October 2016. Under the settlement, Iroquois rates decreased ratably during the phase-in period from September 2016 through 2018 with an overall reduction of approximately 20 percent beginning September 2018. The settlement also contains a rate moratorium until September 1, 2020. Unless superseded by a subsequent rate case or settlement, Iroquois will be required to establish new rates no later than September 1, 2022.

The 2017 Tax Act and FERC's Income Tax Recovery Inquiry

On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act. This legislation provides for major changes to U.S. tax law with the most significant change being the reduction of the corporate federal income tax rate from 35 percent to 21 percent. As mentioned in the section Narrative Description of Business – General and Note 2 of the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules", we are a non-taxable master limited partnership, and income taxes owed as a result of our earnings are the responsibility of our partners. However, all of our pipeline systems are regulated by the FERC, which approves the systems' rates on a cost-of-service basis and includes a recovery of our ultimate taxable owners' income tax expense as a nominal component of the maximum allowable rates that may be charged to customers. Ultimate rates charged to customers are typically reached through negotiation without ascribing specific elements of costs of service such as income taxes.

In December 2016, FERC issued a Notice of Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs (Docket No. PL17-1-000) requesting Initial Comments regarding how to address any double recovery resulting from FERC's current income tax allowance and rate of return policies that are in effect since 2005.

Docket No. PL17-1-000 is a direct response to *United Airlines, Inc., et al. v. FERC*, a decision issued by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016 in which the D.C. Circuit directed FERC to explain how a pass-through entity such as a master limited partnership receiving a tax allowance and a return on equity derived from the discounted cash flow (DCF) methodology did not result in double recovery of taxes.

Various comments have been received by FERC and most recently, comments on how the 2017 Tax Act will affect the income tax recovery allowed on regulated pipelines.

There is not likely to be a definitive resolution of these issues for some time. The ultimate outcome of Docket No. PL17-1-000 is not certain and could result in changes going forward to FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of any of our interstate natural gas pipelines could be affected to the extent the pipeline proposes new rates or changes to its existing rates or if its rates are subject to complaint or challenged by FERC which would ultimately impact our future operating performance.

Review of FERC Natural Gas Pipelines Policy

The current FERC Chairman announced in December 2017 that FERC will review its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline entity operating in the United States.

Environmental

Our pipelines are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including air emissions, biodiversity, wastewater discharges, waste management and water quality. 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 limiting or prohibiting operations in affected areas.

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

- *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.

- *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.

- *Solid Wastes and Hazardous Substance and Wastes Statutes* – The operations of our pipeline systems are subject to federal and analogous 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.

- *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 and the U.S. Army Corps of Engineers (Corps) released a final rule in May 2015 that attempted to clarify federal jurisdiction under the CWA over waters of the U.S. This interpretation by the EPA may constitute an expansion of federal jurisdiction over waters of the U.S. Implementation of the rule has been stayed nationwide, and in January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction over the challenge to the rule rests with the federal district or appellate courts. In February 2017, President Trump issued an executive order directing the EPA and the Corps to review and, consistent with applicable law, initiate a rulemaking to rescind or revise the rule. The EPA and the Corps proposed in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the CWA's jurisdiction, and published a proposed rule in November 2017 that would stay implementation of the June 2015 rule for two years. The Supreme Court ruled in January 2018 that jurisdiction to decide challenges to the rule rests with federal district courts. Consequently, while implementation of the 2015 rule remains stayed, the previously-filed district court cases challenging the scope of rule will be allowed to proceed. As a result of these developments, future implementation of the June 2015 rule is uncertain at this time, but to the extent that this rule or any subsequent replacement 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 and appeal by environmental groups, who have frequently used the NEPA process to challenge pipeline construction projects over the past several years, and therefore, have the potential to delay current and future natural gas transportation activities.

- *National Historic Preservation Act (NHPA)* – The NHPA restricts activities that may affect cultural and historic resources through the implementation of procedural protections that require identification and protection of cultural and historic resources of national, state, tribal and local significance. The presence of cultural and historic resources, including the designation of previously unidentified resources or sites have the potential to delay current and future natural gas transportation activities.

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.

Climate Change and Greenhouse Gas Emissions

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, and state levels of government to regulate emissions of greenhouse gases (GHGs). At the federal level, no comprehensive climate change legislation has been implemented to date, but 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 and blowdowns of natural gas transmission pipelines between compressor stations in the U.S. on an annual basis.

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.

Recent federal rulemakings have focused on the emission of methane, which is considered by the EPA as a GHG. In June 2016, the EPA published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued New Source Performance Standards published by the EPA in 2012, known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for modified pneumatic controllers and pumps as well as compressors and imposing leak detection and repair requirements for natural gas compressor and booster stations that are modified through an increase in horsepower. However, over the past year the EPA has taken several steps to delay implementation of the methane rules. In June 2017, EPA proposed to stay the Subpart OOOOa standards for a period of two years and a separate 90-day stay of the standards to provide time for the 2-year stay to take effect while EPA reconsiders implementation of the Subpart OOOOa standards in their entirety. The EPA has not yet finalized the June 2017 proposed rulemaking and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 rules is uncertain at this time.

In November 2017, the EPA published two Notices of Data Availability (NODAs) for Subpart OOOOa in the Federal Register and initiated a 30-day public comment period. One NODA relates to the June 2017 two year stay to reconsider the rule and the other NODA relates to the EPA's 90-day stay to cover the 60-day time-period between final publication of the 2-year stay in the Federal Register and the time the proposed 2-year stay takes effect. We do not believe that compliance with the Subpart OOOOa regulations will have a material adverse effect on our operations even if the stay is ultimately vacated in court and the rule is fully implemented. However, given the uncertainty of policy and rulemaking regarding this rule the future effects on our pipelines cannot be predicted.

On an international level, in June 2017, the U.S. Federal government announced its intent to withdraw from the 2015 international climate change agreement known as the Paris Agreement and the U.S. State Department formally notified the United Nations in August 2017 of the United States' intent to withdraw from the agreement. The Paris Agreement requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. Following the U.S. Federal government announcement to withdraw from the Paris Agreement, a number of U.S. State governments announced their commitment to the Paris Agreement. 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. However, 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 many 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. Significant changes in temperature and other weather events can have many effects on our business, ranging from an impact on demand, availability and commodity prices, to efficiency and output capability.

U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA)

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), the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the 2011 Pipeline Safety Act) and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the 2016 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 our operator, TransCanada, Iroquois and MNOC 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. Effective April 27, 2017, to account for inflation, those maximum civil penalties were increased to $209,002 per violation per day, with a maximum of $2,090,022 for a series of violations.

The ongoing laws 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.

Additional rule makings regarding pipeline safety are likely. In June 2016, the 2016 Pipeline Safety Act was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Act. As a result, in May 2016, PHMSA proposed new rules for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting, and integrity management requirements on operators. However, to date, no further action has been taken with respect to this proposed rulemaking. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as further amended by the 2016 Pipeline Safety Act, as well as any implementation of PHMSA rules or any issuance or reinterpretation of guidance by PHMSA or any other state agencies with respect thereto, could require us to install new or modified safety controls, pursue additional capital projects, conduct maintenance programs on an accelerated basis, or result in a temporary or permanent reduction in maximum allowable operating pressure, which would reduce available capacity on our pipelines, any or all of which could result in our incurring increased operating costs that could be significant, and have a material adverse effect on our results of operations or financial condition.

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 or third party property damage claims, 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.

Occupational Safety and Health Administration (OSHA)

Our pipelines are also subject to the requirements of the OSHA and other federal and state agencies that address employee health and safety. In general, we believe that TransCanada's, Iroquois' and MNOC's programs and costs incurred are addressing the OSHA requirements and protecting the health and safety of employees. Based on new regulatory developments, pipeline operators may increase expenditures in the future to comply with higher industry and regulatory safety standards. However, such increases in costs of compliance, and the extent to which they might be recoverable through our pipeline's rates, cannot be estimated at this time.

Cyber security

We rely on our information technology to process, transmit and store electronic information, including information pipeline operators use to safely operate our assets. We, our operators and other energy infrastructure companies in jurisdictions where we do business continue to face cyber security risks. Cyber security events could be directed against companies in the energy infrastructure industry.

A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.

TransCanada, the indirect parent of our General Partner and the operator of most of our assets, has a cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, preventions, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/ processes and a cyber security awareness program for employees. TransCanada also has insurance which covers reasonably foreseeable losses due to damage to our facilities, and losses incurred by others, as a result of a cyber security event. These polices do not, however, cover losses that may result from a cyber security event that prevents TransCanada from operating our facilities but does not result in any physical damage. There is no certainty that costs incurred related to securing against these threats will be recovered through rates.

EMPLOYEES

We do not have any employees. We are managed and operated by our General Partner. Subsidiaries of TransCanada operate most of our pipelines systems pursuant to operating agreements, with the exception of the Iroquois pipeline system and the PNGTS joint facilities. The Iroquois pipeline system is operated by a wholly owned subsidiary of Iroquois. The PNGTS joint facilities are operated by MNOC, a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.

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 earn net income.

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 and changes in demand for our transportation services;
- 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 or high 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, 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. In addition, many U.S. environmental laws provide for citizen suits, and environmental groups frequently use these provisions to challenge environmental reviews and permits issued in connection with pipeline infrastructure projects, resulting in costly delays. 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 to sell its assets to the Partnership, subject to TransCanada's 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.

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, 2017, $435 million of our total $2,415 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, 2017, the $500 million 2013 Term Loan Facility was hedged by fixed interest rate swap and forward starting swap arrangements.

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 may 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.

The prolonged low oil and natural gas prices 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 an equity investment, a long-lived asset 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. This could have a negative impact on the common unit price.

As an example, in 2015, we recognized an impairment charge on our equity investment in Great Lakes amounting to $199 million and in 2016, our analysis on Tuscarora's goodwill balance indicated that the excess of its fair value over the carrying value, including goodwill was less than 10 percent.

There is a risk of future impairments related to our equity investments, goodwill or long-lived assets. If assumptions relied upon change, there can be no assurance no future impairment charge will be made with respect to our equity investments, goodwill and long-lived assets.

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 our Equity Investments in Northern Border, Great Lakes and Iroquois, which limits our ability to control these assets.

We do not own a controlling interest in our Equity Investments 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 us. These management committees generally require 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.

Natural gas on Bison is currently not flowing as a result of a change in demand for its services. There can be no assurance that we will be able to replace Bison's existing contracts and maintain its current revenues which could significantly reduce our earnings and cash flows.

Natural gas on Bison is currently not flowing in response to the relative cost advantage of WCSB – and Bakken-sourced gas versus Rockies production. Bison has not experienced a decrease in its revenue as it is fully contracted on a ship-or-pay basis through January of 2021. However, we may not be able to renew or contract for this capacity if this market condition continues to persist.

While we are currently working on other strategic alternatives to maximize the value of this asset which include discussions with producers in the area to determine the best use for Bison, including if the asset can be reversed, redirected or repurposed, there is a risk that options available at this time will not bring back the same level of revenue Bison currently generates. More importantly, Bison's revenues comprise approximately 19 percent of our consolidated revenues and if we are unsuccessful in securing contracts for Bison in the future or the options available to us do not materialize, there could be a significant reduction in our earnings and cash flows and ultimately, an impairment on Bison's long lived assets.

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.

For example, in December 2016, FERC issued a Notice of Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs (Docket No. PL17-1-000) requesting Initial Comments regarding how to address any double recovery resulting from FERC's current income tax allowance and rate of return policies that are in effect since 2005.

Various comments have been received by FERC and most recently, comments on how the 2017 Tax Act will affect the income tax recovery allowed on regulated pipelines. While the outcome of the inquiry is still pending, we believe that there is not likely to be a definitive resolution of these issues for some time. However, the outcome could result in changes going forward to FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity that could have an impact on the rates of any of our interstate natural gas pipelines.

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, environmental regulation, 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. During 2016, PHMSA posted warnings to all pipeline owners and operators of the importance of safeguarding and securing their pipeline facilities and monitoring their supervisory control and data acquisition (SCADA) systems for abnormal operations and/or indications of unauthorized access or interference with safe pipeline operations based on recent incidents involving environmental activists.

These potential security events might include our pipeline systems or operating systems and may result in damage to our pipeline facilities and 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 physical assets to transport the energy we deliver and our information technology to process, transmit and store electronic information, including information TransCanada uses to safely operate our pipeline systems. Security breaches could expose our business to a risk of loss, misuse or interruption of critical physical assets or information and functions that affect the pipeline operations. Such losses could result in operational impacts, damage to our assets, public or personnel 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 and commitments may limit their ability to borrow additional funds, make distributions to us or capitalize on business opportunities.

Our pipeline systems' respective debt levels and commitments 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.

In the event the PXP project does not proceed, PNGTS may be responsible for the reimbursement of TransCanada's upstream capital expenditures on the related Canadian system expansions, which could have a negative impact on PNGTS' ability to make cash distributions to its partners.

In connection with PXP, PNGTS has entered into an arrangement with TransCanada regarding the construction of certain facilities on its system that will be required to fulfill future contracts on the PNGTS' system. In the event the TransCanada expansions terminate prior to the in-service date of the final phase of PXP, PNGTS could be required to reimburse TransCanada for up to the amount of TransCanada PXP Expenditures incurred to date of termination, the majority of which is expected to be incurred following the anticipated receipt dates of required regulatory approvals, prior to the end of phase II of the project. As of December 31, 2017, the total incurred was approximately $3 million. If PNGTS were required to reimburse TransCanada for TransCanada PXP Expenditures, it would reduce cash available for distributions to us and therefore reduce our cash available for distributions to unitholders. A project construction plan is in place to minimize expenditures until certain regulatory approvals are received.

See also Part I, Item 1. "Business-Recent Business Developments" for further information on the PXP Project.

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, ruptures, earthquakes, adverse weather conditions and other natural disasters; terrorist activity, civil disobedience 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. We could also 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 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 FERC. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for violations of up to approximately $1.2 million 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. New legislation or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital costs, operational delays and costs of operations. For example, PHMSA has adopted or proposed pipeline safety regulations in 2011 and, more recently, in 2016 in response to legislation passed by the U.S. Congress that, among other things, increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines, and empowered PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of regulated pipeline facilities without prior notice or an opportunity for a hearing.

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 requirements.

Each of our pipeline systems is subject to federal, state and local environmental laws, regulations and enforcement policies. Potential liabilities may arise related to protection of the environment and natural resources. New environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs. As an example, under the Clean Air Act the 2015 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. States have submitted their initial non-attainment designations to the EPA and the agency expects to issue final non-attainment designation in 2018. Depending upon State Implementation Plans and the outcome of any legal challenges to such designations, additional permitting delays and expenditures for pollution control equipment could occur. This example illustrates the uncertainty to which proposed laws, regulations or reforms, if any, will be adopted and what impact they might ultimately have on our operations or financial results.

Under certain environmental laws and regulations, we may be exposed to substantial liabilities for pre-existing contamination that arise in connection with our past or current operations. For example, during routine maintenance activities, we may discover historical hydrocarbon or polychlorinated biphenyl contamination, which may require notification to the appropriate governmental authorities and corrective action to address.

There also exist legal initiatives directly affecting our customers that could indirectly affect our operations by reducing the need for our services. Such developments could cause our customers to incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which subsequently could reduce demand for our transportation services.

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, 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. Recent federal rulemakings have focused on the emission of methane, which is considered by the EPA as a GHG. For example, in June 2016, the EPA published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued New Source Performance Standards published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for modified pneumatic controllers and pumps as well as compressors and imposing leak detection and repair requirements for natural gas compressor and booster stations that are modified through an increase in horsepower. However, over the past year the EPA has taken several steps to delay implementation of these methane standards, and the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of the Subpart OOOOa rules in their entirety. The EPA has not yet published a final rule and the June 2016 rule remains in effect, but future implementation of the 2016 Subpart OOOOa standards is uncertain at this time. 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 could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, demand for our services, financial condition, results of operations and cash flows.

The Cap and Invest Legislation (HB 4001 and SB 1507) that is scheduled to be proposed during the 2018 Oregon legislative session could result in higher cost of operating the GTN pipeline system

The Oregon Legislature is considering several GHG proposals that would regulate GHG emissions through a "cap-and-invest" program. The Cap and Invest Legislation (HB 4001 and SB 1507) is scheduled to be proposed during the 2018 Oregon legislative session that, in its current form, would provide GHG allowances to be allotted and sold by various entities. The information provided has not allowed us to reasonably anticipate or estimate the outcome of this proposed legislation at this time. Additionally, the Oregon Department of Environmental Quality are considering proposed rules to amend existing air quality rules. Comments to the proposed "Cleaner Air Oregon" rulemaking was scheduled for early 2018. At this time, we cannot reasonably estimate the impact of the proposed amended rules in its final form; however, it is expected that these rules will become finalized in 2018.

Recent pipeline safety legislation and proposed regulations could result in more stringent requirements on our facilities and systems that could trigger significant capital and operating costs.

The 2016 Pipeline Safety Act requires that PHMSA publish periodic updates on the status of those mandates outstanding from the 2011 Pipeline Safety Act, of which numerous initiatives remain to be completed. The mandates yet to be acted upon include requiring certain shut-off valves on transmission lines, mapping all high consequence areas, and shortening the deadline for accident and incident notifications.

In March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for natural gas pipelines. To date, no further action with respect to this proposed rulemaking has been taken. We continue to monitor proposed rulemaking developments and evaluate its potential impact, if any, of 2016 Pipeline Safety Act, in light of the many PHMSA initiatives and mandates. At this time, we cannot predict the ultimate impact of this legislation, and subsequent revisions to regulations on our operations; however, the adoption of any new legislation or regulations regarding increased pipeline safety could cause us to incur increased capital and operating costs, which costs could be significant.

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.

We do not own the majority of the land on which our pipeline systems are located, which could result in higher costs and disruptions to our operations, particularly with respect to easements and rights-of-way across Indian tribal lands.

We do not own the majority of the land on which our pipeline systems are located. We obtain easements, rights-of-way and other rights to construct and operate our pipeline systems from individual landowners, Native American tribes, governmental authorities and other third parties. Some of these rights expire after a specified period of time. As a result, we are subject to the possibility of more onerous terms and increased costs to renew expiring easements, rights-of-way and other land use rights. While we generally are able to obtain these rights through agreement with land owners or legal process, if necessary, rights-of-way across Indian tribal land require approval of the applicable tribal governing authority and the Bureau of Indian Affairs (the "BIA"). If efforts to retain existing land use rights on tribal land at a reasonable cost are unsuccessful, our pipeline systems could also be subject to a disruption of operations and increased costs to re-route the applicable portion of our pipeline system located on tribal land. Increased costs associated with renewing or obtaining new easements or rights-of-way and any disruption of operations could negatively impact the results of operations and cash available for distribution of our pipeline systems.

Our Great Lakes pipeline system has rights-of-way expiring during the second quarter of 2018 on approximately 7.6 miles of pipeline across tribal land located within the Fond du Lac Reservation and Leech Lake Reservation in Minnesota and the Bad River Reservation in Wisconsin. We are negotiating to renew the rights-of-way with the tribal authorities. If we are unable to reach agreement regarding these rights-of way prior to expiration of the existing easements, we expect to continue operating the Great Lakes pipeline while continuing good faith negotiations with the tribal authorities to obtain the necessary rights. If these discussions ultimately are unsuccessful, we could be required to remove pipe from the tribal lands and re-route the applicable portion of the Great Lakes pipeline system. While the outcome of these negotiations or the ability to reach agreement prior to expiration of the existing rights is uncertain, the impact of a disruption of operations or significantly increased costs to renew the rights-of-way could have a material adverse effect on our financial condition, results of operations and cash flows.

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 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 24.2 percent of our outstanding common units at December 31, 2017, 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, 2017, the General Partner and its affiliates own approximately 24.2 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 the year ended December 31, 2017 we paid fees and reimbursements to our General Partner in the amount of $4 million (2016 and 2015 – $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.

Changes in TransCanada's costs or their cost allocation practices could have an effect on our results of operations, financial position and cash flows.

Under the Partnership Agreement, the Partnership's pipeline systems operated by TransCanada are allocated certain costs of operations at TransCanada's sole discretion. Accordingly, revisions in the allocation process or changes to corporate structure may impact the Partnership's operating results. TransCanada reviews any changes and their prospective impact for reasonableness, however there can be no assurance that allocated operating costs will remain consistent from period to period.

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, 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.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state, or local income tax purposes, then specified provisions of the Partnership Agreement relating to distributions will be subject to change. These changes would include a decrease in distributions to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes 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. From time to time, members of the U.S. Congress have proposed and considered substantive changes to the existing U.S. federal tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception for all publicly traded partnerships upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, on January 24, 2017, final regulations (the Final Regulations) regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended (the Code) were published in the Federal Register. We do not believe the Final Regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

However, 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.

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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Under our limited Partnership Agreement, our general partner is permitted to make elections under the new rules to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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

Because unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash distributed, unitholders may be required to pay 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.

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.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the 2017 Tax Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. Although the interest limitation does not apply to certain regulated pipeline businesses, application of the interest limitation to tiered businesses like ours that hold interests in regulated businesses is not clear. Pending further guidance specific to this issue, we are not able to determine the impact the limitation could have on our unitholders' ability to deduct our interest expense, but it is possible that our unitholders' interest expense deduction will be limited.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The 2017 Tax Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a 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 generally 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 generally 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 (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Final Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. 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 consult a tax advisor to determine whether it is advisable 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.

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

We believe that we hold satisfactory rights, title and interests in the properties owned or used by our 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 individuals, governmental authorities, Native American tribes (as further discussed below) and other third parties pursuant to leases, easements, rights-of-way, permits and licenses, the majority of which are perpetual. Certain land use rights, in particular rights-of-way on tribal land, are subject to periodic renewal. 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 our Northern Border 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 our Great Lakes pipeline system is located within the boundaries of three Indian reservations: the Leech Lake Reservation and the Fond du Lac Reservation in Minnesota, and the Bad River Reservation in Wisconsin. Great Lakes has right-of-way access across allotted and tribal lands located within each reservation's boundaries that expire in the second quarter of 2018. Great Lakes is in discussions with tribal authorities for the renewal of approximately 7.6 miles of rights-of-way access prior to their expiration. The Great Lakes pipeline also crosses approximately 1,000 feet in two tracts under perpetual easement located within the Chippewa Indian Reservation in Lower Michigan.

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 proceeding:

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 (Essar Minnesota) and certain Foreign 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 Eighth Circuit (Eighth 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 Eighth Circuit heard the appeal on October 20, 2016. A decision on the appeal was received in December 2016 and the Eighth Circuit vacated Great Lakes' judgment against Essar finding that there was no federal jurisdiction. Great Lakes filed a Request for Rehearing with the Eighth Circuit and it was denied in January 2017. Before the Circuit Court issued its decision, Essar Minnesota filed for bankruptcy in July 2016. The Foreign Essar Affiliates have not filed for bankruptcy. Following the Circuit Court's decision, the performance bond was released into the bankruptcy court proceedings. Great Lakes filed a claim against Essar Minnesota in the bankruptcy court and its case against the Foreign Essar Affiliates in Minnesota state court remains pending. In April 2017, after Great Lakes agreement with creditors on an allowed claim, the bankruptcy court approved Great Lakes' claim in the amount of $31.5 million. On May 20, 2017, the federal district court awarded Essar Minnesota approximately $1.2 million for costs, including recovery of the performance bond premium, to be paid by Great Lakes. Great Lakes filed a motion with the bankruptcy court to offset the $1.2 million award of costs against its claim against Essar Minnesota in the bankruptcy proceeding but was unsuccessful. As a result, Great Lakes accrued the $1.2 million in its books. Great Lakes is unable to estimate the timing or the extent to which its claim will be recoverable in the bankruptcy proceedings.

Item 4. Mine Safety Disclosures

None.

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

As of February 22, 2018, there were approximately 35 holders of record of our common units. Our common units trade on the NYSE under the symbol "TCP".

As of February 22, 2018, the Partnership had 71,306,396 common units outstanding, of which 54,221,565 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. 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	
2017			
First Quarter	**$65.03**	**$57.02**	**$0.94**
Second Quarter	**$61.74**	**$51.06**	**$1.00**
Third Quarter	**$59.30**	**$49.83**	**$1.00**
Fourth Quarter	**$55.59**	**$48.55**	**$1.00**
2016			
First Quarter	$55.00	$34.25	$0.89
Second Quarter	$60.48	$46.50	$0.94
Third Quarter	$58.66	$50.24	$0.94
Fourth Quarter	$59.12	$47.12	$0.94

On February 13, 2018, we paid a cash distribution of $76 million to common unitholders and the General Partner, representing a cash distribution of $1.00 per common unit for the quarter ended December 31, 2017. The distribution was allocated in the following manner: $71 million to the common unitholders as of the close of business on February 2, 2018 (including approximately $17 million to TransCanada as holder of 17,084,831 common units), and $5 million to the General Partner, which included $2 million for its effective two percent general partner interest and $3 million for its IDRs. In 2017, the Partnership made cash distributions to common unitholders and the General Partner that amounted to $284 million compared to $250 million in 2016.

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.

Incentive distributions are paid to our General Partner if quarterly cash distributions on the common units exceed levels specified in the Partnership Agreement. See Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cash Distribution Policy of the Partnership" for further information regarding IDRs.

In 2017, we paid incentive distributions to our General Partner of approximately $10 million (2016 – $6 million).

Distributions to Class B units

On January 23, 2018, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $15 million which amount was paid on February 13, 2018. In 2017, the Class B distribution was $22 million. The Class B distribution represents an amount based upon 30 percent of GTN's distributable cash flow exceeding certain annual thresholds.

Please read Notes 7, 10, 13 and 14 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more detailed disclosures on the Class B units.

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)	**2017**	2016[(a)]	2015[(a)]	2014[(a)]	2013[(a)(b)]
Income Data (for the year ended December 31)					
Transmission revenues	**422**	426	417	410	410
Equity earnings[(c)]	**124**	97	97	88	67
Impairment of equity-method investment[(d)]	**–**	–	(199)	–	–
Net income	**263**	263	58	241	221
Net income (loss) attributable to controlling interests	**252**	248	37	195	174
Basic and diluted net (loss) income per common unit	**$3.16**	$3.21[(e)]	$(0.03)[(e)]	$2.67[(e)]	$2.13[(e)]
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$3.94**	$3.71	$3.51	$3.33	$3.21
Balance Sheet Data (at December 31)					
Total assets	**3,559**	3,354	3,459[(f)]	3,802[(f)]	3,867[(f)]
Long-term debt (including current maturities)	**2,403**	1,911	1,971[(f)]	1,778[(f)]	1,679[(f)]
Partners' equity	**1,068**	1,272	1,391	1,818	2,013

(a) Recast information to consolidate PNGTS for all periods presented as a result of an additional 11.81 percent in PNGTS that was acquired from a subsidiary of TransCanada on June 1, 2017. Prior to this transaction, the Partnership owned a 49.9 percent interest in PNGTS that was acquired from TransCanada on January 1, 2016. Please read Note 2 – Significant Accounting policies-Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules"

(b) Recast information to consolidate GTN and Bison for all periods presented as a result of additional 45 percent membership interests in each of GTN and Bison that were acquired from subsidiaries of TransCanada in 2013 resulting in a 70 percent ownership in each. Please read Note 2, Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules"

(c) Equity earnings represent our share in investee's earnings and do not include any impairment charge on our equity investments.

(d) During the fourth quarter of 2015, we recognized an impairment charge on our investment in Great Lakes amounting to $199 million. No other impairment was recognized during the periods presented. The equity earnings as presented in 2015 did not include this impairment charge. Please read Note 5-Equity Investments, Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules"

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

(f) As a result of the application of Accounting Standards Update (ASU) No. 2015-03 "Interest-Imputation of Interest" and similar to the presentation of debt discounts, debt issuance costs previously reported as other assets in the balance sheet were reclassified as an offset against their respective debt liabilities.

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

Management's Discussion and Analysis (MD&A) 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. This MD&A should be read in conjunction with the accompanying December 31, 2017 audited financial statements and notes included in Part IV within Item 15. "Exhibits and Financial Statement Schedules". Our discussion and analysis includes the following:

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

BASIS OF PRESENTATION

See Note 2 of the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules", for important information on the content and comparability of our historical financial statements.

The initial acquisition of a 49.9 percent interest in PNGTS on January 1, 2016 and additional 11.81 percent on June 1, 2017 (collectively, the PNGTS Acquisitions) were accounted for as transaction between entities under common control, which are required to be accounted for as if the PNGTS Acquisitions had occurred at the beginning of the year, with financial statements for prior periods recast to furnish comparative information. Accordingly, the accompanying historical financial information has been recast, except net income (loss) per common unit, to consolidate PNGTS for all periods presented.

Also, on June 1, 2017, the Partnership acquired from subsidiaries of TransCanada a 49.34 percent interest in Iroquois (Refer to Note 7 of the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules"). This transaction was accounted prospectively and formed part of the accompanying financial information effective June 1, 2017.

EXECUTIVE OVERVIEW

Net income attributable to controlling interests was $252 million or $3.16 per common unit in 2017 compared to income of $248 million, or $3.21 per common unit in 2016. Net income attributable to controlling interests increased by $4 million in 2017 compared to 2016. Cash distributions declared per common unit increased by six percent from $3.71 per common unit in 2016 to $3.94 per common unit in 2017.

Our EBITDA increased by three percent to $445 million and Distributable cash flow decreased by one percent to $310 million. Please see "Non-GAAP Financial Measures: EBITDA, Adjusted EBITDA and Distributable Cash Flow" for more information.

Outlook of Our Business

TransCanada, the ultimate parent company of our General Partner, is currently advancing CAD $23 billion of near-term capital projects, together with a number of other larger, commercially secured initiatives. TransCanada continues to view us as a core element of its strategy and we continue to expect to play a meaningful role in funding a portion of TransCanada's near-term capital growth program depending on market conditions and TransCanada's financing needs.

Our focus remains on the optimization of our asset portfolio and may include organic growth over time. We will continue to advance business opportunities over time that fit within our geographic footprint and invest in the ongoing safe and reliable operations of our pipeline assets.

Over the near term, we expect our assets to perform consistently due to high contract levels, positive market fundamentals and regulatory stability. The recent long-term contract between Great Lakes and TransCanada provides long-term contract stability for Great Lakes. Other opportunities for recontracting and expansion exist throughout our portfolio, including further benefits on GTN from upstream debottlenecking activities on related TransCanada pipelines. Continued high rates of utilization of our pipelines may require somewhat higher levels of investment in maintenance compared to recent years, but we expect that these investments will be reflected in rates in future years.

HOW WE EVALUATE OUR OPERATIONS

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

EBITDA

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

Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit

During 2015, we have evaluated our financial performance and position inclusive of the impairment charge to our investment in Great Lakes recognized during the fourth quarter 2015. However, we believe it is not reflective of the results of underlying operations during the period. Therefore, in 2015, we presented Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit as non-GAAP measures that excluded the impact of the $199 million non-cash impairment charge.

For the years ended December 31, 2017 and 2016, we do not have any similar adjustments in EBITDA, earnings or earnings per common unit. Accordingly, for the years ended December 31, 2017 and 2016, our EBITDA is the same as Adjusted EBITDA and our GAAP earnings and GAAP earnings per common unit were not adjusted.

Distributable Cash Flows

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

Please see "Non-GAAP Financial Measures: EBITDA, Adjusted EBITDA and Distributable Cash Flow" for more information.

RESULTS OF OPERATIONS

The ownership interests we have in our pipeline assets were our only material sources of income during the periods presented. Therefore, our results of operations and cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems.

Year Ended December 31, 2017 Compared with the Year Ended December 31, 2016

(unaudited) *(millions of dollars, except per common unit amounts)*	**2017**	2016[a]	$ Change[d]	% Change[c]
Transmission revenues	**422**	426	(4)	(1)
Equity earnings	**124**	97	27	28
Operating, maintenance and administrative	**(103)**	(92)	(11)	(12)
Depreciation	**(97)**	(96)	(1)	(1)
Financial charges and other	**(82)**	(71)	(11)	(15)
Net income before taxes	**264**	264	–	–
Income taxes	**(1)**	(1)	–	–
Net Income	**263**	263	–	–
Net income attributable to non-controlling interests	**11**	15	4	27
Net income attributable to controlling interests	**252**	248	4	2
Net income per common unit	**3.16**	3.21[b]	(0.05)	(2)

(a) Financial information was recast to consolidate PNGTS for all periods presented. Please see "Basis of Presentation" section for more information.

(b) Net income per common unit prior to recast.

(c) Positive number represents a favorable change; bracketed or negative number represents an unfavorable change.

Net income attributable to controlling interests increased by $4 million to $252 million in 2017 compared to $248 million in 2016, resulting in net income per common unit during the year of $3.16 after allocations to the General Partner and to the Class B units. Overall, 2017 is comparable to 2016 primarily due to the net effect of the following:

Transmission revenues – The $4 million decrease was primarily due to lower contracted and discretionary revenues on PNGTS and lower transportation rates on Tuscarora as a result of the settlement reached with its customers effective August 1, 2016 partially offset by higher discretionary revenues on short-term services sold by GTN and North Baja.

Equity earnings – The $27 million increase was primarily due to the addition of equity earnings from Iroquois, effective June 1, 2017.

Operating, maintenance and administrative costs – The $11 million increase was mainly attributable to higher pipeline integrity costs on GTN and overall higher allocated management and operational expenses on our pipeline systems as performed by TransCanada.

Financial charges and other – The $11 million increase was mainly attributable to additional borrowings to finance the 2017 Acquisition.

Net-income attributable to non-controlling interests – The Partnership had a net decrease amounting to $4 million primarily due to lower earnings from PNGTS as a result of its lower revenues.

Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015

(unaudited) *(millions of dollars, except per common unit amounts)*	**2016[a]**	2015[a]	$ Change[d]	% Change[d]
Transmission revenues	**426**	417	9	2
Equity earnings	**97**	97	–	–
Impairment of equity-method investment	**–**	(199)	199	100
Operating, maintenance and administrative	**(92)**	(97)	5	5
Depreciation	**(96)**	(95)	(1)	(1)
Financial charges and other	**(71)**	(63)	(8)	13
Net income before taxes	**264**	60	204	*
Income taxes	**(1)**	(2)	1	50
Net Income	**263**	58	205	*
Net income attributable to non-controlling interests	**15**	21	6	29
Net income attributable to controlling interests	**248**	37	211	*
Adjusted earnings[b]	**248**	236	12	5
Net income (loss) per common unit[c]	**3.21**	(0.03)	3.24	*
Adjusted earnings per common unit[b]	**3.21**	3.03	0.18	6

(a) Financial information was recast to consolidate PNGTS. Please see "Basis of Presentation" section for more information.

(b) Adjusted earnings and Adjusted earnings per common unit are non-GAAP measures for which reconciliations to the appropriate GAAP measures are provided for below.

(c) Net income (loss) per common unit prior to recast.

(d) Positive number represents a favorable change; bracketed or negative number represents an unfavorable change.

* Change is greater than 100 percent.

Net income attributable to controlling interests increased by $211 million to $248 million in 2016 compared to $37 million in 2015, resulting in net income per common unit during the year of $3.21 after allocations to the General Partner and to the Class B units. This increase was primarily the result of the recognition of a $199 million non-cash impairment charge to our investment in Great Lakes in fourth quarter 2015 which lowered our net income attributable to controlling interests in 2015. (See Critical Accounting Estimates – Impairment of Equity Investments, Goodwill and Long-Lived Assets – Equity Investments section for more information.)

The Partnership's Adjusted earnings were higher by $12 million in 2016 compared to 2015, an increase of $0.18 per common unit mainly due to the following:

Transmission revenues – increase of $9 million primarily due to the net effect of:

- higher discretionary revenues on GTN from short-term services sold to its customers;
- lower discretionary revenues on PNGTS from short-term services sold to its customers;
- full year of revenues from GTN's Carty lateral system which was placed into service in October 2015; and
- lower transportation rates on GTN as a result of the settlement reached with its customers effective July 1, 2015.

Operating, maintenance and administrative – generally lower expenses in 2016 as a result of lower operational costs on our consolidated entities. Additionally, dropdown costs were incurred in 2015 related to the acquisition of the initial 49.9 percent interest in PNGTS.

Financial charges and other – $8 million increase primarily due to the net effect of:

- additional borrowings to fund a portion of our recent acquisitions
- lower interest incurred by PNGTS as a result of its 2016 principal payments on its long term debt
- no interest was incurred in 2016 on PNGTS' rate refund liability due to the payment of all of PNGTS' outstanding rate refund liability on April 15, 2015. (Refer to Note 2 – Significant Accounting Policies – Revenue Recognition section, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules")

Net income attributable to non-controlling interests – $6 million decrease primarily due to the Partnership's 100 percent ownership in GTN effective April 1, 2015.

Non-GAAP Financial Measures: Adjusted earnings and Adjusted earnings per common unit

Reconciliation of Net income attributable to controlling interests to Adjusted earnings

(millions of dollars) Year ended December 31	**2017**	2016	2015
Net income attributable to controlling interests	**252**	248	37
Add: Impairment of equity-method investment	**–**	–	199
Adjusted earnings	**252**	248	236

Reconciliation of Net income per common unit to Adjusted earnings per common unit

Year ended December 31	**2017**	2016	2015
Net income (loss) per common unit-basic and diluted[b]	**3.16**	3.21[a]	(0.03)[a]
Add: per unit impact of impairment of equity-method investment[c]	**–**	–	3.06
Adjusted earnings per common unit	**3.16**	3.21	3.03

(a) Net income per common unit prior to recast.

(b) See also Note 13 of the Partnership's consolidated financial statements included in Part IV. Item 15. 'Exhibits and Financial Statement Schedules" for details of the calculation of net income per common unit.

(c) 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.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity and cash flows include distributions received from our equity investments, operating cash flows from our 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 (including those distributions made to TransCanada through our General Partner and as holder of all our Class B units) primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity. 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. We expect to be able to fund our liquidity and capital resource requirements, including our distributions and required debt repayments, at the Partnership level over the next 12 months utilizing our cash flow and, if required, our existing Senior Credit Facility. The following table sets forth the available borrowing capacity under the Partnership's Senior Credit Facility:

(unaudited) *(millions of dollars)* *December 31*	**2017**	2016	2015
Total capacity under the Senior Credit Facility	**500**	500	500
Less: Outstanding borrowings under the Senior Credit Facility	**185**	160	200
Available capacity under the Senior Credit Facility	**315**	340	300

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. Additionally, on September 1, 2017, the Partnership made an equity contribution to Northern Border of $83 million. This amount represents the Partnership's 50 percent share of a one time $166 million capital contribution request from Northern Border to reduce the outstanding balance of its revolver debt to increase its available borrowing capacity.

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.

Summarized Cash Flow

Year Ended December 31, *(millions of dollars)*	**2017**	2016[a]	2015[a]
Net cash provided by (used in):			
Operating activities	**376**	417	260
Investing activities	**(761)**	(230)	(326)
Financing activities	**354**	(178)	(32)
Net increase in cash and cash equivalents	**(31)**	9	(98)
Cash and cash equivalents at beginning of the period	**64**	55	153
Cash and cash equivalents at end of the period	**33**	64	55

(a) Financial information was recast to consolidate PNGTS. Please see "Basis of Presentation" section for more information.

Cash Flow Analysis for the Year Ended December 31, 2017 compared to Same Period in 2016

Operating Cash Flows

Net cash provided by operating activities decreased by $41 million in the twelve months ended December 31, 2017 compared to the same period in 2016 primarily due to:

- lower cash generated from operating activities of our subsidiaries primarily due to its lower revenues and higher operating costs as discussed in "Results of Operations" section;
- higher financing costs incurred as a result of the 2017 Acquisition; and
- lower distributions from Great Lakes and Northern Border in 2017 partially offset by distributions received from Iroquois, resulting from the addition of Iroquois to our portfolio of assets effective June 1, 2017. Distributions received in the first quarter of 2016 from Great Lakes were higher than distributions received in the first quarter of 2017 on a run-rate basis due to the resolution of certain regulatory proceedings in the fourth quarter of 2015 which inflated its results during that period and resulted in higher cash flow. The increase in cash flow was paid to the Partnership in the first quarter of 2016 and was not applicable in the first quarter of 2017. Additionally, the Partnership received lower distributions from Northern Border in 2017 compared to the same period in 2016 primarily due to higher maintenance capital expenditures during the current 2017 period together with the change in Northern Border's distribution policy during 2016 from a lagged quarterly distribution to a more timely monthly distribution that resulted in a larger distribution in the second quarter of 2016.

Investing Cash Flows

Net cash used in investing activities increased by $531 million in the twelve months ended December 31, 2017 compared to the same period in 2016. On June 1, 2017, we invested $593 million to acquire a 49.34 percent interest in Iroquois and $53 million to acquire an additional 11.81 percent of PNGTS. Additionally, on September 1, 2017, we contributed $83 million to Northern Border representing our 50 percent share of a requested capital contribution to reduce the outstanding balance of its revolving credit facility. During 2017, we also received a $5 million distribution from Iroquois as a return of surplus cash on their balance sheet. Together, these transactions resulted in the net increase of $531 million compared to 2016 where we invested $193 million on January 1, 2016 to acquire a 49.9 percent interest in PNGTS.

Financing Cash Flows

The net change in cash from our financing activities was approximately $532 million in the twelve months ended December 31, 2017 compared to the same period in 2016 primarily due to the net effect of:

- $552 million increase in net issuances of debt in 2017 primarily to finance the 2017 Acquisition;
- $34 million increase in distributions paid to our common units and to our General Partner in respect of its two percent general partner interest and IDRs;

- $10 million increase in distributions paid to Class B units in 2017 as compared to 2016;
- $9 million increase in our At-the-market (ATM) equity issuances in 2017 as compared to 2016;
- $7 million decrease in distributions paid to non-controlling interest due to lower revenues on PNGTS compared to the previous periods; and
- $8 million decrease in distributions paid to TransCanada as the former parent of PNGTS primarily due to the Partnership's acquisition of a 49.9 percent interest in PNGTS effective January 1, 2016 and additional 11.81 percent effective June 1, 2017.

Cash Flow Analysis for the Year Ended December 31, 2016 compared to Same Period in 2015

Operating Cash Flows

Net cash provided by operating activities increased by $157 million in the twelve months ended December 31, 2016 compared to the same period in 2015 primarily due to the net effect of:

- higher earnings as discussed in more detail in the "Results of Operations" section.
- higher distributed earnings received from equity investments in 2016 as a result of additional revenues from new contracts with ANR Pipeline Company (ANR), a related party
- payment of all of PNGTS' outstanding rate refund liability in 2015, including interest as a result of its rate case settlement approved by FERC on February 2015. Total refunds accumulated to $114 million, including $8 million of interest, and were paid to customers on April 15, 2015. (Refer to Note 2 – Significant Accounting Policies – Revenue Recognition section, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules") and
- timing of working capital changes. The majority of the timing impact relates to the settlement of our accounts payable and accrued liabilities.

Investing Cash Flows

Net cash used in investing activities decreased by $96 million in the twelve months ended December 31, 2016 compared to the same period in 2015 as we invested a lesser amount on our initial 49.9 percent acquisition of interest in PNGTS compared to our investment during the same period in 2015. In 2015, we paid $264 million to acquire the remaining 30 percent interest in GTN compared to $193 million paid for the acquisition of a 49.9 percent interest in PNGTS in 2016. Additionally, we had higher capital expenditures in 2015 due to expenditures related to the construction of the Carty Lateral.

Financing Cash Flows

Net cash used in financing activities increased by $146 million in the twelve months ended December 31, 2016 compared to the same period in 2015 primarily due to the net effect of:

- $254 million decrease in net issuances of debt in 2016 as compared with 2015;
- $123 million increase in our ATM equity issuances in 2016 as compared with 2015;
- $22 million increase in distributions paid to our common units including our General Partner's effective two percent share and its related IDRs;
- $12 million of distributions paid to Class B units in 2016;
- $9 million decrease in distributions paid to non-controlling interest due to the Partnership's 100 percent ownership in GTN effective April 1, 2015; and
- $10 million decrease in distributions paid to TransCanada as the former parent of PNGTS due to the Partnership's acquisition of a 49.9 percent interest in PNGTS effective January 1, 2016.

Capital spending

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)* *(unaudited)*	**2017**	2016[(a)]	2015[(a)]
Maintenance	**63**	31	21
Growth	**3**	5	54
Total[(b)]	**66**	36	75

(a) Financial information was recast to reflect our 61.71 percent share of PNGTS' capital spending for all periods presented however, PNGTS did not incur significant capital expenditures in 2016 and 2015. Please see "Basis of Presentation" section for more information.

(b) Total maintenance and growth capital expenditures as reflected in this table include amounts attributable to the Partnership's proportionate share of maintenance and growth capital expenditures of the Partnership's equity investments, which are not reflected in our total capital expenditures as presented in our consolidated statement of cash flows. Additionally, our proportionate share includes accrued capital expenditures during the period.

Year Ended December 31, 2017 Compared with the Year Ended December 31, 2016

Maintenance capital spending increased by $32 million in 2017 compared to 2016 mainly due to overhauls and pipeline integrity projects on GTN in addition to continuing compressor station overhauls that began in 2016 on Northern Border.

Capital expenditures on growth projects were comparable between 2017 and 2016.

Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015

Maintenance capital spending increased by $10 million in 2016 compared to 2015 mainly due to major overhauls conducted in 2016 on Northern Border and Great Lakes and costs related to pipe integrity on Great Lakes and North Baja.

In 2015, The Partnership incurred significant spending related to the construction of Carty Lateral. No such significant project occurred in 2016.

Cash Flow Outlook

Operating Cash Flow Outlook

Northern Border declared its December 2017 distribution of $15 million on January 8, 2018, of which the Partnership received its 50 percent share or $7 million on January 31, 2018.

Northern Border declared its January 2018 distribution of $17 million on February 14, 2018, of which the Partnership will receive its 50 percent share or $9 million on February 28, 2018.

Great Lakes declared its fourth quarter 2017 distribution of $20 million on January 10, 2018, of which the Partnership received its 46.45 percent share or $9 million on February 1, 2018.

Iroquois declared its fourth quarter 2017 distribution of $29 million on January 22, 2018, of which the Partnership received its 49.34 percent share or $14 million on February 1, 2018.

Investing Cash Flow Outlook

The Partnership expects to make a $9 million contribution in 2018 to fund debt repayments of Great Lakes which is consistent with prior years.

In 2018, our pipeline systems expect to invest approximately $76 million in maintenance of existing facilities and approximately $27 million in growth projects, of which the Partnership's share would be $53 million and $15 million, respectively. Our consolidated entities have commitments of $4 million as of December 31, 2017 in connection with various maintenance and general plant projects.

Financing Cash Flow Outlook

On January 23, 2018, the board of directors of our General Partner declared the Partnership's fourth quarter 2017 cash distribution in the amount of $1.00 per common unit which was paid on February 13, 2018 to unitholders of record as of February 2, 2018. The total amount of cash distribution paid to common unitholders and General Partner was $76 million.

On January 23, 2018, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $15 million which was paid on February 13, 2018. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2017 less the threshold level of $20 million. For 2018, the threshold level is the same and we anticipate such threshold will be exceeded in the third quarter of 2018.

Please read Notes 7, 10, 13 and 14, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules".

The approximately $80 million PXP project, as further discussed in Part 1, Item 1. Business-Recent Business Developments, is expected to be financed through a new credit facility at PNGTS.

Non-GAAP Financial Measures: EBITDA, Adjusted 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 most comparable measure of net income. It measures our earnings before deducting interest, taxes, depreciation and amortization, net income attributable to non-controlling interests, and it includes earnings from our equity investments.

Our Adjusted EBITDA in 2015 excludes the impact of the $199 million non-cash impairment charge we recognized on our investment in Great Lakes. We believe the charge is significant but not reflective of our underlying operations. For the years ended December 31, 2017 and 2016, we do not have any similar adjustments in EBITDA. Accordingly, for the years ended December 31, 2017 and 2016 our EBITDA is the same as Adjusted EBITDA.

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 our Adjusted EBITDA *plus:*

- Distributions from our equity investments

  less:

- Earnings from our equity investments,
- Equity allowance for funds used during construction (Equity AFUDC),
- Interest expense,
- Income taxes,
- Distributions to non-controlling interests,
- Distributions to TransCanada as former parent of PNGTS, 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 years ended December 31, 2017 and December 31, 2016, less $20 million (2015 – less $15 million).

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

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 information prepared in accordance with GAAP. Additionally, these measures as presented may not be comparable to similarly titled measures of other companies.

Reconciliations of Net Income to EBITDA, Adjusted EBITDA and Distributable Cash Flow

The following table presents a reconciliation of the non-GAAP financial measures of EBITDA, Adjusted EBITDA and Distributable Cash Flow, to the GAAP financial measure of net income.

Year Ended December 31 *(unaudited)* *(millions of dollars)*	**2017**	2016[a]	2015[a]
Net income	**263**	263	58
Add:			
Interest expense[b]	**84**	73	68
Depreciation and amortization	**97**	96	95
Income taxes	**1**	1	2
EBITDA	**445**	433	223
Impairment of equity investment	**–**	–	199
ADJUSTED EBITDA	**445**	433	422
Add:			
Distributions from equity investments[c]			
Northern Border	**82**	91	91
Great Lakes	**38**	34	40
Iroquois	**41**[d]	–	–
	161	125	131
Less:			
Equity earnings:			
Northern Border	**(67)**	(69)	(66)
Great Lakes	**(31)**	(28)	(31)
Iroquois	**(26)**	–	–
	(124)	(97)	(97)
Less:			
Equity AFUDC	**–**	–	(1)
Interest expense[b]	**(84)**	(73)	(68)
Income taxes	**(1)**	(1)	(2)
Distributions to non-controlling interests[e]	**(14)**	(18)	(29)
Distributions to TransCanada as PNGTS' former parent[f]	**(2)**	(6)	(30)
Maintenance capital expenditures[g]	**(38)**	(16)	(16)
	(139)	(114)	(146)
Total Distributable Cash Flow	**343**	347	310
General Partner distributions declared[h]	**(18)**	(12)	(8)
Distributions allocable to Class B units[i]	**(15)**	(22)	(12)
Distributable Cash Flow	**310**	313	290

(a) Financial information was recast to consolidate PNGTS. Please see "Basis of Presentation" section for more information.

(b) Interest expense as presented includes net realized loss related to the interest rates swaps and amortization of realized loss on PNGTS' derivative instruments (Refer to Notes 12 and 19, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules").

(c) These amounts 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.

(d) This amount represents our proportional 49.34 percent share of the distribution declared by our equity investee Iroquois from the second to fourth quarter of 2017 and includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $8 million for the seven months ended December 31, 2017. (Refer to Notes 5 and 7, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules").

(e) Distributions to non-controlling interests represent the respective share of our consolidated entities' distributable cash not owned by us during the periods presented.

(f) Distributions to TransCanada as PNGTS' former parent represent TransCanada's respective share of PNGTS' distributable cash not owned by us during the periods presented.

(g) The Partnership's maintenance capital expenditures include expenditures made to maintain, over the long term, our assets' operating capacity, system integrity and reliability. Accordingly, this amount represents the Partnership's and its consolidated subsidiaries' maintenance capital expenditures and does not include the Partnership's share of maintenance capital expenditures on our equity investments. Such amounts are reflected in "Distributions from equity investments" as those amounts are withheld by those entities from their quarterly distributable cash.

Please read the Capital spending section for more information regarding the Partnership's total proportionate share of maintenance capital expenditures from our consolidated entities and equity investments.

(h) Distributions declared to the General Partner for the year ended December 31, 2017 included an incentive distribution of approximately $12 million (2016 – $7 million; 2015 – $3 million).

(i) During the twelve months ended December 31, 2017, 30 percent of GTN's total distributions was $35 million; therefore, the distributions allocable to the Class B units was $15 million, representing the amount that exceeded the threshold level of $20 million. During the twelve months ended December 31, 2016, 30 percent of GTN's total distributions was $42 million; therefore, the distributions allocable to the Class B units was $22 million, representing the amount that exceeded the threshold level of $20 million. During the twelve months ended December 31, 2015, 30 percent of GTN's total distributions was $27 million; therefore, the distributions allocable to the Class B units was $12 million, representing the amount that exceeded the threshold level of $15 million. The Class B distribution is determined and payable annually.

On January 23, 2018, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $15 million which was paid on February 13, 2018. The 2016 Class B distribution amounting to $22 million was paid by the Partnership on February 14, 2017. Please read Notes 7,10,13 and 14, Notes to Consolidated Financial Statements for the year ended December 31, included in Part IV within Item 15. "Exhibits and Financial Statement Schedules".

Year Ended December 31, 2017 Compared with the Year Ended December 31, 2016

Our EBITDA and Adjusted EBITDA was $12 million higher primarily due to the addition of equity earnings from Iroquois effective June 1, 2017 offset by lower revenues and an increase in operational costs on our subsidiaries as discussed in more detail under the "Results of Operations" section.

Our distributable cash flow for the twelve months ended December 31, 2017 was comparable to same period in 2016 due to the net effect of:

- the addition of our 49.34 percent share of distributions declared by Iroquois from the second to fourth quarter of 2017;
- lower revenues from our subsidiaries and increases in their operational costs as previously discussed above in "Results of Operations";
- higher financing costs as a result of the 2017 Acquisition;
- higher maintenance capital expenditures related to major compression equipment overhauls on GTN's pipeline system;
- lower distributable cash flow from Northern Border primarily due to its higher operating costs and higher maintenance capital expenditures;
- higher distributions declared in respect of our IDRs during 2017; and
- lower distributions allocable to the Class B units during 2017.

Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015

EBITDA increased by $210 million to $433 million in 2016 compared to $223 million in 2015. The increase was primarily the result of the recognition of a $199 million non-cash impairment charge in 2015 to our investment in Great Lakes which lowered EBITDA in 2015 accordingly (See Critical Accounting Estimates – Impairment of Equity Investments, Goodwill and Long-Lived Assets – Equity Investments section for more information.)

Adjusted EBITDA increased by $11 million compared to the same period in 2015 mainly due to higher transmission revenues as discussed in more detail in the Results of Operations section.

Distributable cash flow increased by $23 million in the twelve months ended December 31, 2016 compared to the same period in 2015 primarily due to the net effect of:

- the cash impact of higher Adjusted EBITDA;
- lower distributable cash flow from our equity investments as a result of higher maintenance capital in 2016 as discussed in more detail on the "Capital Spending" section;
- lower distributions paid to non-controlling interests due to the Partnership owning 100 percent of GTN effective April 1, 2015;
- lower distributable cash flow allocable to TransCanada as the former parent of PNGTS due to the Partnership's acquisition of 49.9 percent interest in PNGTS from TransCanada effective January 1, 2016;
- higher interest expense related to higher borrowings as a result of the recent acquisitions offset by;
- higher General Partner distributions due to higher IDRs in the current period; and
- higher distributions allocable to the Class B units during the current period.

Contractual Obligations

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2017 included the following:

(unaudited) *(millions of dollars)*	Total	Payments Due by Period Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Year Ended December 31, 2017
TC PipeLines, LP						
Senior Credit Facility due 2021	185	–	–	185	–	2.41%
2013 Term Loan Facility due 2022	500	–	–	500	–	2.33%
2015 Term Loan Facility due 2020	170	–	170	–	–	2.22%
4.65% Senior Notes due 2021	350	–	–	350	–	4.65%(a)
4.375% Senior Notes due 2025	350	–	–	–	350	4.375%(a)
3.90% Senior Notes due 2027	500	–	–	–	500	3.90%(a)
GTN						
5.29% Unsecured Senior Notes due 2020	100	–	100	–	–	5.29%(a)
5.69% Unsecured Senior Notes due 2035	150	–	–	–	150	5.69%(a)
Unsecured Term Loan Facility due 2019	55	20	35	–	–	2.02%
PNGTS						
5.90% Senior Secured Notes due 2018	30	30	–	–	–	5.90%(a)
Tuscarora						
Unsecured Term Loan due 2020	25	1	24	–	–	2.27%
	2,415	51	329	1,035	1,000	

(a) Fixed Rate debt

(b) Interest payments on floating-rate debt are estimated using interest rates effective as of December 31, 2017.

TC PipeLines, LP

On November 10, 2016, the Partnership's Senior Credit Facility was amended to extend the maturity period through November 10, 2021. The Facility consists of a $500 million senior revolving credit facility with a banking syndicate, under which $185 million was outstanding at December 31, 2017 (December 31, 2016 – $160 million), leaving $315 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 $500 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 was 2.62 percent at December 31, 2017 (December 31, 2016 – 1.92 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 originally on July 1, 2018. On September 29, 2017, the Partnership's 2013 Term Loan Facility was amended to extend the maturity period through October 2, 2022. 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 2.00 percent for LIBOR borrowings and 0.125 percent and 1.00 percent for base rate borrowings.

As of December 31, 2017, the variable interest rate exposure related to 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 2.31 percent (2016-2.31 percent). Prior to hedging activities, the LIBOR-based interest rate was 2.62 percent at December 31, 2017 (December 31, 2016 – 1.87 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. On September 29, 2017, the Partnership's 2015 Term Loan Facility that was due on October 1, 2018 was amended to extend the maturity period through October 1, 2020. The LIBOR-based interest rate on the 2015 Term Loan Facility was 2.51 percent at December 31, 2017 (December 31, 2016 – 1.77 percent).

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]) no greater than 5.00 to 1.00 for each fiscal quarter, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the leverage ratio is to be no greater than 5.50 to 1.00. The leverage ratio was 4.70 to 1.00 as of December 31, 2017.

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 2015 GTN Acquisition (refer to Note 7) and to reduce the amount outstanding under our Senior Credit Facility. The indenture for the notes contains customary investment grade covenants.

On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 Acquisition (Refer to Note 7). The indenture for the notes contains customary investment grade covenants.

PNGTS

PNGTS' Senior Secured Notes are secured by the PNGTS long-term firm shipper contracts and its partners' pledge of their equity and a guarantee of debt service for six months. PNGTS is restricted under the terms of its note purchase agreement from making cash distributions unless certain conditions are met. Before a distribution can be made, the debt service reserve account must be fully funded and PNGTS' debt service coverage ratio for the preceding and succeeding twelve months must be 1.30 or greater. At December 31, 2017, the debt service coverage ratio was 1.72 for the twelve preceding months and 1.53 for the twelve succeeding months. Therefore, PNGTS was not restricted to make any cash distributions.

GTN

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 was 2.31 percent at December 31, 2017 (December 31, 2016 – 1.57 percent). 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, 2017 is 44.6 percent.

Tuscarora

On August 21, 2017, Tuscarora refinanced all of its outstanding debt by amending its existing Unsecured Term Loan Facility and issuing a new $25 million variable rate term loan that will require yearly principal payments and will mature on August 21, 2020. Tuscarora's Unsecured Term Loan contains a covenant that requires Tuscarora to maintain a debt service coverage ratio (cash available from operations divided by a sum of interest expense and principal payments) of greater than or equal to 3.00 to 1.00. As of December 31, 2017, the ratio was 11.09 to 1.00.

The LIBOR-based interest rate on the Tuscarora's Unsecured Term Loan Facility was 2.49 percent at December 31, 2017 (December 31, 2016 – 1.90 percent).

Partnership (TC PipeLines, LP and its subsidiaries)

At December 31, 2017, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

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, 2017 was $2,475 million. As of February 26, 2018, the Partnership had $170 million outstanding under the Senior Credit Facility.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2017 included the following:

(unaudited) *(millions of dollars)*	Total	Payments Due by Period[a] Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
7.50% Senior Notes due 2021	250	–	–	250	–
$200 million Credit Agreement due 2020	15	–	15	–	–
Interest payments on debt	74	20	39	15	–
Other commitments[b]	53	3	5	5	40
	392	23	59	270	40

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

(b) Future minimum payments for office space and rights-of-way commitments.

Northern Border has commitments of $7 million as of December 31, 2017 in connection with various pipeline, metering and overhaul projects.

At December 31, 2017, the aggregate estimated fair value of Northern Border's long-term debt was approximately $294 million (2016 – $464 million). In 2017, interest expense related to the senior notes was $19 million (2016 – $23 million; 2015 – $25 million).

Senior Notes

Northern Border's outstanding debt securities are senior unsecured notes. 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, 2017, Northern Border was in compliance with all of its financial covenants.

Credit Agreement

Northern Border's credit agreement consists of a $200 million revolving credit facility. At December 31, 2017, $15 million was outstanding leaving $185 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, 2017 was 2.12 percent (2016 – 1.90 percent). At December 31, 2017, Northern Border was in compliance with all of its financial covenants.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations as of December 31, 2017 included the following:

(unaudited) *(millions of dollars)*	Total	Payments Due by Period[a] Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.73% series Senior Notes due 2016 to 2018	9	9	–	–	–
9.09% series Senior Notes due 2016 to 2021	40	10	20	10	–
6.95% series Senior Notes due 2019 to 2028	110	–	22	22	66
8.08% series Senior Notes due 2021 to 2030	100	–	–	20	80
Interest payments on debt	120	20	34	26	40
	379	39	76	78	186

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

Great Lakes has commitments of $3 million as of December 31, 2017 in connection with compressor overhaul projects.

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 $139 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2017 (2016 – $150 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2017.

The aggregate estimated fair value of Great Lakes' long-term debt was $335 million at December 31, 2017 (2016 – $354 million). The aggregate annual required repayment of senior notes is $19 million for 2018, $21 million for each year 2019 and 2020, $31 million for 2021 and $21 million for 2022. Aggregate required repayments of senior notes thereafter total $146 million. In 2017, interest expense related to Great Lakes' senior notes was $21 million (2016 – $22 million; 2015 – $24 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. At December 31, 2017 and 2016, Great Lakes has an outstanding receivable from this arrangement amounting to $64 million and $27 million, respectively.

Summary of Iroquois' Contractual Obligations

Iroquois' contractual obligations as of December 31, 2017 included the following:

		Payments Due by Period[a]			
(unaudited) *(millions of dollars)*	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
6.63% series Senior Notes due 2019	140	–	140	–	–
4.84% series Senior Notes due 2020	150	–	150	–	–
6.10% series Senior Notes due 2027	39	4	9	7	19
Interest payments on debt	43	19	18	3	3
Transportation by others[b]	15	3	6	6	–
Operating leases	7	1	3	1	2
Pension contributions[c]	1	1	–	–	–
	395	28	326	17	24

(a) Represents 100 percent of Iroquois' contractual obligations.

(b) Rates are based on known 2018 levels. Beyond 2018, demand rates are subject to change.

(c) Pension contributions cannot be reasonably estimated by Iroquois beyond 2018.

Iroquois has commitments of $2 million as of December 31, 2017 relative to procurement of materials on its expansion project.

During the third quarter of 2017, Iroquois' partners adopted a distribution resolution to address the surplus cash on Iroquois' balance sheet. Under the terms of the resolution, Iroquois is expected to distribute approximately $57.6 million of unrestricted cash to its partners over 11 quarters, which began with Iroquois' second quarter 2017 distribution on August 1, 2017. As of February 26, 2018, Iroquois has distributed approximately $15.7 million of the expected $57.6 million, of which our proportionate share was approximately $7.8 million. Please read Note 7, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules"

Iroquois is restricted under the terms of its note purchase agreement from making cash distributions to its partners unless certain conditions are met. Before a distribution can be made, the debt/capitalization ratio must be below 75% and the debt service coverage ratio must be at least 1.25 times for the four preceding quarters. At December 31, 2017, the debt/capitalization ratio was 47.4% and the debt service coverage ratio was 5.52 times, therefore, Iroquois was not restricted from making any cash distributions.

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.

		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
1/22/2015	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	2/12/2016	$0.89	$57	$12[(d)]	$1	$1	$71
4/21/2016	5/13/2016	$0.89	$58	$–	$1	$1	$60
7/21/2016	8/12/2016	$0.94	$62	$–	$1	$2	$65
10/20/2016	11/14/2016	$0.94	$63	$–	$1	$2	$66
1/23/2017	2/14/2017	$0.94	$64	$22[(e)]	$2	$2	$90
4/25/2017	5/15/2017	$0.94	$65	$–	$1	$2	$68
7/20/2017	8/11/2017	$1.00	$69	$–	$2	$3	$74
10/24/2017	11/14/2017	$1.00	$70	$–	$1	$3	$74
1/23/2018[(b)]	2/13/2018[(b)]	$1.00	$71	$15[(f)]	$2	$3	$91

(a) The distributions paid during the year ended December 31, 2017 included incentive distributions to the General Partner of $10 million (2016 – $6 million, 2015 – $2 million).

(b) On February 13, 2018, we paid a cash distribution of $1.00 per unit on our outstanding common units to unitholders of record at the close of business on February 2, 2017. Please read Note 14, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules"

[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 exceeding certain annual thresholds. Please read Notes 7, 10 and 13, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules".

[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. Please read Notes 7, 10 and 13 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more detailed disclosures on the Class B units.

[e] On February 14, 2017, we paid TransCanada $22 million representing 30 percent of GTN's total distributable cash flows for the year ended December 31, 2016 less $20 million Please read Notes 7, 10 and 13, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules".

[f] On February 13, 2018, we paid TransCanada $15 million representing 30 percent of GTN's total distributable cash flows for the year ended December 31, 2017 less $20 million Please read Notes 10 and 25, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules".

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.

PNGTS and Iroquois distribute their available cash less any required reserves that are necessary to comply with debt covenants and/or appropriately conduct their respective businesses, as determined and approved by their management committees. While PNGTS' and Iroquois' debt repayments are not funded with cash calls to their owners, PNGTS and Iroquois have historically funded scheduled debt repayments by adjusting available cash for distribution, which effectively reduces the amount of cash available for distributions.

Northern Border's distribution policy requires Northern Border to distribute on a monthly basis, 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.

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 our accounting policies summarized on Notes 2 and 3, Notes to Consolidated Financial Statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules".

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, 2017, our equity investees have regulatory assets amounting to $17 million (2016 – $15 million).

As of December 31, 2017, our equity investees have regulatory liabilities amounting to $28 million (2016 – $27 million).

At December 31, 2017, the Partnership had nil million regulatory assets reported as part of other current assets on the balance sheet representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers continually (2016 – $1 million). As of December 31, 2017, the Partnership had regulatory liabilities of $26 million mostly related to estimated costs associated with future removal of transmission and gathering facilities or allowed to be collected by FERC in depreciation rates (also known as "negative salvage") (2016 – $25 million).

The 2017 Tax Act

On December 22, 2017, the President of the United States signed into law the 2017 Tax Act. This legislation provides for major changes to U.S. corporate federal tax law. As mentioned in the section "Narrative Description of Business-General and Note 2 of the Partnership's consolidated financial statements included in Part IV within Item 15. "Exhibits and Financial Statement Schedules", we are a non-taxable limited partnership, and income taxes owed as a result of our earnings are the responsibility of our partners, therefore no amounts have been recorded in the Partnership's financial statements as a result of the 2017 Tax Act.

Our pipeline systems are regulated by the FERC, which approves the systems' rates on a cost-of-service basis and provides for a recovery of our ultimate taxable owners' income tax expense and related balance sheet accounts as components of the maximum recourse rates that may be charged to customers. As a non-taxable entity, the Partnership does not recognize federal income tax expense nor has it established the related federal deferred income tax assets or liabilities. Income tax related expenses, benefits, assets, and liabilities attributable to regulated operations are the responsibility of the ultimate taxable owners of the Partnership and any adjustment to income tax accounts following the 2017 Tax Act must be evaluated by those owners.

Any changes to the maximum recourse rates charged by our pipeline systems following the 2017 Tax Act will be reflected as those rates are revised through future rate proceedings individually unless superseded through other possible future action by the FERC. The Partnership cannot predict the ultimate impact of the 2017 Tax Act on future revenues of our pipeline systems.

At December 31, 2017, the Partnership considers its assessment of the impact of the 2017 Tax Act to be its best interpretation of available guidance. Should additional guidance on the impact of the 2017 Tax Act on non-taxable partnerships be provided by regulatory, tax and accounting authorities or other sources in the future, the Partnership will review the approach used and adjust as appropriate.

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.

Northern Border

Northern Border's 2013 settlement agreement required Northern Border to file for new rates no later than January 1, 2018. On December 4, 2017, Northern Border filed a rate settlement with FERC which precluded the need to file a general rate case by January 1, 2018. The 2017 Northern Border Settlement, which was approved by FERC on February 23, 2018, provides for tiered rate reductions beginning January 1, 2018, with no change to the underlying rate design. The 2017 Northern Border Settlement does not contain any moratorium and unless superseded by a subsequent rate case or settlement, recourse rates in effect at December 31, 2017, will decrease by 5.0% on January 1, 2018; by an additional 5.50% on April 1, 2018; and by an additional 2.0% beginning January 1, 2020 through December 31, 2023, when Northern Border will be required to establish new rates. This equates to an overall rate reduction of 12.5% by January 1, 2020 from the recourse rates in effect at December 31, 2017.

The 2017 Northern Border Settlement will provide Northern Border with rate stability over the longer term. We do not believe that the rate reduction as described above will have a material impact on the Partnership's results and, therefore, we do not believe the settlement outcome has negatively impacted the underlying value of our investment in Northern Border. The overall long-term market fundamentals of Northern Border continue to be positive due to its strategic footprint. Northern Border remains a key competitive pipeline and continues to operate at full capacity connecting major supply basins with communities in the Midwestern U.S. Accordingly, no impairment has been identified on our investment in Northern Border.

Great Lakes

During the fourth quarter of 2015, we recorded an impairment charge of $199 million on our investment in Great Lakes. The impairment charge was the result of our determination that our investment in Great Lakes' long-term value had been adversely impacted by the changing natural gas flows in its market region and that other strategic alternatives to increase its utilization or revenue were no longer feasible. The impairment charge reduced the difference between the carrying value of our investment in Great Lakes and the underlying equity in the net asset to $260 million, and the difference represented 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.

On October 30, 2017, Great Lakes filed a rate settlement with FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement does not contain a moratorium provision and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022. The 2017 Great Lakes Settlement, which was approved by FERC on February 22, 2018, decreased Great Lakes' maximum transportation rates by 27 percent effective October 1, 2017. At December 31, 2017, the estimation of fair value on our remaining equity investment in Great Lakes was completed and we concluded the fair value of our investment in Great Lakes has not materially changed from 2015.

The assumptions we used in the analysis related to the estimated fair value of our remaining equity investment in Great Lakes included the reduction in Great Lakes' rates effective October 1, 2017. The reduction in rates was offset by expected cash flows from the long-term transportation contract with the TransCanada, other revenue opportunities on the system and the settlement's elimination of the revenue sharing mechanism with its customers. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have been positive, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in an additional future impairment of the carrying value of our investment in Great Lakes.

Our key assumptions 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,
- discount rates and multiples used, and
- changes in other long-term strategic objectives.

As of December 31, 2017, no impairment charge has been recorded related to any of our other equity investments.

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 and multiples;
- 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, 2017 and 2016, 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, 2017.

Long-Lived Assets

We assess our long-lived assets for impairment based on *ASC 360-10-35 Property, Plant, and Equipment – Overall – Subsequent Measurement* when 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, 2017, 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, though future implementation of these rules is uncertain at this time as a result of the recent change in U.S. Presidential Administrations. In any event, several states are also pursuing measures to regulate the emissions of GHGs, including implementation of cap and trade programs or carbon taxes. 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. Please read Part I, Item 1. "Business – Government Regulation" for additional information.

RELATED PARTY TRANSACTIONS

Please read Part III, Item 13. "Certain Relationships and Related Transactions, and Director Independence" and Note 17 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, 2017, the Partnership's interest rate exposure resulted from our floating rate Senior Credit Facility, 2015 Term Loan Facility, GTN's Unsecured Term Facility and Tuscarora's Unsecured Term Facility, under which $435 million, or 18 percent, of our outstanding debt was subject to variability in LIBOR interest rates (2016 – $405 million or 21 percent).

As of December 31, 2017, the variable interest rate exposure related to 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 2.31 percent. If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2017, The Partnership's annual interest expense on its remaining debt with variable interest exposure would increase (decrease) and net income would decrease (increase) by approximately $4 million.

As of December 31, 2017, $15 million, or 6 percent of Northern Border's outstanding debt was at floating rates (2016 – $181 million or 42 percent). If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2017, Northern Border's annual interest expense (decrease) and its net income would decrease (increase) by approximately nil million.

GTN's Unsecured Senior Notes, Northern Border's and Iroquois' Senior Notes, and all of Great Lakes' and PNGTS' 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 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. The Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps maturing July 1, 2018, at a weighted average fixed interest rate of 2.31 percent. At December 31, 2017, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $5 million (on both gross and net basis). At December 31, 2016, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $1 million and a liability of $1 million (on a gross basis) and an asset of nil million (on a net basis). The Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges for the years ended December 31, 2017, 2016 and 2015. The net change in fair value of interest rate derivative instruments recognized in other comprehensive income was a gain of $5 million for the year ended December 31, 2017 (2016 - gain $2 million, 2015 – nil million). In 2017, the net realized loss related to the interest rate swaps was nil, and was included in financial charges and other (2016 – $3 million, 2015 – $2 million).

As discussed in Note 8 within Item 15. Exhibits and Financial Statement Schedules, the Partnership's 2013 Term Loan that was due July 1, 2018, was amended to extend the maturity period through October 2, 2022. As a result of this extension, the Partnership implemented an interest rate hedging strategy after the extension of maturity period and hedged the entire $500 million until its October 2, 2022 maturity using forward starting swaps at an average rate of 3.26 percent.

The Partnership has no master netting agreements, however, its 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 net asset of $5 million as of December 31, 2017 and there would be no effect on the consolidated balance sheet as of December 31, 2016.

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with ASC 815, *Derivatives and Hedging*. PNGTS settled its position with a payment of $20.9 million to counterparties at the time of the refinancing and recorded the realized loss in AOCI as of the termination date. The previously recorded AOCI is currently being amortized against earnings over the life of the PNGTS' 5.90% Senior Secured Notes. At December 31, 2017, our 61.71 percent proportionate share of net unamortized loss on PNGTS included in AOCI was $1 million (2016 – $2 million). For the year ended December 31, 2017, 2016 and 2015, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $0.8 million for each year.

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 cash and cash equivalents and receivables, 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, 2017, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2017, we had a credit risk concentration on one of our customers, Anadarko Energy Services Company, who owed us $4 million. This amount represented approximately 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 facility availability to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation. At December 31, 2017, the Partnership had a Senior Credit Facility of $500 million maturing in 2021 with an outstanding balance on this facility of $185 million. In addition, at December 31, 2017, Northern Border had a committed revolving bank line of $200 million maturing in 2020 and $15 million was drawn. Both the Partnership's Senior Credit Facility and the Northern Border $200 million credit facility have accordion features for additional capacity of $500 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 and are incorporated herein by reference.

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, 2017, 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, 2017 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	57	Chair and Director
Jack F. Stark	67	Independent Director
Malyn K. Malquist	65	Independent Director
Walentin (Val) Mirosh	72	Independent Director
Brandon M. Anderson	45	President, Principal Executive Officer and Director
M. Catharine Davis	53	Director
Joel E. Hunter	51	Director
Janine M. Watson	48	Vice-President and General Manager
Nathaniel A. Brown	41	Controller, Principal Financial Officer
Nancy F. Priemer	59	Vice-President, Taxation
Jon A. Dobson	51	Secretary
William C. Morris	55	Vice-President and 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, Canada and Mexico Natural Gas Pipelines and Energy for TransCanada a position he has held since May 1, 2017. He is accountable for TransCanada's natural gas pipelines and natural gas storage business in Canada and Mexico. Since joining TransCanada in 1994, Mr. Johannson has held several other positions of increasing responsibility, most recently as Executive Vice-President and President, Natural Gas Pipelines for TransCanada from November 2012 to May 2017. 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 served as Chief Financial Officer of Imergy Power Systems, formerly Deeya Energy, an energy storage systems company from December 2013 to July 2016. 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 and Chief Financial Officer of Silicon Valley Bancshares, a diversified financial services provider from April 2004 to May 2007. Mr. Stark also currently serves on the board of directors of ASUS, a wholly-owned subsidiary of Alta Gas Services. From November 2015 to October 2017, he served as a director of TerraForm Power, Inc. and TerraForm Global, Inc., where he also served on the Compensation and Audit Committees of both companies. Through his 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 audit committee experience 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 served on the Board of Directors and Audit Committee of Headwaters Incorporated ("Headwaters"), an NYSE-listed company that provides products, technologies and services in the light building products, heavy construction materials and energy industries, from January 2003 to May 2017, when Headwaters was acquired by Boral, Ltd. 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's principal occupation is Senior Vice President, U.S. Commercial for TransCanada and has main accountability on marketing, business development, rates, commercial operations, regulatory strategy, gas storage and asset optimization of all U.S Natural Gas assets. From July 2016- April 2017, Mr. Anderson was Senior Vice-President and General Manager, U.S. Natural Gas Storage, Midstream for TransCanada. From July 2015 to July 2016, Mr. Anderson was Senior Vice-President and General Manager, U.S. Natural Gas Pipelines for TransCanada. 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, a position she has held since October 2015. 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 Senior Vice-President, Capital Markets for TransCanada, a position he had held since December 2017. In his current position, Mr. Hunter is responsible for Corporate Finance, Corporate Planning, Trading and Financial Risk Management, Cash Management, Investor Relations and Financial Communication, and Treasury. Since joining TransCanada in 1997, Mr. Hunter has held a number of positions of increasing responsibility, most recently as Vice-President, Finance and Treasurer from July 2010 to December 2017 and 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 Tétrault 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 Vice-President, U.S. Gas Pipelines Financial Services of TransCanada, in which position he is responsible for the accounting of TransCanada's U.S. natural gas pipelines. Mr. Brown also served as Manager of accounting for TransCanada's U.S. Pipelines West from November 2009 to May 2014 and as Director of Financial Services for TransCanada's U.S. Pipelines from May 2014 to February 2018. In that capacity, Mr. Brown was responsible for accounting, financial reporting, planning and budgeting. He also provided 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.

Ms. Priemer was appointed Vice-President, Taxation of the General Partner in February 2016. Ms. Priemer's principal occupation is Director, U.S. Natural Gas Pipelines Taxation of TransCanada, a position she has held since July 2009. Prior to this position Ms. Priemer was a Tax Director of an affiliate located in Michigan, a position she held since 1998. Prior to joining TransCanada, Ms. Priemer spent 18 years in both public accounting and industry.

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 Vice President and Treasurer of the General Partner in November 2017. Mr. Morris served as Treasurer of the General Partner since 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 29, 2017.

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 2017.

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 total compensation that are allocable to us vary for each officer or employee performing services on our behalf and are based on the estimated 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.

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

The following table summarizes the salary allocated to, and paid by us in 2017, 2016 and 2015 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

Name and Principal Position	Year	Approximate Percentage of Time Devoted to the Partnership	Total Compensation allocated to the Partnership[(a)] (in US dollars)
Brandon Anderson[(b)]	**2017**	**30%**	**209,135**
President and Principal Executive Officer	2016	30%	199,920
Janine Watson[(c)(d)]	**2017**	**50%**	**170,244**
Vice-President and General Manager	2016	50%	155,782
Nathan A. Brown	**2017**	**35%**	**121,737**
Controller and Principal Financial Officer	2016	35%	112,663
	2015	35%	114,098
Jon A. Dobson	**2017**	**60%**	**253,793**
Secretary	2016	60%	239,226
	2015	50%	208,051
William C. Morris[(d)]	**2017**	**50%**	**163,891**
Vice-President and Treasurer	2016	50%	152,956
	2015	50%	162,881

(a) Amounts presented are the Partnership's allocated portion of compensation paid by TransCanada to the named executive officer for the year indicated based on percentage of time devoted to the Partnership.

(b) Appointed as President and Principal Executive Officer effective January 1, 2016.

(c) Appointed as Vice – President in October 2015.

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

Independent Director Compensation[(a)]

For the year ended December 31, 2017 *(in dollars)*	Cash	Deferred Share Unit Awards[(b)]	Total
Malyn K. Malquist[(c)]	–	177,500	177,500
Jack F. Stark[(d)]	107,500	70,000	177,500
Walentin (Val) Mirosh[(e)]	92,500	70,000	162,500

(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, Brandon Anderson, 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 deferred share units (DSU)s granted during 2017 under the DSU Plan. All of the DSUs granted to Messrs. Malquist, Stark and Mirosh were outstanding at December 31, 2017.

At December 31, 2017, Mr. Malquist, Mr. Stark and Mr. Mirosh held 13,028, 20,397 and 13,778 DSUs, respectively. The fair market value of the DSUs held by Mr. Malquist, Mr. Stark and Mr. Mirosh at December 31, 2017 was $691,766, $1,083,075 and $731,615, 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 740 DSUs, Mr. Stark was credited 1,306 DSUs and Mr. Mirosh was credited 865 DSUs. All DSUs credited during 2017 were outstanding at December 31, 2017.

(c) Chair of the Audit Committee. Mr. Malquist elected to receive DSUs in lieu of the $55,000 annual cash retainer, the $15,000 Audit Committee Chair cash retainer and cash meeting attendance fees in 2017.

(d) Lead Independent Director and Chair of the Conflicts Committee. Cash payments to Mr. Stark include the $55,000 annual cash retainer, $15,000 Conflicts Committee Chair retainer and $22,500 of meeting attendance fees.

(e) Cash payments to Mr. Mirosh include the $55,000 annual cash retainer and $22,500 of meeting attendance fees.

Cash Compensation

In 2017, 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 $125,000 per annum, of which $70,000 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 $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.

Deferred Share Units

The DSU Plan was established in 2007 with the first grant occurring in January 2008. The DSU Plan was amended and restated in its entirety effective as of January 1, 2014. In 2017, as part of the retainer fee, each independent director received an automatic grant of DSUs with a value of $70,000, which was paid quarterly.

At the time of grant, the value of a DSU is equal to the market value of a common unit at the time the independent director is credited with the units. The value of a DSU when redeemed is equivalent to the market value of a common unit at the time the redemption takes place. DSUs cannot be redeemed until the director ceases to be a member of the Board. Directors may redeem DSUs for cash or common units at their option. DSUs redeemed for common units would be purchased by the Partnership in the open market.

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

The following table sets forth information as of February 22, 2018 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	15.8	–	–
TC Pipelines GP, Inc.[(d)] 450-1st Street SW Calgary, Alberta T2P 5H1	5,797,106	8.1	–	–
OppenheimerFunds, Inc.[(e)] Two World Financial Center 225 Liberty Street New York, NY 10281	9,005,426	12.89	–	–
ALPS Advisors, Inc.[(f)] 1290 Broadway, Suite 1100 Denver, CO 80203	4,378,065	6.27	–	–
First Trust Portfolios LP[(g)] 120 East Liberty Drive, Suite 400 Wheaton, Illinois 60187	4,040,374	5.78		
Energy Income Partners, LLC[(h)] 10 Wright Street Westport, Connecticut 06880	5,752,864	8.2		
Malyn K. Malquist[(i)]	14,281	*	–	–
Jack F. Stark[(j)]	21,083	*	–	–
Walentin (Val) Mirosh[(k)]	14,046	*	995	*
Karl R. Johannson[(l)]	–	–	580,758	*
Brandon M. Anderson[(m)]	–	–	120,575	*
M. Catharine Davis[(n)]	–	–	36,533	*
Joel E. Hunter[(o)]	–	–	65,562	*
Nathaniel A. Brown	–	–	–	*
Jon A. Dobson[(p)]	–	–	376	*
William C. Morris[(q)]	–	–	18,254	*
Janine M. Watson[(r)]	–	–	2,547	*
Directors and Executive officers as a Group[(s)] (11 people)	49,410	*	825,600	*

(a) A total of 71,306,396 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, 2018 by OppenheimerFunds, Inc. In this Schedule 13G/A, OppenheimerFunds, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 9,005,426 common units.

(f) Based on a Schedule 13G/A filed with the SEC on February 6, 2018 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 4,378,065 common units.

(g) Based on Schedule 13G filed with the SEC on January 26, 2018 jointly by First Trust Portfolios LP, First Trust Advisors L.P. and The Charger Corporation. In this Schedule 13G, First Trust Portfolios LP, First Trust Advisors L.P. and The Charger Corporation have shared power to vote 4,036,836 common units and to dispose of 4,040,374 common units, and disclaim beneficial ownership of all of said common units.

(h) Based on Schedule 13G/A filed with the SEC on February 14, 2018 by Energy Income Partners, LLC. In this Schedule 13G, Energy Income Partners LLC has shared power to vote and to dispose of the 5,752,864 common units.

(i) Includes 13,281 DSUs and 1,000 common units of the Partnership.

(j) Includes 20,793 DSUs and 290 common units of the Partnership.

(k) Includes 14,046 DSUs and 995 TransCanada common shares.

(l) Includes 549,018 options exercisable within 60 days for TransCanada common shares and 31,740 TransCanada common shares held in his Employee Share Savings Plan account.

(m) Includes 111,030 options exercisable within 60 days for TransCanada common shares, 6,014 TransCanada common shares held directly and 3,531 TransCanada common shares held in his Employee Share Savings Plan accounts.

(n) Includes 35,968 options exercisable within 60 days for TransCanada common shares and 565 TransCanada common shares held in her TransCanada 401(k) and Savings Plan.

(o) Includes 64,621 options exercisable within 60 days for TransCanada common shares, 441 TransCanada common shares held in his Employee Share Savings Plan accounts and 500 TransCanada shares held by Mr. Hunter's parents.

(p) Includes 376 TransCanada common shares held in his TransCanada 401K and Savings Plan account.

(q) Includes 8,724 TransCanada common shares held in his Employee Share Savings Plan account and 9,530 TransCanada common shares held jointly with his spouse.

(r) Includes 793 TransCanada common shares held in her Employee Share Savings Plan account and 1,754 TransCanada common shares held by her spouse.

(s) Includes 48,120 DSUs and 1,290 common units of the Partnership, 7,009 TransCanada common shares held directly, 9,530 TransCanada common shares held with a spouse, 760,637 options exercisable within 60 days for TransCanada common shares, 2,254 TransCanada common shares owned by immediate family members of which beneficial ownership of no common shares is disclaimed, and 45,229 TransCanada common shares held in the TransCanada Employee Share Savings Plan and 941 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 22, 2018, subsidiaries of TransCanada own 17,084,831, or 23.96 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 7, 10, 13 and 14 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 generally make cash distributions of 98 percent to common unitholders, including our general partner with 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 $4 million for the year ended December 31, 2017.

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. At December 31, 2017 and 2016, Great Lakes has an outstanding receivable from this arrangement amounting to $64 million and $27 million, respectively.

Transportation Agreements

Great Lakes

Great Lakes earns significant transportation revenues from TransCanada and its affiliates, some of which are provided at discounted rates, negotiated rates and some at maximum recourse rates. Most recently, during 2017, Great Lakes signed a significant long-term contract with TransCanada that would allow TransCanada the ability to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system from the Manitoba/U.S. border to the U.S. border near Dawn Ontario beginning November 1, 2017. (Please see Part 1, Item 1. Business – "Recent Business Developments" for further details).

For the year ended December 31, 2017, Great Lakes earned 57 percent of its transportation revenues from TransCanada and its affiliates (2016 – 68 percent; 2015 – 71 percent). Additionally, Great Lakes earned approximately one percent of its total revenues as affiliated rental revenue in 2017 (2016 – 1 percent and 2015 – 1 percent).

At December 31, 2017, $20 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2016 – $19 million).

In 2017, Great Lakes operated under a FERC approved 2013 rate settlement that includes a revenue sharing mechanism that requires Great Lakes to share with its customers certain percentages of any qualifying revenues earned above certain ROEs. A refund of $7 million was paid to shippers in 2017 relating to the year ended December 31, 2016, of which approximately 86 percent was made to affiliates of Great Lakes. For the year ended December 31, 2017, Great Lakes has recorded an estimated revenue sharing provision amounting to $40 million and Great Lakes expects that a significant percentage of the 2017 revenue sharing refund will be to its affiliates.

Under the terms of the 2017 Great Lakes Settlement, beginning 2018, the revenue sharing was eliminated. Additionally, effective October 1, 2017, Great Lakes still charged customers rates in effect prior to the 2017 Great Lakes Settlement but only recognized revenue up to the amount of the new rates in the 2017 Great Lakes Settlement. The difference between these two amounts was recognized as a provision for rate refund (liability) on Great Lakes' balance sheet amounting to $8 million. Great Lakes expects that a significant percentage of the provision for rate refund will be to its affiliates as well. See Note 5 on Part IV within Item 15. "Exhibits and Financial Statement Schedules").

PNGTS

In connection with the PXP project, PNGTS entered into a precedent agreement with TransCanada for capacity on its mainline system. Please see Part 1, Item 1. Business – "Recent Business Developments" for further details.

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 7 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. 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, 2017, 2016 and 2015 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2017 and 2016 are summarized in Note 17 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)*	**2017**	2016	2015
Audit Fees[(a)(b)(c)]	**861**	1,071	1,067
Audit Related Fees	**–**	–	–
Tax Fees[(d)]	**–**	–	–
All Other Fees	**–**	–	–
Total	**861**	1,071	1,067

(a) $200 thousand of the 2017 audit fees relate to ATM equity financing (2016 – $320 thousand and 2015 – $200 thousand).

(b) $65 thousand of the 2017 audit fees relate to issuance of senior unsecured notes (2016 – none, 2015 – $150 thousand)

(c) $26 thousand of 2015 audit fees related to advisory services for Class B issuance.

(d) The Partnership did not engage its external auditors for any tax or other services in 2017, 2016 or 2015.

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.

The Audit Committee has a policy to pre-approve the engagement fees and terms of all audit, audit-related, tax and other non-audit services provided to the Partnership by the independent registered public accounting firm. All of the fees in the table above were approved in accordance with this policy. As part of the pre-approval process, the Audit Committee also evaluates all non-audit services to be provided by the independent registered public accounting firm to ensure the provision of the non-audit services is compatible with maintaining the independence of the independent registered public accounting firm under applicable federal securities laws and stock exchange rules. Pre-approval is detailed as to the particular service or category of services and is subject to a specific budget or fee structure. The Audit Committee may delegate to one of its members the authority to pre-approve the engagement of the independent registered public accounting firm for permitted non-audit services, provided that such member is required to present the pre-approval of any permitted non-audit service to the full Audit Committee at its next meeting following any such pre-approval.

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).]
2.3*	Agreement for Purchase and Sale of Partnership Interest in Iroquois Gas Transmission System, L.P. by and between TCPL Northeast Ltd. and TransCanada Iroquois Ltd., as Sellers and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed May 3, 2017).
2.3.1*	First Amendment to Purchase and Sale Agreement by and between TCPL Northeast Ltd. and TransCanada Iroquois Ltd., as Sellers and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 31, 2017 (Incorporated by reference from Exhibit 2.1.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
2.4*	Option Agreement Relating to Partnership Interest in Iroquois Gas Transmission System, L.P. by and between TransCanada Iroquois Ltd. and TC Pipelines Intermediate Limited Partnership as dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.2 to TC PipeLines, LP's Form 8-K filed May 3, 2017).
2.5*	Agreement for Purchase and Sale of Partnership Interest in Portland Natural Gas Transmission System, by and between TCPL Portland Inc., as Seller and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.3 to TC PipeLines, LP's Form 8-K filed May 3, 2017).
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).
3.1.1*	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated December 13, 2017 (incorporated by reference from Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed December 15, 2017).

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).
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).
4.6*	Third Supplemental Indenture, dated as of May 25, 2017, relating to the issuance of $500,000,000 aggregate principal amount of 3.900% Senior Notes due 2027 (Incorporated by reference from Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed May 25, 2017).
4.7*	Portland Natural Gas Transmission System Senior Secured Note Purchase Agreement dated as of April 10, 2003 (Incorporated by reference from Exhibit 4.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
4.8*	Iroquois Gas Transmission, L.P. Senior Note Purchase Agreement dated as of May 13, 2009 (Incorporated by reference from Exhibit 4.2 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
4.9*	Iroquois Gas Transmission, L.P. Senior Note Purchase Agreement dated as of April 27, 2010(Incorporated by reference from Exhibit 4.3 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
4.10*	Indenture dated as of May 30, 2000, between Iroquois Gas Transmission System, L.P. and The Chase Manhattan Bank (Incorporated by reference from Exhibit 4.4 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
4.10.1*	Second Supplemental Indenture dated as of August 13, 2002, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank (formerly known as The Chase Manhattan Bank) (Incorporated by reference from Exhibit 4.4.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
4.11*	Credit Agreement dated as of June 26, 2008, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent (Incorporated by reference from Exhibit 4.5 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
4.11.1*	Amendment No. 1 to Credit Agreement dated as of June 25, 2009, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent for the lenders (Incorporated by reference from Exhibit 4.5.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.1*	Operating Agreement by and between Portland Natural Gas Transmission System and PNGTS Operating Co., LLC dated October 2, 1996 (Incorporated by reference from Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.2*	Amended and Restated Operating Agreement by and between PNGTS Operating Co., LLC and 9207670 Delaware Inc. dated January 1, 2012 (Incorporated by reference from Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).

10.3*	Amended and Restated Operating Agreement by and between PNGTS Operating Co., LLC and 1120436 Alberta Ltd., Inc. dated January 1, 2012 (Incorporated by reference from Exhibit 10.3 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4*	Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated March 1, 1996 (Incorporated by reference from Exhibit 10.4 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.1*	First Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated May 23, 1996 (Incorporated by reference from Exhibit 10.4.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.2*	Second Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated October 23, 1996 (Incorporated by reference from Exhibit 10.4.2 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.3*	Third Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated March 17, 1998 (Incorporated by reference from Exhibit 10.4.3 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.4*	Fourth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated March 31, 1998 (Incorporated by reference from Exhibit 10.4.4 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.5*	Fifth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated September 30, 1998 (Incorporated by reference from Exhibit 10.4.5 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.6*	Sixth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated June 4, 1999 (Incorporated by reference from Exhibit 10.4.6 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.7*	Seventh Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated June 28, 2001 (Incorporated by reference from Exhibit 10.4.7 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.8*	Eighth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated September 29, 2003 (Incorporated by reference from Exhibit 10.4.8 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.9*	Ninth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated December 3, 2003 (Incorporated by reference from Exhibit 10.4.9 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.10*	Tenth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated February 11, 2005 (Incorporated by reference from Exhibit 10.4.10 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.11*	Eleventh Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated March 17, 2008(Incorporated by reference from Exhibit 10.4.11 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.4.12*	Twelfth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated January 1, 2016(Incorporated by reference from Exhibit 10.4.12 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).

10.4.13*	Thirteenth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated June 1, 2017 (Incorporated by reference from Exhibit 10.4.13 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.5*	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).
10.6*	Third Amended and Restated Agreement of Limited Partnership Agreement of Iroquois Gas Transmission, L.P. (Incorporated by reference from Exhibit 10.6 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.7*	Transportation Service Agreement FT18966 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, effective August 4, 2017 (Incorporated by reference from Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed November 6, 2017).
10.8*	Second Amendment to TC PipeLines LP's July 1, 2013 Term Loan Agreement, dated September 29, 2017 (Incorporated by reference from Exhibit 99.1 to TC PipeLines, LP's Form 8-K filed October 3, 2017).
10.9*	Amendment No. 1 to TC PipeLines LP's September 30, 2015 Term Loan Agreement, dated September 29, 2017 (Incorporated by reference from Exhibit 99.2 to TC PipeLines, LP's Form 8-K filed October 3, 2017).
10.10*	First Amendment to TC PipeLines, LP's Third Amended and Restated Revolving Credit Agreement, dated September 29, 2017 (Incorporated by reference from Exhibit 99.3 to TC PipeLines, LP's Form 8-K filed October 3, 2017).
10.11*	Credit Agreement dated as of June 26, 2008, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent (Incorporated by reference from Exhibit 4.5 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.11.1*	Amendment No. 1 to Credit Agreement dated as of June 25, 2009, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent for the lenders (Incorporated by reference from Exhibit 4.5.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017).
10.12*	PNGTS' precedent agreement and corresponding financial assurances agreement with TransCanada (Incorporated by reference from Exhibits 10.1 and 10.2 to TC PipeLines, LP's Form 8-K filed December 15, 2017).
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 Executive 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 FT18577 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date January 09, 2017. (Incorporated by reference to Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed on May 4, 2017).
99.2*	Transportation Service Agreement FT18659 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 01, 2017. (Incorporated by reference to Exhibit 99.2 to TC PipeLines, LP's Form 10-Q filed on May 4, 2017).
99.3*	Transportation Term Sheet between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited (Incorporated by reference to Exhibit 99.3 to TC PipeLines, LP's Form 10-Q filed on May 4, 2017).
99.4*	Transportation Service Agreement FT-2010-001 between Portland Natural Gas Transmission System and TransCanada Energy Ltd., effective date July 01, 2010. (Incorporated by reference from Exhibit 99.2 TC PipeLines, LP's Form 10-Q filed August 3, 2017).
99.5*	Transportation Service Agreement FT18659 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 1, 2017. (Incorporated by reference from Exhibit 99.3 TC PipeLines, LP's Form 10-Q filed August 3, 2017).
99.6*	Transportation Service Agreement FT18759 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 26, 2017. (Incorporated by reference from Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed November 6, 2017).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Indicates exhibits incorporated by reference.

\# 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 2018.

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, 2018
/s/ Brandon Anderson Brandon Anderson	President and Principal Executive Officer	February 26, 2018
/s/ Nathaniel A. Brown Nathaniel A. Brown	Controller and Principal Financial Officer	February 26, 2018
/s/ M. Catharine Davis M. Catharine Davis	Director	February 26, 2018
/s/ Joel E. Hunter Joel E. Hunter	Director	February 26, 2018
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 26, 2018
/s/ Jack F. Stark Jack F. Stark	Director	February 26, 2018
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 26, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of TC PipeLines, LP (a Delaware limited partnership) and subsidiaries (the Partnership) as of December 31, 2017 and 2016, the related consolidated 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, 2017, and the related notes (collectively, the consolidated financial statements). We also have audited the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinion

The Partnership's management 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 the Partnership's consolidated financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control Over Financial Reporting

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 company'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.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2011.

Houston, Texas
February 26, 2018

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	**2017**	2016[a]
ASSETS		
Current Assets		
Cash and cash equivalents	**33**	64
Accounts receivable and other (Note 20)	**42**	47
Inventories	**8**	7
Other	**7**	7
	90	125
Equity investments (Note 5)	**1,213**	918
Plant, property and equipment, net (Note 6)	**2,123**	2,180
Goodwill	**130**	130
Other assets	**3**	1
	3,559	3,354
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**31**	29
Accounts payable to affiliates (Note 17)	**5**	8
Accrued interest	**12**	10
Distributions payable	**1**	3
Current portion of long-term debt (Note 8)	**51**	52
	100	102
Long-term debt (Note 8)	**2,352**	1,859
Deferred state income taxes (Note 24)	**10**	10
Other liabilities (Note 9)	**29**	28
	2,491	1,999
Common units subject to rescission (Note 10)	**–**	83
Partners' Equity (Note 10)		
Common units	**824**	1,002
Class B units	**110**	117
General partner	**24**	27
Accumulated other comprehensive income (loss) (AOCI) (Note 11)	**5**	(2)
Controlling interests	**963**	1,144
Non-controlling interest	**105**	97
Equity of former parent of PNGTS	**–**	31
	1,068	1,272
	3,559	3,354

Contingencies (Note 22)
Variable Interest Entities (Note 23)
Subsequent Events (Note 25)

(a) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

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)	**2017**	2016[a]	2015[a]
Transmission revenues	**422**	426	417
Equity earnings (Note 5)	**124**	97	97
Impairment of equity-method investment (Note 5)	**–**	–	(199)
Operation and maintenance expenses	**(67)**	(58)	(61)
Property taxes	**(28)**	(27)	(27)
General and administrative	**(8)**	(7)	(9)
Depreciation	**(97)**	(96)	(95)
Financial charges and other (Note 12)	**(82)**	(71)	(63)
Net income before taxes	**264**	264	60
Income taxes (Note 24)	**(1)**	(1)	(2)
Net Income	**263**	263	58
Net income attributable to non-controlling interests	**11**	15	21
Net income attributable to controlling interests	**252**	248	37
Net income attributable to controlling interest allocation (Note 13)			
Common units	**219**	211	(2)
General Partner	**16**	11	3
TransCanada and its subsidiaries	**17**	26	36
	252	248	37
Net income per common unit (Note 13) – basic and diluted[b]	**$3.16**	$3.21	$(0.03)
Weighted average common units outstanding *(millions)* – basic and diluted	**69.2**	65.7	63.9
Common units outstanding, end of year *(millions)*	**70.6**	67.4	64.3

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2017**	2016[(a)]	2015[(a)]
Net income	**263**	263	58
Other comprehensive income			
Change in fair value of cash flow hedges (Notes 11 and 19)	**5**	3	–
Reclassification to net income of gains and losses on cash flow hedges (Note 11)	**–**	(2)	–
Amortization of realized loss on derivative instrument (Notes 11 and 19)	**1**	1	1
Other comprehensive income on equity investments (Note 11)	**1**	–	–
Comprehensive income	**270**	265	59
Comprehensive income attributable to non-controlling interests	**11**	16	21
Comprehensive income attributable to controlling interests	**259**	249	38

(a) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

(b) Net income per common unit prior to recast (Refer to Note 2).

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)	**2017**	2016[a]	2015[a]
Cash Generated From Operations			
Net income	**263**	263	58
Depreciation	**97**	96	95
Impairment of equity-method investment (Note 5)	**–**	–	199
Amortization of debt issue costs reported as interest expense (Note 12)	**2**	2	1
Amortization of realized loss on derivative instrument (Note 19)	**1**	1	1
Accrual of costs related to acquisition of 49.9% interest in PNGTS (Note 7)	**–**	–	2
Equity earnings from equity investments (Note 5)	**(124)**	(97)	(97)
Distributions received from operating activities of equity investments (Note 5)	**140**	153	119
Provision for deferred state income taxes (Note 24)	**–**	–	4
Provision for rate refund-PNGTS (Note 2)	**–**	–	(101)
Equity allowance for funds used during construction	**(1)**	–	(1)
Change in operating working capital (Note 15)	**(2)**	(1)	(20)
	376	417	260
Investing Activities			
Investment in Northern Border (Note 5)	**(83)**	–	–
Investment in Great Lakes (Note 5)	**(9)**	(9)	(9)
Distribution received from Iroquois as return of investment (Note 5)	**5**	–	–
Acquisition of a 49.34 percent in Iroquois and an additional 11.81 percent in PNGTS (Note 7)	**(646)**	–	–
Acquisition of 49.9 percent interest in PNGTS (Note 7)	**–**	(193)	–
Acquisition of the remaining 30 percent interest in GTN (Note 7)	**–**	–	(264)
Capital expenditures	**(29)**	(29)	(54)
Other	**1**	1	1
	(761)	(230)	(326)
Financing Activities			
Distributions paid (Note 14)	**(284)**	(250)	(228)
Distributions paid to Class B units (Note 10 and 14)	**(22)**	(12)	–
Distributions paid to non-controlling interests	**(5)**	(12)	(21)
Distributions paid to former parent of PNGTS	**(1)**	(9)	(19)
Common unit issuance, net (Note 10)	**176**	84	44
Common unit issuance subject to rescission, net (Note 10)	**–**	83	–
Equity contribution by the General Partner (Note 7)	**–**	–	2
Long-term debt issued, net of discount (Note 8)	**802**	209	618
Long-term debt repaid (Note 8)	**(310)**	(270)	(425)
Debt issuance costs	**(2)**	(1)	(3)
	354	(178)	(32)
Increase/(decrease) in cash and cash equivalents	**(31)**	9	(98)
Cash and cash equivalents, beginning of year	**64**	55	153
Cash and cash equivalents, end of year	**33**	64	55
Interest payments paid	**79**	66	59
State income taxes paid	**2**	2	2
Supplemental information about non-cash investing and financing activities			
Accrued capital expenditures	**9**	–	10
Issuance of Class B units to TransCanada (Note 10)	**–**	–	95

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 7).

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

TC PIPELINES, LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

(millions of units) *(millions of dollars)*	Limited Partners				General Partner	Accumulated Other Comprehensive Income (Loss)[a][c]	Non-Controlling Interest[d]	PNGTS[c][d]	Total Equity[d]
	Common Units		Class B Units						
Partners' Equity at December 31, 2014[d]	63.6	1,325	–	–	29	(5)	323	146	1,818
Issuance of Class B Units (Note 7 and 10)	–	–	1.9	95	–	–	–	–	95
Net income (loss)[d]	–	(2)	–	12	3	–	21	24	58
Other Comprehensive Loss, net[d]	–	–	–	–	–	1	–		1
ATM Equity Issuance, net (Note 10)	0.7	43	–	–	1	–	–	–	44
Acquisition of the remaining interest in GTN (Note 7)	–	(124)	–	–	(3)	–	(232)	–	(359)
Equity Contribution (Note 7)	–	–	–	–	2	–	–	–	2
Distributions[d]	–	(221)	–	–	(7)	–	(21)	(19)	(268)
Partners' Equity at December 31, 2015[d]	64.3	1,021	1.9	107	25	(4)	91	151	1,391
Net income[d]	–	211	–	22	11	–	15	4	263
Other Comprehensive Income, net[d]	–	–	–	–	–	2	1	–	3
Common unit issuance subject to rescission, net[b] (Note 10)	1.6	81	–	–	2	–	–		83
Reclassification of common unit issuance subject to rescission, net[b] (Note 10)	–	(81)	–	–	(2)	–	–	–	(83)
ATM Equity Issuance, net (Note 10)	1.5	82	–	–	2	–	–	–	84
Acquisition of 49.9 percent interest in PNGTS (Note 7)	–	(72)	–	–	(1)	–	–		(73)
Distributions[d]	–	(240)	–	(12)	(10)	–	(10)	(4)	(276)
Former parent carrying amount of PNGTS[d]	–	–	–	–	–	–	–	(120)	(120)
Partners' Equity at December 31, 2016[d]	67.4	1,002	1.9	117	27	(2)	97	31	1,272
Net income	–	219	–	15	16	–	11	2	263
Other comprehensive income	–	–	–	–	–	7	–	–	7
ATM equity issuances, net (Note 10)	3.2	173	–	–	3	–	–	–	176
Reclassification of common units no longer subject to rescission (Note 10)	–	81	–	–	2	–	–	–	83
Acquisition of interests in PNGTS and Iroquois (Note 7)	–	(383)	–	–	(8)	–	–	(32)	(423)
Distributions	–	(268)	–	(22)	(16)	–	(3)	(1)	(310)

Partners' Equity at December 31, 2017[d]	**70.6**	**824**	**1.9**	**110**	**24**	**5**	**105**	**–**	**1,068**

[a] Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $2 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] These units are treated as outstanding for financial reporting purposes.

[c] Equity of Former Parent of PNGTS.

[d] Recast to consolidate PNGTS (Refer to Notes 2 and 7).

The accompanying notes are an integral part of these 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 interests in the following natural gas pipeline systems through three intermediate limited partnerships (ILPs), TC GL Intermediate Limited Partnership, TC PipeLines Intermediate Limited Partnership and TC Tuscarora Intermediate Limited Partnership:

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
Bison Pipeline LLC (Bison)	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can transport natural gas from the Powder River Basin to Midwest markets.	100 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
Northern Border Pipeline Company (Northern Border)	1,412 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 Bakken, 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
Portland Natural Gas Transmission System (PNGTS)	295 miles	Connects with the TQM at the Canadian border to deliver natural gas to customers in the U.S. northeast. Northern New England Investment Company, Inc. owns the remaining 38.29 percent of PNGTS. The 295-mile pipeline includes a 107 miles of jointly owned pipeline facilities (the Joint Facilities) with MNE. The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32% of the undivided ownership interest based on contractually agreed upon percentages. The Joint Facilities are maintained and operated by a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.	61.71 percent[(a)]
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
Iroquois Gas Transmission System, L.P (Iroquois)	416 miles	Extends from the TransCanada Mainline system near Waddington, New York to deliver natural gas to customers in the U.S. northeast. The remaining 50.66 percent is owned by TransCanada (0.66 percent), Dominion Midstream (25.93 percent) and Dominion Resources (24.07 percent). Iroquois is maintained and operated by a subsidiary of Iroquois.	49.34 percent[(b)]

(a) On June 1, 2017, the Partnership acquired an additional 11.81 percent from TransCanada resulting in 61.71 percent ownership in PNGTS. (Refer to Note 7).

(b) Effective June 1, 2017 (Refer to Note 7).

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 to the Partnership and is reimbursed for its costs and expenses. The General Partner owns 5,797,106 of our common units, 100 percent of our IDRs and an effective two percent general partner interest in the Partnership at December 31, 2017. TransCanada also indirectly holds an additional 11,287,725 common units, for total ownership of 24.2 percent of our outstanding common units and 100 percent of our Class B units at December 31, 2017 (Refer to Note 10).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated 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, 2017 and 2016 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2017, 2016 and 2015.

(a) Basis of Presentation

The Partnership consolidates variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. 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 entities over which it is able to exercise significant influence.

Acquisitions by the Partnership from TransCanada are considered common control transactions. When businesses that will be consolidated are acquired from TransCanada by the Partnership, the historical financial statements are required to be recast, except net income (loss) per common unit, to include the acquired entities for all periods presented.

When the Partnership acquires an asset or an investment from TransCanada, which will be accounted for by the equity method, the financial information is not required to be recast and the transaction is accounted for prospectively from the date of the acquisition.

On June 1, 2017, the Partnership acquired from a subsidiary of TransCanada an additional 11.81 percent interest in PNGTS, resulting in the Partnership owning 61.71 percent in PNGTS (Refer to Note 7). As a result of the Partnership owning 61.71 percent of PNGTS, the Partnership's historical financial information was recast, except net income (loss) per common unit, to consolidate PNGTS for all the periods presented in these consolidated financial statements. Additionally, this acquisition was accounted for as transaction between entities under common control, similar to pooling of interests, whereby the assets and liabilities of PNGTS were recorded at TransCanada's carrying value.

Also, on June 1, 2017, the Partnership acquired from subsidiaries of TransCanada a 49.34 percent interest in Iroquois (Refer to Note 7). Accordingly, this transaction was accounted for as a transaction between entities under common control, similar to pooling of interest, whereby the equity investment in Iroquois was recorded at TransCanada's carrying value and was accounted for prospectively.

On January 1, 2016, the Partnership acquired a 49.9 percent interest in PNGTS (2016 PNGTS Acquisition) from a subsidiary of TransCanada. The 2016 PNGTS Acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the equity investment in PNGTS was recorded at TransCanada's carrying value and the total excess purchase price paid was recorded as a reduction in Partners' Equity. Accordingly, the equity investment on PNGTS is being eliminated as a result of consolidating PNGTS for all periods presented. Refer to Note 7 for additional disclosure regarding the PNGTS Acquisition.

On April 1, 2015, the Partnership acquired the remaining 30 percent interest in GTN from a subsidiary of TransCanada. This acquisition resulted in being wholly-owned by the Partnership. 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 acquisitions of this already-consolidated entity was 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 7 for additional disclosures regarding these acquisitions.

(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) 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 pipelines' tariff.

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

(f) Inventories

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

(g) 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.

The Partnership's subsidiaries capitalize a carrying cost on funds invested in the construction of long lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC), calculated based the average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of plant, property and equipment on the balance sheets. Amounts included in construction work in progress are not amortized until transferred into service.

(h) 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.

(i) 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.

(j) Partners' Equity

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

(k) 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, 2017, the Partnership has not recognized any transmission revenue that is subject to possible refund.

For the years ended December 31, 2014 and in January 2015, as required by FERC, PNGTS was charging customers rates applied for in its 2008 and 2010 rate cases. Due to the uncertainty in the outcome of its two outstanding rate cases, PNGTS was only recognizing revenue up to the amount of the interim FERC approved rates. The difference between these amounts was recognized as a provision (liability) for rate refund in the consolidated balance sheet. On February 19, 2015, FERC approved PNGTS' final rates and PNGTS was required to refund the customers within sixty days of the issuance of the final rates, including interest at the quarterly average prime interest rate as prescribed by FERC. Total refunds accumulated to $114.3 million, including $8.0 million of interest, and were paid to customers on April 15, 2015.

(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. Debt issuances costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount and premiums. The amortization of debt issuance costs is reported as interest expense.

(m) Income Taxes

Federal and certain state income taxes are the responsibility of the partners and are not reflected in these consolidated financial statements. 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.

In instances where the Partnership is subject to state income taxes, the asset – liability method is used to account for taxes. This method requires the recognition of deferred tax assets and liabilities for future tax consequences attributable to the differences between the financial statement carrying amount of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are classified as non-current on our balance sheet.

(n) 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.

At December 31, 2017 and 2016, we had $130 million of goodwill recorded on our consolidated balance sheet related to the North Baja ($48 million) and Tuscarora ($82 million) acquisitions. No impairment of goodwill existed at December 31, 2017.

The Partnership accounts for business acquisitions between itself and TransCanada, also known as "dropdowns", 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 (loss) 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.

(o) 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.

(p) 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.

(q) 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 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, 2017 and 2016.

(r) 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, 2017, the Partnership had regulatory assets amounting to nil reported as part of other current assets in the balance sheet representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers continually (2016 – $1 million). Regulatory liabilities are included in other long-term liabilities (refer to Note 9). AFUDC is capitalized and included in plant, property and equipment.

NOTE 3 ACCOUNTING PRONOUNCEMENTS

Changes in Accounting Policies effective January 1, 2017

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The new guidance specifies that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance was effective January 1, 2017, was applied prospectively and did not have a material impact on the Partnership's consolidated balance sheet.

Equity method and joint ventures

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies for equity method accounting. The new guidance is effective January 1, 2017 and was applied prospectively. The application of this guidance did not have a material impact on the Partnership's consolidated financial statements.

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to interests held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a variable interest entity (VIE), it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The guidance was effective January 1, 2017, was applied retrospectively and did not result in any change to our consolidation conclusions.

Future accounting changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. The Partnership will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. The Partnership will adopt the guidance using the modified retrospective approach with the cumulative-effect of the adjustment recognized at the date of adoption, subject to allowable and elected practical expedients.

The Partnership has identified all existing customer contracts that are within the scope of the new guidance. The Partnership has completed its analysis and has not identified any material differences in the amount and timing of revenue recognition as a result of implementing the new guidance. The Partnership will not require a cumulative-effect adjustment to opening partners' equity on January 1, 2018.

Although consolidated revenues will not be materially impacted by the new guidance, the Partnership will be required to add significant disclosures based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating when and how revenue is recognized and information related to contract assets and deferred revenues. In addition, the new guidance requires that the Partnership's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenue and cash flows generated from contracts with customers. The Partnership has developed draft disclosures required in the first quarter 2018 with a particular focus on the scope of contracts subject to disclosure of future revenues from remaining performance obligations. The Partnership has addressed system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease requiring the customer to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset in order for the arrangement to qualify as a lease. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than

12 months. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

The new guidance is effective on January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership is continuing to identify and analyze existing lease agreements to determine the effect of adoption of the new guidance on its consolidated financial statements. The Partnership is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance. The Partnership continues to monitor and analyze additional guidance and clarification provided by FASB.

Goodwill Impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted.

Hedge Accounting

In August 2017, the FASB issued new guidance on hedge accounting, making more financial and nonfinancial hedging strategies eligible for hedge accounting. The new guidance amends the presentation requirements relating to the change in fair value of a derivative and additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019 with early adoption permitted. The Partnership has elected to apply this guidance effective January 1, 2018. The Partnership has completed its analysis and does not expect the application of this guidance to have a material impact on its consolidated financial statements.

NOTE 4 THE 2017 TAX ACT

On December 22, 2017, the President of the United States signed into law the 2017 Tax Act. This legislation provides for major changes to U.S. corporate federal tax law. As mentioned in Note 2, we are a non-taxable limited partnership, and income taxes owed as a result of our earnings are the responsibility of our partners, therefore no amounts have been recorded in the Partnership's financial statements as a result of the 2017 Tax Act.

Our pipeline systems are regulated by the FERC, which approves the systems' rates on a cost-of-service basis and provides for a recovery of our ultimate taxable owners' income tax expense and related balance sheet accounts as components of the maximum recourse rates that may be charged to customers. As a non-taxable entity, the Partnership does not recognize federal income tax expense nor has it established the related federal deferred income tax assets or liabilities. Income tax related expenses, benefits, assets, and liabilities attributable to regulated operations are the responsibility of the ultimate taxable owners of the Partnership and any adjustment to income tax accounts following the 2017 Tax Act must be evaluated by those owners.

Any changes to the maximum recourse rates charged by our pipeline systems following the 2017 Tax Act will be reflected as those rates are revised through future rate proceedings individually unless superseded through other possible future action by the FERC. The Partnership cannot predict the ultimate impact of the 2017 Tax Act on future revenues of our pipeline systems.

At December 31, 2017, the Partnership considers its assessment of the impact of the 2017 Tax Act to be its best interpretation of available guidance. Should additional guidance on the impact of the 2017 Tax Act on non-taxable partnerships be provided by regulatory, tax and accounting authorities or other sources in the future, the Partnership will review the approach used and adjust as appropriate.

NOTE 5 EQUITY INVESTMENTS

The Partnership has equity interests in Northern Border, Great Lakes and, effective June 1, 2017, Iroquois. The pipeline systems owned by these entities are regulated by FERC. The pipeline systems of Northern Border and Great Lakes are operated by subsidiaries of TransCanada. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Partnership uses the equity method of accounting for its interests in its equity investees. The Partnership's equity investments are held through our ILPs that are considered to be variable interest entities (VIEs). Refer to Note 23, Variable Interest Entities.

(millions of dollars)	Ownership Interest at December 31, 2017	Equity Earnings[b] Year ended December 31 2017	2016[c]	2015	Equity Investments December 31 2017	2016[c]
Northern Border[a]	50.00%	**67**	69	66	**512**	444
Great Lakes	46.45%	**31**	28	31	**479**	474
Iroquois	49.34%	**26**	–	–	**222**	–
		124	97	97	**1,213**	918

(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 acquisition of an additional 20 percent 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. Accordingly, no impairment charge was recorded by the Partnership on its equity investees for all the periods presented here except the $199 million impairment recognized in 2015 on our investment in Great Lakes as discussed below.

(c) Recast to eliminate equity earnings from PNGTS and consolidate PNGTS (Refer to Notes 2 and 7).

Distributions from Equity Investments

As a result of adoption of FASB ASU 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*, the Partnership changed its method of accounting for the classification of distributions received from equity investments from cumulative earnings approach to nature of distributions approach effective January 1, 2014, as it is more representative of the nature of the underlying activities of the investees that generated the distributions. As a result, distributions received from equity method investees in 2015, amounting to $25 million, have been reclassified from investing activities to cash generated from operations in the consolidated statement of cash flows.

Distributions received from equity investments for the year ended December 31, 2017 were $145 million (2016 – $153 million; 2015 – $119 million) of which $5 million (2016 and 2015 – none) was considered a return of capital and is included in Investing activities in the Partnership's consolidated statement of cash flows. The return of capital was related to our investment in Iroquois (see further discussion below).

Northern Border

The Partnership, through its interest in TC PipeLines Intermediate Limited 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.

On September 1, 2017, the Partnership made an equity contribution to Northern Border amounting to $83 million. This amount represents the Partnership's 50 percent share of a $166 million capital contribution request from Northern Border to reduce the outstanding balance of its revolving credit facility to increase its available borrowing capacity.

The Partnership recorded no undistributed earnings from Northern Border for the years ended December 31, 2017, 2016 and 2015. At December 31, 2017 the Partnership had a $115 million (December 31, 2016 – $116 million) difference between the carrying value of Northern Border and the underlying equity in the net assets primarily resulting from the recognition and inclusion of goodwill in the Partnership's investment in Northern Border relating to the Partnership's April 2006 acquisition of an additional 20 percent general partnership interest in Northern Border.

Northern Border's 2013 settlement agreement required Northern Border to file for new rates no later than January 1, 2018. On December 4, 2017, Northern Border filed a rate settlement with FERC which precluded the need to file a general rate case by January 1, 2018. The 2017 Northern Border Settlement, which was approved by FERC on February 23, 2018, provides for tiered rate reductions beginning January 1, 2018, with no change to the underlying rate design. The 2017 Northern Border Settlement does not contain a moratorium provision and, unless superseded by a subsequent rate case or settlement, recourse rates in effect at December 31, 2017, will decrease by 5.0% on January 1, 2018; by an additional 5.50% on April 1, 2018; and by an additional 2.0% beginning January 1, 2020 through December 31, 2023, when Northern Border will be required to establish new rates. This equates to an overall rate reduction of 12.5% by January 1, 2020 from the recourse rates in effect at December 31, 2017.

The 2017 Northern Border Settlement will provide Northern Border with rate stability over the longer term. We do not believe that the rate reduction as described above will have a material impact on the Partnership's results and, therefore, we do not believe the settlement outcome has negatively impacted the underlying value of our investment in Northern Border. The overall long-term market fundamentals of Northern Border continue to be positive due to its strategic footprint. Northern Border remains a key competitive pipeline and continues to operate at full capacity connecting major supply basins with communities in the Midwestern U.S. Accordingly, no impairment has been identified in our investment in Northern Border.

The summarized financial information provided to us by Northern Border is as follows:

December 31 (millions of dollars)	**2017**	2016
Assets		
Cash and cash equivalents	**14**	14
Other current assets	**36**	36
Plant, property and equipment, net	**1,063**	1,089
Other assets	**14**	14
	1,127	1,153
Liabilities and Partners' Equity		
Current liabilities	**38**	38
Deferred credits and other	**31**	28
Long-term debt, net[(a)]	**264**	430
Partners' equity		
Partners' capital	**795**	659
Accumulated other comprehensive loss	**(1)**	(2)
	1,127	1,153

Year ended December 31 (millions of dollars)	**2017**	2016	2015
Transmission revenues	**291**	292	286
Operating expenses	**(78)**	(72)	(70)
Depreciation	**(59)**	(59)	(60)
Financial charges and other	**(18)**	(21)	(22)
Net income	**136**	140	134

(a) No current maturities as of December 31, 2017 or 2016.

Great Lakes

The Partnership, through its interest in TC GL Intermediate Limited 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.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2017, 2016, and 2015.

The Partnership made equity contributions to Great Lakes of $4 million and $5 million in the first and fourth quarter of 2017, 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.

During the fourth quarter of 2015, we recorded an impairment charge of $199 million on our investment in Great Lakes. The impairment charge was the result of our determination that our investment in Great Lakes' long-term value had been adversely impacted by the changing natural gas flows in its market region and that other strategic alternatives to increase its utilization or revenue were no longer feasible. The impairment charge reduced the difference between the carrying value of our investment in Great Lakes and the underlying equity in the net assets, to $260 million and the difference represented 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.

On October 30, 2017, Great Lakes filed a rate settlement with FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement does not contain a moratorium provision and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022. The 2017 Great Lakes Settlement, which was approved by FERC on February 22, 2018, decreased Great Lakes' maximum transportation rates by 27 percent effective October 1, 2017. At December 31, 2017, the estimation of fair value on the remaining equity investment in Great Lakes was completed and we concluded the fair value of our investment in Great Lakes has not materially changed from 2015.

The assumptions we used in the analysis related to the estimated fair value of our remaining equity investment in Great Lakes included the reduction in Great Lakes' rates effective October 1, 2017. The reduction in rates was offset by expected cash flows from the long-term transportation contract with the TransCanada other revenue opportunities on the system and the settlement's elimination of the revenue sharing mechanism with its customers. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have remained positive, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in an additional future impairment of the carrying value of our investment in Great Lakes.

Our key assumptions 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,
- discount rates and multiples used, and
- changes in other long-term strategic objectives.

The summarized financial information provided to us by Great Lakes is as follows:

December 31 (millions of dollars)	**2017**	2016
Assets		
Current assets	**107**	66
Plant, property and equipment, net	**701**	714
	808	780
Liabilities and Partners' Equity		
Current liabilities	**75**	40
Long-term debt, net[a]	**259**	278
Other long term liabilities	**1**	–
Partners' equity	**473**	462
	808	780

Year ended December 31 (millions of dollars)	**2017**	2016	2015
Transmission revenues	**181**	179	177
Operating expenses	**(66)**	(69)	(59)
Depreciation	**(29)**	(28)	(28)
Financial charges and other	**(20)**	(21)	(23)
Net income	**66**	61	67

(a) Includes current maturities of $19 million as of December 31, 2017 (December 31, 2016 – $19 million).

Iroquois

On June 1, 2017, the Partnership, through its interest in TC PipeLines Intermediate Limited Partnership acquired a 49.34 percent interest in Iroquois. For the year ended December 31, 2017, The Partnership received distributions from Iroquois amounting to $27 million which includes the Partnership's 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $5 million (Refer to Note 7). This amount is reported as distributions received as return of investment in the Partnership's consolidated statement of cash flows.

The Partnership recorded no undistributed earnings for the period from June 1, 2017, acquisition date through December 31, 2017. At December 31, 2017, the Partnership had a $41 million difference between the carrying value of Iroquois and the underlying equity in the net assets primarily from TransCanada's carrying value and is due to their fair value assessment of Iroquois' assets at the time of its acquisition of interests from third parties (refer to Note 2-Acquisitions and Goodwill for our accounting policy on acquisitions from TransCanada)

The summarized financial information provided to us by Iroquois for the period from the June 1, 2017 acquisition date through December 31, 2017 is as follows:

(millions of dollars)	**At December 31, 2017**
ASSETS	
Cash and cash equivalents	**86**
Other current assets	**36**
Plant, property and equipment, net	**591**
Other assets	**8**
	721
LIABILITIES AND PARTNERS' EQUITY	
Current liabilities	**17**
Net long-term debt, including current maturities[(a)]	**329**
Other non-current liabilities	**9**
Partners' equity	**366**
	721

Period of 7 months ended December 31 (millions of dollars)	**2017**
Transmission revenues	**110**
Operating expenses	**(32)**
Depreciation	**(17)**
Financial charges and other	**(9)**
Net income	**52**

(a) Includes current maturities of $4 million as of December 31, 2017.

NOTE 6 PLANT, PROPERTY AND EQUIPMENT

The following table includes plant, property and equipment of our consolidated entities:

	2017			2016[(a)]		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**2,577**	**(962)**	**1,615**	2,540	(879)	1,661
Compression	**533**	**(165)**	**368**	519	(148)	371
Metering and other	**182**	**(54)**	**128**	205	(61)	144
Construction in progress	**12**	**–**	**12**	4	–	4
	3,304	**(1,181)**	**2,123**	3,268	(1,088)	2,180

(a) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

NOTE 7 ACQUISITIONS

2017 Acquisition

On June 1, 2017, the Partnership acquired from subsidiaries of TransCanada a 49.34 percent interest in Iroquois, including an option to acquire a further 0.66 percent interest in Iroquois, together with an additional 11.81 percent interest in PNGTS resulting in the Partnership owning a 61.71 percent interest in PNGTS (the 2017 Acquisition). The total purchase price of the 2017 Acquisition was $765 million plus final purchase price adjustments amounting to $50 million. The purchase price consisted of (i) $710 million for the Iroquois interest (less $164 million, which reflected our 49.34 percent share of Iroquois outstanding debt on June 1, 2017), (ii) $55 million for the additional

11.81 percent interest in PNGTS (less $5 million, which reflected our 11.81% proportionate share in PNGTS' outstanding debt on June 1, 2017) (iii) final working capital adjustments for Iroquois and PNGTS amounting to $19 million and $3 million, respectively and (iv) additional consideration of $28 million for the surplus cash on Iroquois' balance sheet. Additionally, the Partnership paid $1,000 for the option to acquire TransCanada's remaining 0.66 percent interest in Iroquois. The Partnership funded the cash portion of the 2017 Acquisition through a combination of proceeds from the May 2017 public debt offering (refer to Note 8) and borrowing under our Senior Credit Facility.

At the date of the 2017 Acquisition, there was significant cash on Iroquois' balance sheet. Pursuant to the Purchase and Sale Agreement associated with the acquisition of the Iroquois interest, as amended, the Partnership agreed to pay $28 million plus interest to TransCanada on August 1, 2017 for its 49.34 percent share of the cash determined to be surplus to Iroquois' operating needs.

Iroquois' partners adopted a distribution resolution to address the surplus cash on its balance sheet post-closing. The Partnership expects to receive the $28 million of unrestricted cash as part of its quarterly distributions from Iroquois over 11 quarters under the terms of the resolution, which began with Iroquois' second quarter 2017 distribution on August 1, 2017. As of February 26, 2018 the Partnership has received approximately $7.8 million of the expected $28 million, of which $5.2 million was received in 2017 and $2.6 million was received on February 1, 2018 (Refer to Note 25).

The acquisition of a 49.34 percent interest in Iroquois was accounted for as a transaction between entities under common control, whereby the equity investment in Iroquois was recorded at TransCanada's carrying value and the total excess purchase price paid was recorded as a reduction in Partners' Equity.

Iroquois' net purchase price was allocated as follows:

(millions of dollars)

Net Purchase Price[(a)]	593
Less: TransCanada's carrying value of Iroquois at June 1, 2017	223
Excess purchase price[(b)]	370

(a) Total purchase price of $710 million plus final working capital adjustment of $19 million and the additional consideration on Iroquois surplus cash amounting to approximately $28 million less the assumption of $164 million of proportional Iroquois debt by the Partnership.

(b) The excess purchase price of $370 million was recorded as a reduction in Partners' Equity.

The acquisition of an additional 11.81 percent interest in PNGTS, which resulted in the Partnership owning 61.71 percent in PNGTS, was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby assets and liabilities of PNGTS were recorded at TransCanada's carrying value and the Partnership's historical financial information, except net income per common unit, was recast to consolidate PNGTS for all periods presented.

The PNGTS purchase price was recorded as follows:

(millions of dollars)

Current assets	25
Property, plant and equipment, net	294
Current liabilities	(4)
Deferred state income taxes	(10)
Long-term debt, including current portion	(41)
	264
Non-controlling interest	(100)
Carrying value of pre-existing Investment in PNGTS	(132)
TransCanada's carrying value of the acquired 11.81 percent interest at June 1, 2017	32
Excess purchase price over net assets acquired[(a)]	21
Total cash consideration[(b)]	53

(a) The excess purchase price of $21 million was recorded as a reduction in Partners' Equity.

(b) Total purchase price of $55 million plus the final working capital adjustment of $3 million less the assumption of $5 million of proportional PNGTS debt by the Partnership.

2016 PNGTS Acquisition

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 $228 million and consisted of $193 million in cash (including the final purchase price adjustment of $5 million) and the assumption of $35 million in proportional PNGTS debt.

The Partnership funded the cash portion of the transaction using proceeds received in 2015 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 acquisition was accounted for as a transaction between entities under common control, whereby the equity investment in PNGTS 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]	193
Less: TransCanada's carrying value of PNGTS' net assets at January 1, 2016	120
Excess purchase price[b]	73

(a) Total purchase price of $228 million less the assumption of $35 million of proportional PNGTS debt by the Partnership.

(b) The excess purchase price of $73 million was recorded as a reduction in Partners' Equity.

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 8). 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 Third Amended and Restated Agreement of Limited Partnership of the Partnership (Partnership Agreement), the Class B distribution was 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.

NOTE 8 DEBT AND CREDIT FACILITIES

(millions of dollars)	2017	Weighted Average Interest Rate for the Year Ended December 31, 2017	2016[b]	Weighted Average Interest Rate for the Year Ended December 31, 2016[b]
TC PipeLines, LP				
Senior Credit Facility due 2021	**185**	2.41%	160	1.72%
2013 Term Loan Facility due 2022	**500**	2.33%	500	1.73%
2015 Term Loan Facility due 2020	**170**	2.22%	170	1.63%
4.65% Unsecured Senior Notes due 2021	**350**	4.65%[a]	350	4.65%[a]
4.375% Unsecured Senior Notes due 2025	**350**	4.375%[a]	350	4.375%[a]
3.90% Unsecured Senior Notes due 2027	**500**	3.90%[a]	–	–
GTN				
5.29% Unsecured Senior Notes due 2020	**100**	5.29%[a]	100	5.29%[a]
5.69% Unsecured Senior Notes due 2035	**150**	5.69%[a]	150	5.69%[a]
Unsecured Term Loan Facility due 2019	**55**	2.02%	65	1.43%
PNGTS				
5.90% Senior Secured Notes due 2018	**30**	5.90%[a]	53	5.90%[a]
Tuscarora				
Unsecured Term Loan due 2020	**25**	2.27%	10	1.64%
3.82% Series D Senior Notes due 2017	**–**	–	12	3.82%[a]
	2,415		1,920	
Less: unamortized debt issuance costs and debt discount	**12**		9	
Less: current portion	**51[d]**		52[c]	
	2,352		1,859	

(a) Fixed interest rate.

(b) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

(c) Includes the PNGTS portion due at December 31, 2016 amounting to $5.5 million that was paid on January 3, 2017.

(d) Includes the PNGTS portion due at December 31, 2017 amounting to $5.8 million that was paid on January 2, 2018.

TC PipeLines, LP

On November 10, 2016, the Partnership's Senior Credit Facility was amended to extend the maturity period through November 10, 2021. The Facility consists of a $500 million senior revolving credit facility with a banking syndicate, under which $185 million was outstanding at December 31, 2017 (December 31, 2016 – $160 million), leaving $315 million available for future borrowing.

At the Partnership's option, the interest rate on the outstanding borrowings under the Senior Credit Facility may be the lenders' base rate or the London Interbank Offered Rate (LIBOR) plus, in either case, an applicable margin that is based on the Partnership's long-term unsecured credit ratings. The Senior Credit Facility permits the Partnership to specify the portion of the borrowings to be covered by specific interest rate options and, for LIBOR-based borrowings, to specify the interest rate period. The Partnership is required to pay a commitment fee based on its credit rating and on the unused principal amount of the commitments under the Senior 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 $500 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 was 2.62 percent at December 31, 2017 (December 31, 2016 – 1.92 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 originally on July 1, 2018. On September 29, 2017, the Partnership's 2013 Term Loan Facility was amended to extend the maturity period through October 2, 2022. 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 2.00 percent for LIBOR borrowings and 0.125 percent and 1.00 percent for base rate borrowings.

As of December 31, 2017, the variable interest rate exposure related to 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 2.31 percent (2016 – 2.31 percent). Prior to hedging activities, the LIBOR-based interest rate was 2.62 percent at December 31, 2017 (December 31, 2016 – 1.87 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. On September 29, 2017, the Partnership's 2015 Term Loan Facility that was due on October 1, 2018 was amended to extend the maturity period through October 1, 2020. The LIBOR-based interest rate on the 2015 Term Loan Facility was 2.51 percent at December 31, 2017 (December 31, 2016 – 1.77 percent).

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]) no greater than 5.00 to 1.00 for each fiscal quarter, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the leverage ratio is to be no greater than 5.50 to 1.00. The leverage ratio was 4.70 to 1.00 as of December 31, 2017.

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 2015 GTN Acquisition (Refer to Note 7) and to reduce the amount outstanding under our Senior Credit Facility. The indenture for the notes contains customary investment grade covenants.

On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 Acquisition (Refer to Note 7). The indenture for the notes contains customary investment grade covenants.

PNGTS

PNGTS' Senior Secured Notes are secured by the PNGTS long-term firm shipper contracts and its partners' pledge of their equity and a guarantee of debt service for six months. PNGTS is restricted under the terms of its note purchase agreement from making cash distributions unless certain conditions are met. Before a distribution can be made, the debt service reserve account must be fully funded and PNGTS' debt service coverage ratio for the preceding and succeeding twelve months must be 1.30 or greater. At December 31, 2017, the debt service coverage ratio was 1.72 for the twelve preceding months and 1.53 for the twelve succeeding months. Therefore, PNGTS was not restricted to make any cash distributions.

GTN

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 was 2.31 percent at December 31, 2017 (December 31, 2016 – 1.57 percent). 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, 2017 is 44.6 percent.

Tuscarora

On August 21, 2017, Tuscarora refinanced all of its outstanding debt by amending its existing Unsecured Term Loan Facility and issuing a new $25 million variable rate term loan that will require yearly principal payments and will mature on August 21, 2020. Tuscarora's Unsecured Term Loan contains a covenant that requires Tuscarora to maintain a debt service coverage ratio (cash available from operations divided by a sum of interest expense and principal payments) of greater than or equal to 3.00 to 1.00. As of December 31, 2017, the ratio was 11.09 to 1.00.

The LIBOR-based interest rate on the Tuscarora's Unsecured Term Loan Facility was 2.49 percent at December 31, 2017 (December 31, 2016 – 1.90 percent).

Partnership (TC PipeLines, LP and its subsidiaries)

At December 31, 2017, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

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

(millions of dollars)	
2018	51
2019	36
2020	293
2021	535
2022	500
Thereafter	1,000
	2,415

NOTE 9 OTHER LIABILITIES

December 31 (millions of dollars)	**2017**	2016
Regulatory liabilities	**26**	25
Other liabilities	**3**	3
	29	28

The Partnership collects estimated future removal costs related to its transmission and gathering facilities in its current rates (also known as "negative salvage") 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 10 PARTNERS' EQUITY

At December 31, 2017, the Partnership had 70,573,423 common units outstanding, of which 53,488,592 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 launched its $200 million ATM program pursuant to which, the Partnership may from time to time, offer and sell, through sales agents, common units, representing limited partner interests.

On August 5, 2016, the Partnership entered into a new $400 million Equity Distribution Agreement (EDA) with five financial institutions (the Managers). Sales of the common units will be issued pursuant to the Partnership's shelf registration statement on Form S-3 (Registration No. 333-211907), which was declared effective by the SEC on August 4, 2016.

In 2017, the Partnership issued 3.2 million common units under the ATM Program generating net proceeds of approximately $173 million, plus an additional $3 million from the General Partner to maintain its effective two percent interest. The commissions to our sales agents were approximately $2 million. The net proceeds were used to repay a portion of the borrowings under the Senior Credit Facility and for general partnership purposes.

In 2016, the Partnership issued 3.1 million common units under the ATM Program generating net proceeds of approximately $164 million, plus an additional $3 million from the General Partner to maintain its effective two percent interest. The commissions to our sales agents were approximately $2 million. The net proceeds were used to repay a portion of the borrowings under the Senior Credit Facility for the 2016 PNGTS Acquisition and for general partnership purposes. The 3.1 million common units issued include the 1.6 million common units subject to rescission as discussed below.

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 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.

Common unit issuance subject to rescission

In connection with a late filing of an employee-related Form 8-K with the SEC in March 2016, the Partnership became ineligible to use the then effective shelf registration statement upon filing of its Annual Report on Form 10-K for the year ended December 31, 2015. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the Partnership's ATM program may have had a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to the Partnership. The Securities Act of 1933, as amended (Securities Act) generally requires that any claim brought for a violation of Section 5 of the Securities Act be brought within one year of violation.

At December 31, 2016, $83 million was recorded as common units subject to rescission on the consolidated balance sheet. The Partnership classified the 1.6 million common units that were sold under its ATM program from March 8, 2016 up to and including May 19, 2016, which may have been subject to rescission rights, outside of equity given the potential redemption feature which was not within the control of the Partnership. These units were treated as outstanding for financial reporting purposes.

No unitholder claimed or attempted to exercise any rescission rights prior to their expiry dates and the final rights related to the sales of such units expired on May 19, 2017. As a result of the expiration of these rights, the $83 million was reclassified back to partners' equity. At December 31, 2017, there were no outstanding common units subject to rescission on the Partnership's consolidated balance sheet.

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 exceeding certain annual thresholds (refer to Note 7). 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 is increased by the excess of 30 percent of GTN's distributions over the annual threshold until such amount is declared for distribution and paid every first quarter of the subsequent year.

For the years ended December 31, 2017, 2016 and 2015, the Class B units' equity account was increased by $15 million, $22 million and $12 million, respectively. These amounts equal 30 percent of GTN's total distributable cash flow above the $20 million threshold in 2017 and 2016 and the $15 million threshold in 2015 (refer to Notes 13 and 14).

NOTE 11 ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The changes in accumulated other comprehensive income (loss) (AOCI) by component are as follows:

(millions of dollars)	**Cash flow hedges**[(a)]	Equity Investments	Total
Balance at December 31, 2014	**(5)**	–	(5)
Change in fair value of cash flow hedges	**–**	–	–
Amounts reclassified from AOCI	**–**	–	–
PNGTS' amortization of realized loss on derivative instrument (Note 19)	**1**	–	1
Net other comprehensive income	**1**	–	1
Balance at December 31, 2015	**(4)**	–	(4)
Change in fair value of cash flow hedges	**3**	–	3
Amounts reclassified from AOCI	**(2)**	–	(2)
PNGTS' amortization of realized loss on derivative instrument (Note 19)	**1**	–	1
Net other comprehensive income	**2**	–	2
Balance at December 31, 2016	**(2)**	–	(2)
Change in fair value of cash flow hedges	**5**	–	5
Amounts reclassified from AOCI	**–**	–	–
PNGTS' amortization of realized loss on derivative instrument (Note 19)	**1**	–	1
Other comprehensive income – effects of Iroquois' retirement benefit plans	**–**	1	1
Net other comprehensive income	**6**	1	7
Balance as of December 31, 2017	**4**	1	5

(a) Recast to consolidate PNGTS (Refer to in Notes 2 and 7). Additionally, AOCI as presented here is net of non-controlling interest on PNGTS.

NOTE 12 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	**2017**	2016[(a)]	2015[(a)]
Interest expense[(b)]	**83**	69	65
Net realized loss related to the interest rate swaps	**–**	3	2
PNGTS' amortization of realized loss on derivative instrument (Note 19)	**1**	1	1
Other	**(2)**	(2)	(5)
	82	71	63

(a) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

(b) Interest expense includes amortization of debt issuance costs and discount costs.

NOTE 13 NET INCOME PER COMMON UNIT

Net income (loss) per common unit is computed by dividing net income (loss) attributable to controlling interests, after deduction of net income attributed to PNGTS' former parent, amounts attributable to the General Partner and Class B units, 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 14).

The amount allocable to the Class B units in 2017 equals an amount based upon 30 percent of GTN's distributable cash flow during the year ended December 31, 2017 less $20 million (2016 – $20 million; 2015 – $15 million).

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

(millions of dollars, except per common unit amounts)	**2017**	2016	2015
Net income attributable to controlling interests[(a)]	**252**	248	37
Net income attributable to PNGTS' former parent[(a)(b)]	**(2)**	(4)	(24)
Net income allocable to General Partner and Limited Partners	**250**	244	13
Incentive distributions attributable to the General Partner[(c)]	**(12)**	(7)	(3)
Net income attributable to the Class B units[(d)]	**(15)**	(22)	(12)
Net income (loss) allocable to the General Partner and common units	**223**	215	(2)
Net income allocable to the General Partner's two percent interest	**(4)**	(4)	–
Net income (loss) attributable to common units	**219**	211	(2)
Weighted average common units outstanding *(millions)* – basic and diluted	**69.2**	65.7[(e)]	63.9
Net income (loss) per common unit – basic and diluted[(f)]	**$3.16**	$3.21	$(0.03)

(a) Recast to consolidate PNGTS for years ended December 2016 and 2015 (Refer to Note 2).

(b) Net income allocable to General and Limited Partners excludes net income attributed to PNGTS' former parent as it was allocated to TransCanada and was not allocable to either the general partner, common units or Class B units.

(c) Under the terms of the Partnership Agreement, for any quarterly period, the participation of the incentive distribution rights (IDRs) is limited to the available cash distributions declared. Accordingly, incentive distributions allocated to the General Partner are based on the Partnership's available cash during the current reporting period, but declared and paid in the subsequent reporting period.

(d) As discussed in Note 10, the Class B units entitle TransCanada to a distribution which is an amount based on 30 percent of GTN's distributions after exceeding 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 the Class B units a distribution in an amount equal to 30 percent of GTN's total distributable cash flows during the year ended December 31, 2017 less the threshold level of $20 million (2016 – less $20 million; 2015 – less $15 million). During the year ended December 31, 2017, 30 percent of GTN's total distributable cash flow was $35 million. As a result of exceeding the threshold level of

$20 million, $15 million of net income attributable to controlling interests was allocated to the Class B units at December 31, 2017 (2016 – $22 million; 2015 – $12 million) (Refer to Note 10).

(e) Includes the common units subject to rescission. These units are treated as outstanding for financial reporting purposes (Refer to Note 10).

(f) Net income (loss) per common unit prior to recast.

NOTE 14 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
1/22/2015	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	2/12/2016	$0.89	$57	$12[d]	$1	$1	$71
4/21/2016	5/13/2016	$0.89	$58	$ –	$1	$1	$60
7/21/2016	8/12/2016	$0.94	$62	$ –	$1	$2	$65
10/20/2016	11/14/2016	$0.94	$63	$ –	$1	$2	$66
1/23/2017	2/14/2017	$0.94	$64	$22[e]	$2	$2	$90
4/25/2017	5/15/2017	$0.94	$65	$ –	$1	$2	$68
7/20/2017	8/11/2017	$1.00	$69	$ –	$2	$3	$74
10/24/2017	11/14/2017	$1.00	$70	$ –	$1	$3	$74
1/23/2018[b]	2/13/2018[b]	$1.00	$71	$15[f]	$2	$3	$91

(a) The distributions paid during the year ended December 31, 2017 included incentive distributions to the General Partner of $10 million (2016 – $6 million, 2015 – $2 million).

(b) On February 13, 2018, we paid a cash distribution of $1.00 per unit on our outstanding common units to unitholders of record at the close of business on February 2, 2018 (refer to Note 25).

(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 exceeding certain annual thresholds (refer to Note 7 and 10).

(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.

(e) On February 14, 2017, we paid TransCanada $22 million representing 30 percent of GTN's total distributable cash flows for the year ended December 31, 2016 less $20 million (refer to Note 10 and 25).

(f) On February 13, 2018, we paid TransCanada $15 million representing 30 percent of GTN's total distributable cash flows for the year ended December 31, 2017 less $20 million (refer to Note 10 and 25).

NOTE 15 CHANGE IN OPERATING WORKING CAPITAL

Year Ended December 31 (millions of dollars)	2017	2016[b]	2015[b]
Change in accounts receivable and other	**4**	(4)	6
Change in other current assets	**2**	(4)	(1)
Change in accounts payable and accrued liabilities	**(7)[a]**	5[a]	(2)
Change in accounts payable to affiliates	**(3)**	–	(15)[a]
Change in state income taxes payable	**–**	–	(5)
Change in accrued interest	**2**	2	(3)
Change in operating working capital	**(2)**	(1)	(20)

(a) Excludes certain non-cash items primarily related to capital accruals and dropdown costs.

(b) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

NOTE 16 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 consolidated recasted revenues (refer to Note 2) for the years ended December 31, 2017, 2016 and 2015:

Year Ended December 31 (millions of dollars)	2017	2016	2015
Anadarko Energy Services Company (Anadarko)	**48**	48	48
Pacific Gas and Electric Company (Pacific Gas)	**33[a] [b]**	36[a]	42

At December 31, 2017 and 2016, Anadarko owed the Partnership approximately $4 million, which is approximately 10 percent of our consolidated recasted trade accounts receivable (Refer to Note 2).

(a) Less than 10 percent of trade accounts receivable

(b) Less than 10 percent of consolidated revenue

NOTE 17 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 $4 million for the year ended December 31, 2017 (2016 – $3 million, 2015 – $3 million).

As operator of most of our pipelines (except Iroquois and the PNGTS joint facilities) TransCanada's subsidiaries provide capital and operating services to 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. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The PNGTS joint facilities are operated by MNOC. Therefore, Iroquois and the PNGTS joint facilities do not receive capital and operating services from TransCanada.

Capital and operating costs charged to our pipeline systems, except for Iroquois, for the years ended December 31, 2017, 2016 and 2015 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2017 and 2016 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2017**	2016	2015
Capital and operating costs charged by TransCanada's subsidiaries to:			
Great Lakes[(a)]	**36**	30	30
Northern Border[(a)]	**43**	32	36
PNGTS[(a)(b)]	**9**	8	8
GTN[(a)(c)]	**34**	27	30
Bison	**6**	2	4
North Baja	**4**	4	5
Tuscarora	**4**	5	4
Impact on the Partnership's net income attributable to controlling interests:			
Great Lakes	**15**	13	13
Northern Border	**16**	12	14
PNGTS[(b)]	**5**	5	5
GTN[(c)]	**29**	24	25
Bison	**6**	3	4
North Baja	**4**	4	5
Tuscarora	**4**	4	4

December 31 (millions of dollars)	**2017**	2016
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
Great Lakes[(a)]	**3**	4
Northern Border[(a)]	**4**	4
PNGTS[(a)(b)]	**1**	1
GTN	**3**	3
Bison	**1**	1
North Baja	**–**	1
Tuscarora	**–**	1

(a) Represents 100 percent of the costs.

(b) Recast to consolidate PNGTS for years ended December 31, 2016 and 2015 (Refer to Note 2).

(c) In 2015, the Partnership acquired the remaining 30 percent interest in GTN (Refer to Note 7).

Great Lakes

Great Lakes earns significant transportation revenues from TransCanada and its affiliates, some of which are provided at discounted rates, negotiated rates and some at maximum recourse rates. For the year ended December 31, 2017, Great Lakes earned 57 percent of its transportation revenues from TransCanada and its affiliates (2016 – 68 percent; 2015 – 71 percent). Additionally, Great Lakes earned approximately one percent of its total revenues as affiliated rental revenue in 2017 (2016 – 1 percent; 2015 – 1 percent).

At December 31, 2017, $20 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2016 – $19 million).

In 2017, Great Lakes operates under a FERC approved 2013 rate settlement that includes a revenue sharing mechanism that requires Great Lakes to share with its customers certain percentages of any qualifying revenues earned above certain ROEs. A refund of $7 million was paid to shippers in 2017 relating to the year ended December 31, 2016, of which approximately 86 percent was made to affiliates of Great Lakes. For the year ended December 31, 2017, Great Lakes has recorded an estimated revenue sharing provision amounting to $40 million and Great Lakes expects that a significant percentage of the 2017 revenue sharing refund will be to its affiliates.

Under the terms of the 2017 Great Lakes Settlement, beginning 2018, the revenue sharing was eliminated (refer to Note 5. Additionally, effective October 1, 2017, Great Lakes still charged customers rates in effect prior to the 2017 Great Lakes Settlement but only recognized revenue up to the amount of the new rates in the 2017 Great Lakes Settlement. The difference between these two amounts was recognized as a provision for rate refund (liability) on Great Lakes' balance sheet amounting to $8 million. Great Lakes expects that a significant percentage of the provision for rate refund will be to its affiliates as well.

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. At December 31, 2017 and 2016, Great Lakes has an outstanding receivable from this arrangement amounting to $64 million and $27 million, respectively.

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, 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.

On April 24, 2017, Great Lakes reached an agreement on the terms of a new long-term transportation capacity contract with its affiliate, TransCanada. The contract, which was subject to Canada's National Energy Board (NEB) approval, is for a term of 10 years and allows TransCanada the ability to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system from the Manitoba/U.S. border to the U.S. border near Dawn Ontario. On September 21, 2017, TransCanada received approval from the NEB and as a result, this contract commenced on November 1, 2017. This contract contains volume reduction options up to full contract quantity beginning in year three. For the year ended December 31, 2017, the total revenue earned by Great Lakes on this contract was $13 million.

PNGTS

For the years ended December 31, 2017, 2016 and 2015, PNGTS provided transportation services to a related party. Revenues from TransCanada Energy Ltd., a subsidiary of TransCanada, for 2017, 2016 and 2015 were approximately $1 million, $2 million and $3 million, respectively. At December 31, 2017, PNGTS had nil million outstanding receivables from TransCanada Energy Ltd. in the consolidated balance sheets.

In connection with anticipated future commercial opportunities, PNGTS has entered into an arrangement with its affiliates regarding the construction of certain facilities on their systems that will be required to fulfill future contracts on the PNGTS' system. In the event the anticipated developments do not proceed, PNGTS will be required to reimburse its affiliates for any costs incurred related to the development of these facilities. As of December 31, 2017, the total costs incurred by these affiliates was approximately $3 million.

NOTE 18 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2017 and 2016:

Quarter ended (millions of dollars except per common unit amounts)	Mar 31	Jun 30	Sept 30	Dec 31
2017				
Transmission revenues	**112**	**101**	**100**	**109**
Equity earnings	**36**	**24**	**27**	**37**
Net income	**83**	**55**	**55**	**70**
Net income attributable to controlling interests	**77**	**55**	**54**	**66**
Net income per common unit	**$1.05**	**$0.73**	**$0.61**	**$0.77**
Cash distribution paid to common units[(a)]	**68**	**68**	**74**	**74**
Cash distribution paid to Class B units	**22**	**–**	**–**	**–**
2016				
Transmission revenues[(b)]	111	101	103	111
Equity earnings[(b)]	33	20	22	22
Net income[(b)]	81	57	60	65
Net income attributable to controlling interests[(b)]	74	55	58	61
Net income per common unit[(c)]	$1.10	$0.76	$0.65	$0.70
Cash distribution paid to common unit[(c)]	59	60	65	66
Cash distribution paid to Class B units	12	–	–	–

(a) Distributions paid to common units includes our general partner's effective two percent share and IDRs.

(b) Recast to consolidate PNGTS for the year ended December 31, 2016 (Refer to Note 2).

(c) Historical net income per common unit was not recasted.

NOTE 19 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 Partnership has classified the fair value of natural gas imbalances as a Level 2 of the fair value hierarchy for fair value disclosure purposes, as the valuation approach includes quoted prices in the market index and observable volumes for the imbalance.

Long-term debt is recorded at amortized cost and classified in Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified in Level 2 for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. The estimated fair value of the Partnership's debt as at December 31, 2017 and December 31, 2016 was $2,475 million and $1,963 million, respectively.

The common units subject to rescission as presented in the December 31, 2016 balance sheet, as discussed more fully in Note 10, were measured using the original issuance price, plus statutory interest and less any distributions paid. This fair value measurement is classified as Level 2.

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 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. The Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps maturing July 1, 2018, at a weighted average fixed interest rate of 2.31 percent. At December 31, 2017, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $5 million (on both gross and net basis). At December 31, 2016, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $1 million and a liability of $1 million (on a gross basis) and an asset of nil million (on a net basis). The Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges for the years ended December 31, 2017, 2016 and 2015. The net change in fair value of interest rate derivative instruments recognized in other comprehensive income was a gain of $5 million for the year ended December 31, 2017 (2016 – gain of $2 million, 2015 – nil). In 2017, the net realized loss related to the interest rate swaps was nil, and was included in financial charges and other (2016 – $3 million, 2015 – $2 million). Refer to Note 12 – Financial Charges and Other.

As discussed in Note 8, the Partnership's $500 million 2013 Term Loan that was due July 1, 2018, was amended to extend the maturity period through October 2, 2022. As a result of this extension, the Partnership implemented an interest rate hedging strategy during the fourth quarter of 2017 and hedged the entire $500 million until its October 2, 2022 maturity using forward starting swaps at an average rate of 3.26 percent.

The Partnership has no master netting agreements, however, its 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 net asset of $5 million as of December 31, 2017 and there would be no effect on the consolidated balance sheet as of December 31, 2016.

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with ASC 815, *Derivatives and Hedging*. PNGTS settled its position with a payment of $20.9 million to counterparties at the time of the refinancing and recorded the realized loss in AOCI as of the termination date. The previously recorded AOCI is currently being amortized against earnings over the life of the PNGTS Senior Secured Notes. At December 31, 2017, our 61.71 percent proportionate share of net unamortized loss on PNGTS included in AOCI was $1 million (2016 – $2 million). For the year ended December 31, 2017, 2016 and 2015, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $0.8 million for each year.

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 cash and cash equivalents and receivables, 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, 2017, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2017, we had a credit risk concentration on one of our customers and the amount owed is greater than 10 percent of our trade accounts receivable (refer to Note 16).

(c) Other

The estimated fair value measurement on our equity investment in Great Lakes is classified as Level 3. In the determination of fair value, we used internal forecasts on expected future cash flows and applied appropriate discount rates. The determination of expected future cash flows involved significant assumptions and estimates as discussed more fully in Note 5.

NOTE 20 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2017**	2016[(a)]
Trade accounts receivable, net of allowance of nil	**40**	44
Imbalance receivable from affiliates	**1**	2
Other	**1**	1
	42	47

(a) Recast to consolidate PNGTS (Refer to Notes 2 and 7).

NOTE 21 REGULATORY

GTN – GTN operates under rates established pursuant to a settlement approved by FERC in June 2015. Beginning in January 2016, GTN's rates decreased by 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.

Tuscarora – Tuscarora operates under rates established pursuant to a settlement approved by FERC in September 2016. Under the settlement, Tuscarora's system-wide unit rate initially decreased by 17 percent, effective August 1, 2016. Unless superseded by a subsequent rate case or settlement, this rate will remain in effect until July 31, 2019, after which time the unit rate will decrease by an additional seven percent from August 1, 2019 through July 31, 2022. The settlement does not contain a rate moratorium and requires Tuscarora to file to establish new rates no later than August 1, 2022.

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.

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, 2017, North Baja notified FERC that current market conditions do not support the replacement of the compression that was temporarily abandoned in 2013 and requested authorization to permanently abandon two compressor units and a nominal volume of unsubscribed firm capacity. FERC approved the permanent abandonment request on February 16, 2017. The requested abandonments will not have any impact on existing firm transportation service.

PNGTS – PNGTS continues to operate under the rates approved by FERC in February 2015 (Refer to Note 2 – Significant Accounting Policies – Revenue Recognition). PNGTS has no requirement to file a new rate proceeding.

NOTE 22 CONTINGENCIES

The Partnership and its pipeline systems are subject to various legal proceedings in the ordinary course of business. Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the 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*. We base these estimates on currently available facts and the estimates of the ultimate outcome or resolution. Actual results may differ from estimates resulting in an impact, positive or negative, on earnings and cash flow. Contingencies that might result in a gain are not accrued in our consolidated financial statements.

Below is a material legal proceeding that might have a significant impact on the Partnership:

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 (Essar Minnesota) and certain Foreign 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 Eighth Circuit (Eighth 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 Eighth Circuit heard the appeal on October 20, 2016. A decision on the appeal was received in December 2016 and the Eighth Circuit vacated Great Lakes' judgment against Essar finding that there was no federal jurisdiction. Great Lakes filed a Request for Rehearing with the Eighth Circuit and it was denied in January 2017. Before the Circuit Court issued its decision, Essar Minnesota filed for bankruptcy in July 2016. The Foreign Essar Affiliates have not filed for bankruptcy. Following the Circuit Court's decision, the performance bond was released into the bankruptcy court proceedings. Great Lakes filed a claim against Essar Minnesota in the bankruptcy court and its case against the Foreign Essar Affiliates in

Minnesota state court remains pending. In April 2017, after Great Lakes agreement with creditors on an allowed claim, the bankruptcy court approved Great Lakes' claim in the amount of $31.5 million. On May 20, 2017, the federal district court awarded Essar Minnesota approximately $1.2 million for costs, including recovery of the performance bond premium, to be paid by Great Lakes. Great Lakes filed a motion with the bankruptcy court to offset the $1.2 million award of costs against its claim against Essar Minnesota in the bankruptcy proceeding but was unsuccessful. As a result, Great Lakes accrued the $1.2 million in its books. Great Lakes is unable to estimate the timing or the extent to which its claim will be recoverable in the bankruptcy proceedings.

NOTE 23 VARIABLE INTEREST ENTITIES

In the normal course of business, the Partnership must re-evaluate its legal entities under the current consolidation guidance to determine if those that are considered to be VIEs are appropriately consolidated or if they should be accounted for under other GAAP. A variable interest entity (VIE) is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains or losses of the entity. A VIE is appropriately consolidated if the Partnership is considered to be the primary beneficiary. The VIE's primary beneficiary is the entity that has both (1) the power to direct the activities of the VIE that most significantly impact the VIEs economic performance and (2) the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

As a result of its analysis, the Partnership continues to consolidate all legal entities in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs where the Partnership is not the primary beneficiary, but has a variable interest in the entity, are accounted for as equity investments.

Consolidated VIEs

The Partnership's consolidated VIEs consist of the Partnership's ILPs that hold interests in the Partnership's pipeline systems. After considering the purpose and design of the ILPs and the risks that they were designed to create and pass through to the Partnership, the Partnership has concluded that it is the primary beneficiary of these ILPs because of the significant amount of variability that it absorbs from the ILPs' economic performance.

The assets and liabilities held through these VIEs that are not available to creditors of the Partnership and whose investors have no recourse to the credit of the Partnership are held through GTN, Tuscarora, Northern Border, Great Lakes, PNGTS and Iroquois due to their third party debt. The following table presents the total assets and liabilities of these entities that are included in the Partnership's Consolidated Balance Sheets:

(millions of dollars)	**December 31, 2017**	December 31, 2016[b]
ASSETS (LIABILITIES)[a]		
Cash and cash equivalents	**19**	14
Accounts receivable and other	**30**	33
Inventories	**6**	6
Other current assets	**5**	6
Equity investments	**1,213**	918
Plant, property and equipment	**1,133**	1,146
Other assets	**1**	2
Accounts payable and accrued liabilities	**(24)**	(21)
Accounts payable to affiliates, net	**(42)**	(32)
Distributions payable	**(1)**	(3)
Accrued interest	**(2)**	(2)
Current portion of long-term debt	**(51)**	(52)
Long-term debt	**(308)**	(337)
Other liabilities	**(26)**	(25)
Deferred state income tax	**(10)**	(10)

(a) North Baja and Bison, which are also assets held through our consolidated VIEs, are excluded as the assets of these entities can be used for purposes other than the settlement of the VIE's obligations.

(b) Recast to consolidate PNGTS for the year ended December 31, 2016 (Refer to Note 2).

NOTE 24 INCOME TAXES

The state of New Hampshire (NH) imposes a business profits tax (BPT) levied at the PNGTS level. As a result of the BPT, PNGTS recognizes deferred taxes related to temporary differences between the financial statement carrying amount of existing assets and liabilities and their respective tax bases. The deferred taxes at December 31, 2017, 2016 and 2015 relate primarily to utility plant. For the years ended December 31, 2017, 2016 and 2015, the NH BPT effective tax rate was 3.8 percent for all periods and was applied to PNGTS' taxable income.

The state income taxes of PNGTS are broken out as follows:

Year ended December 31 (millions of dollars)	**2017**	2016[a]	2015[a]
State income taxes			
Current	**1**	1	(2)
Deferred	**–**	–	4
	1	1	2

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 7).

NOTE 25 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through February 26, 2018, 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.

Partnership

On January 23, 2018, the board of directors of our General Partner declared the Partnership's fourth quarter 2017 cash distribution in the amount of $1.00 per common unit and was paid on February 13, 2018 to unitholders of record as of February 2, 2018. The declared distribution totaled $76 million and was paid in the following manner: $71 million to common unitholders (including $6 million to the General Partner as holder of 5,797,106 common units and $11 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $5 million to our General Partner, which included $2 million for its effective two percent general partner interest and $3 million of IDRs payment.

On January 23, 2018, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $15 million which was paid on February 13, 2018. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2017 less $20 million.

Northern Border

Northern Border declared its December 2017 distribution of $15 million on January 8, 2018, of which the Partnership received its 50 percent share or $7 million on January 31, 2018.

Northern Border declared its January 2018 distribution of $17 million on February 14, 2018, of which the Partnership will receive its 50 percent share or $9 million on February 28, 2018.

Great Lakes

Great Lakes declared its fourth quarter 2017 distribution of $20 million on January 10, 2018, of which the Partnership received its 46.45 percent share or $9 million on February 1, 2018.

Iroquois

Iroquois declared its fourth quarter 2017 distribution of $29 million on January 22, 2018, of which the Partnership received its 49.34 percent share or $14 million on February 1, 2018. The $14 million includes our proportionate share of Iroquois' unrestricted cash amounting to $2.6 million (refer to Note 7).

PNGTS

On January 2, 2018, PNGTS paid the amount due on December 31, 2017 on its 2003 Senior Secured Notes amounting to $6 million representing $6 million in principal and nil in interest pursuant to the terms of the Note Purchase agreement. Under the agreement, any principal and interest that is due on a date other than a normal business day shall be made on the next succeeding business day without additional interest or penalty.

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, 2017 and 2016, 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, 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 16, 2018

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, 2017 and 2016 (In thousands)	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	$ 14,010	13,535
Accounts receivable	24,738	23,484
Related party receivables	3,049	3,503
Materials and supplies	5,216	5,727
Prepaid expenses and other	3,761	3,482
Total current assets	50,774	49,731
Property, plant and equipment:		
In service natural gas transmission plant	2,605,625	2,584,065
Construction work in progress	5,692	1,409
Total property, plant and equipment	2,611,317	2,585,474
Less: Accumulated provision for depreciation and amortization	1,548,635	1,496,860
Property, plant and equipment, net	1,062,682	1,088,614
Other assets:		
Regulatory assets	13,994	14,773
Other	7	7
Total other assets	14,001	14,780
Total assets	$1,127,457	1,153,125
Liabilities and Partners' Equity		
Current liabilities:		
Accounts payable	$ 9,737	9,568
Related party payables	4,154	3,507
Accrued taxes other than income	19,609	20,286
Accrued interest	4,691	4,707
Other	243	196
Total current liabilities	38,434	38,264
Long-term debt, net	264,056	429,545
Deferred credits and other liabilities		
Regulatory liabilities	27,031	24,473
Other	4,336	3,931
Total deferred credits and other liabilities	31,367	28,404
Total liabilities	333,857	496,213
Partners' equity:		
Partners' capital	794,869	658,466
Accumulated other comprehensive loss	(1,269)	(1,554)
Total partners' equity	793,600	656,912
Total liabilities and partners' equity	$1,127,457	1,153,125

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

Years ended December 31, 2017, 2016, and 2015 (In thousands)	**2017**	2016	2015
Operating revenue	**$291,396**	291,642	285,510
Operating expenses:			
Operations and maintenance	**54,374**	47,652	47,260
Depreciation and amortization	**59,426**	58,813	59,571
Taxes other than income	**23,480**	24,200	22,826
Operating expenses	**137,280**	130,665	129,657
Operating income	**154,116**	160,977	155,853
Interest expense:			
Interest expense	**22,257**	25,433	26,591
Interest expense capitalized	**(176)**	(100)	(76)
Interest expense, net	**22,081**	25,333	26,515
Other income (expense):			
Allowance for equity funds used during construction	**573**	297	243
Other income	**3,936**	4,151	4,722
Other expense	**(238)**	(113)	(420)
Other income, net	**4,271**	4,335	4,545
Net income to partners	**$136,306**	139,979	133,883

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2017, 2016, and 2015 (In thousands)	**2017**	2016	2015
Net income to partners	**$136,306**	139,979	133,883
Other comprehensive income:			
Changes associated with hedging transactions	**285**	264	245
Total comprehensive income	**$136,591**	140,243	134,128

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

Years ended December 31, 2017, 2016, and 2015 (In thousands)		2017	2016	2015
Cash flows from operating activities:				
Net income to partners	$	**136,306**	139,979	133,883
Adjustments to reconcile net income to partners to net cash provided by operating activities:				
Depreciation and amortization		**59,426**	58,813	59,571
Allowance for equity funds used during construction		**(573)**	(297)	(243)
Changes in components of working capital		**(1,411)**	217	(7,644)
Other		**406**	45	1,843
Total adjustments		**57,848**	58,778	53,527
Net cash provided by operating activities		**194,154**	198,757	187,410
Cash flows used in investing activities:				
Capital expenditures		**(27,054)**	(21,592)	(15,348)
Other		**(722)**	(982)	(3,417)
Net cash used in investing activities		**(27,776)**	(22,574)	(18,765)
Cash flows used in financing activities:				
Equity contributions from partners		**166,000**	–	–
Distributions to partners		**(165,903)**	(209,792)	(182,173)
Proceeds from issuance of debt		**–**	128,000	10,000
Repayment of debt		**(166,000)**	(108,000)	(10,000)
Debt issuance costs		**–**	(150)	(564)
Net cash used in financing activities		**(165,903)**	(189,942)	(182,737)
Net change in cash and cash equivalents		**475**	(13,759)	(14,092)
Cash and cash equivalents at beginning of year		**13,535**	27,294	41,386
Cash and cash equivalents at end of year	$	**14,010**	13,535	27,294
Supplemental disclosure for cash flow information:				
Cash paid for interest, net of amount capitalized	$	**21,301**	26,746	25,802
Accruals for property, plant and equipment		**2,592**	63	1,841
Changes in components of working capital:				
Accounts receivable	$	**(1,254)**	(973)	1,220
Related party receivables		**454**	(1,163)	(742)
Materials and supplies		**511**	(78)	(109)
Prepaid expenses and other		**319**	374	(118)
Accounts payable		**(1,702)**	3,369	(1,183)
Related party payables		**709**	318	(6,507)
Accrued taxes other than income		**(676)**	520	(188)
Accrued interest		**(15)**	(2,150)	(17)
Other current liabilities		**243**	–	–
Total	$	**(1,411)**	217	(7,644)

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, 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 to partners	(91,086)	(91,087)	–	(182,173)
Partners' equity at December 31, 2015	$ 364,139	364,140	(1,818)	726,461
Net income to partners	69,990	69,989	–	139,979
Changes associated with hedging transactions	–	–	264	264
Distributions to partners	(104,896)	(104,896)	–	(209,792)
Partners' equity at December 31, 2016	$ 329,233	329,233	(1,554)	656,912
Net income to partners	68,153	68,153	–	136,306
Changes associated with hedging transactions	–	–	285	285
Contributions from partners	83,000	83,000	–	166,000
Distributions to partners	(82,952)	(82,951)	–	(165,903)
Partners' equity at December 31, 2017	$ 397,434	397,435	(1,269)	793,600

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

1. DESCRIPTION OF BUSINESS

Northern Border Pipeline Company (the Partnership) is a Texas general partnership formed in 1978. The Partnership owns a 1,263-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, 2017 and 2016 were as follows:

Partner	Ownership
ONEOK Partners Intermediate Limited Partnership (ONEOK)	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 2017 and 2016 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 inventories primarily consist of materials and supplies and are carried at lower of weighted average cost or market.

(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 (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations*, provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. 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, 2017 and 2016:

	December 31,		Remaining recovery/ settlement period
	2017	2016	
	(In thousands)		(Years)
Regulatory Assets			
Fort Peck lease option	$ 12,149	12,466	38
Pipeline extension project	1,845	2,307	4
Volumetric fuel tracker	1,161	1,387	(a)
Compressor usage surcharge	823	–	(b)
	15,978	16,160	
Less: Current portion included in Prepaid expenses and other	1,984	1,387	
	$ 13,994	14,773	
Regulatory Liabilities			
Negative salvage	$ 27,031	24,473	(c)
Compressor usage surcharge	–	196	(b)
	27,031	24,669	
Less: Current portion included in Other	–	196	
	$ 27,031	24,473	

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

(b) 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 5(b))

(c) 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% to 20% per year. Using these rates, the remaining depreciable life of these assets ranges from 1 to 37 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, 2017 and 2016, there are no refund 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, 2017 and 2016. 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 and discounts incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount or premiums. In addition, amortization of debt issuance costs, premiums, and discounts are reported as part of interest expense.

(m) 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.

(n) Commitments

The Partnership has non-cancelable leases for office space and rights-of-way commitments. The Partnership records expenses straight-line over the life of the of these arrangements.

(o) Income Taxes

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

(p) Fair Value Measurements

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 the Partnership for debt with similar terms and remaining maturities. Considerable judgment is required in developing these estimates.

3. ACCOUNTING CHANGES

(a) Changes in Accounting Policies for 2017

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The new guidance specifies that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance was effective January 1, 2017, and was applied prospectively and did not have a material impact on the Partnership's balance sheets.

(b) Future Accounting Changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognizes revenue with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which the company expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. The Partnership will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. The Partnership will adopt the guidance using the modified retrospective approach with the cumulative-effect of the adjustment recognized at the date of adoption, subject to allowable and elected practical expedients.

The Partnership has identified all existing customer contracts that are within the scope of the new guidance. The Partnership has completed its analysis and has not identified any material differences in the amount and timing of revenue recognition through. The Partnership will not require a cumulative-effect adjustment to opening partners' equity on January 1, 2018.

Although revenues will not be materially impacted by the guidance, the Partnership will be required to add significant disclosures based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating when and how revenue is recognized and information related to contract assets and deferred revenues. In addition, the new guidance requires that the Partnership's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenue and cash flows generated from contracts with customers. The Partnership has addressed system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease requiring the customer to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset in order for the arrangement to qualify as a lease. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

The new guidance is effective on January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership is continuing to identify and analyze existing lease agreements to determine the effect of adoption of the new guidance on its consolidated financial statements. The Partnership is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance. The Partnership continues to monitor and analyze additional guidance and clarification provided by FASB.

4. U.S. TAX REFORM IMPACT

On December 22, 2017, the President of the United States signed into law H.R. 1 (the Tax Cuts and Jobs Act). This legislation provides for major changes to U.S. corporate federal tax law; including a reduction in the U.S. corporate tax rate to 21 percent from 35 percent. As a Texas general partnership, the Partnership is a non-taxable pass through entity and income taxes owed as a result of the Partnership's earnings are the responsibility of each partner, therefore no amounts have been recorded in the Partnership's financial statements as a result of the Tax Cuts and Jobs Act.

The Partnership is regulated by the FERC, which approves its rates, the most recent of which were established through a negotiated settlement that did not ascribe any specific cost of service elements to income taxes. While the FERC also evaluates the Partnership's rate of return on an overall cost-of-service basis, they provide for a recovery of the Partnership's ultimate taxable owners' income tax expense and related balance sheet accounts as components of the maximum recourse rates that may be charged to customers. As a non-taxable pass through entity, the Partnership does not recognize income tax expense nor has it established deferred income tax assets or liabilities. Income tax related expenses, benefits, assets, and liabilities attributable to regulated operations are the responsibility of the ultimate taxable owners of the Partnership and any adjustment to income tax accounts following the Tax Cuts and Jobs Act must be evaluated by those owners.

The Partnership cannot predict the ultimate impact; if any, of lower U.S. corporate tax rates on its future revenues. If in the future the FERC were to require a change in the Partnership's maximum recourse rates related to the change in the U.S. corporate tax rate, the Partnership expects rates would be revised through future rate proceedings or other regulatory action.

At December 31, 2017, the Partnership considers its assessment of the impact of the Tax Cuts and Jobs Act to be its best interpretation of available guidance. Should additional guidance on the impact of the Tax Cuts and Jobs Act on non-taxable partnerships be provided by regulatory, tax and accounting authorities or other sources in the future, the Partnership will review the approach used and adjust as appropriate.

5. CONTINGENCIES AND COMMITMENTS

(a) Contingencies

The Partnership is subject to various legal proceedings in the ordinary course of business. The accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. The Partnership accrues for these contingencies when the 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*. The Partnership bases these estimates on currently available facts and the estimates of the ultimate outcomes or resolution. Actual results may vary from estimates resulting in an impact, positive or negative, on results of operations and cash flows. The Partnership is not aware of any contingent liabilities that would have a material adverse effect on the Partnership's financial condition, results of operations, or cash flows.

(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 FERC approved settlement agreement (2012 Settlement) with its customers and requires the Partnership to file for new rates no later than January 1, 2018. On December 4, 2017, Northern Border filed a rate settlement with FERC precluding the need to file a general rate case by January 1, 2018 (2017 Settlement). The 2017 Settlement, if approved by FERC, provides for tiered rate reductions beginning January 1, 2018, with no change to the underlying rate design. The 2017 Settlement does not contain any moratorium and unless superseded by a subsequent rate case or settlement, recourse rates in effect at December 31, 2017, will decrease by 5.0% on January 1, 2018; by an additional 5.5% on April 1, 2018; and by a further 2.0% beginning January 1, 2020 through December 31, 2023, when the Partnership will be required to establish new rates. This equates to an overall rate reduction of 12.5% by January 1, 2020 from the recourse rates in effect at December 31, 2017.

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 reported as current asset or current liability on the balance sheets. The compressor usage surcharge rate is adjusted annually. The current asset or current liability 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, 2017 and 2016, the Partnership had recorded $0.8 million as prepaid expenses other and $0.2 million as other current liabilities, respectively, on the accompanying balance sheets for the net over and under recoveries of compressor usage related costs.

(c) Commitments

The Partnership makes payments under non-cancelable leases on office space and rights-of-way commitments. The Partnership's expense incurred for these commitments was $3.0 million for each of the years ended December 31, 2017, 2016, and 2015, respectively. The Partnership's future minimum payments on these arrangements are as follows:

Year Ending (In thousands)	Rights-of-Way	Office Space	Total
2018	2,214	393	2,607
2019	2,215	393	2,608
2020	2,232	211	2,443
2021	2,567	28	2,595
2022	2,568	28	2,596
Thereafter	39,927	85	40,012
	$51,723	$1,138	$52,861

Approximately 90 miles of Partnership's pipeline system is located within the boundaries of the Fort Peck Indian Reservation in Montana. The Partnership 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, the Partnership 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.

6. CREDIT FACILITIES AND LONG-TERM DEBT

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

(In thousands)	**2017**	2016
2011 Credit Agreement – average interest rate of 2.695% at December 31, 2017 due 2020	**$15,500**	181,500
2001 Senior Notes – 7.50%, due 2021	**250,000**	250,000
Unamortized debt discount	**(188)**	(230)
Unamortized debt expense	**(1,256)**	(1,725)
	$264,056	429,545

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 is generally used by the Partnership to finance 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.

On August 26, 2016, the $100 million 2009 Senior Notes matured and the repayment was financed through a $100 million draw on the Partnership's 2011 Credit Agreement, which brought the Partnership's outstanding borrowings under the 2011 Credit Agreement to $181.5 million.

On November 15, 2016, the Partnership entered into a $100 million 364-day Revolving Credit Agreement (364-day Credit Agreement) that expired on November 14, 2017, which utilized the same covenants as the 2011 Credit Agreement. As a result of the shared covenants, the 2011 Credit Agreement was amended for the second time to include the cross default with the 364-day Credit Agreement.

On September 1, 2017, the Partnership paid down the outstanding borrowings under the 2011 Credit Agreement from $181.5 million to $15.5 million. The $166 million payment was financed through contributions from partners of $83 million each. At the time of the payment on the 2011 Credit Agreement, the Partnership also terminated the 364-day Credit Agreement.

At December 31, 2017, the Partnership's outstanding borrowings under the 2011 Credit Agreement were $15.5 million, leaving $184.5 million available for future borrowings. 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 on its credit rating and on the unused principal amount of the commitment of $200 million under the 2011 Credit Agreement.

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.

At December 31, 2017, the Partnership was in compliance with all of its financial covenants.

Aggregate required repayment of long-term debt for the next five years is $265.5 million, with $15.5 million due in 2020 and $250 million due in 2021. There are no required repayment obligations for 2018, 2019, or 2022.

7. 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, 2017, the Partnership reclassified the below amounts from AOCL into earnings for these terminated derivatives.

Net Loss Reclassified from AOCL into Income (Effective Portion)		Years Ended December 31,		
(In thousands)	Statements of Income Caption	**2017**	2016	2015
Cash flow hedges	Interest expense	**$(285)**	(264)	(245)

At December 31, 2017 and 2016, AOCL was $1.3 million and $1.5 million, respectively, and is being amortized through 2021 as noted above. The Partnership expects to reclassify $0.3 million from AOCL as an increase to interest expense in 2018. The Partnership had no other derivative instruments during the period ended December 31, 2017.

8. 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, 2017 and 2016. 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.

	2017		2016	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial asset:				
Cash and cash equivalents	**$14,010**	**14,010**	13,535	13,535
Financial liability:				
Long-term debt	**265,500**	**294,154**	431,500	464,357

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 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, 2017 and 2016:

	2017		2016	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Natural gas imbalance asset	**$815**	**815**	44	44
Related party natural gas imbalance asset	**—**	**—**	951	951
Natural gas imbalance liability	**1,232**	**1,232**	2,484	2,484
Related party natural gas imbalance liability	**$308**	**308**	—	—

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.

9. TRANSACTIONS WITH MAJOR CUSTOMERS

For the year ended December 31, 2017, shippers providing significant operating revenues to the Partnership were Sequent Energy Management, ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), a subsidiary of ONEOK, BP Canada, and Tenaska Marketing Ventures with revenues of $34.6 million, $31.5 million, $30.2 million, and $28.7 million, respectively. At December 31, 2017, Tenaska Marketing Ventures, EDF Trading North America, ONEOK Rockies and Sequent Energy Management, owed the Partnership approximately $3.1 million, $3.1 million, $2.8 million and $2.7 million, respectively, which is greater than 10 percent of the Partnership's trade accounts receivable.

For the year ended December 31, 2016, shippers providing significant operating revenues to the Partnership were BP Canada, Tenaska Marketing Ventures, ONEOK Rockies, and EDF Trading North America with revenues of $29.5 million, $28.5 million, $28.4 million and $27.9 million, respectively. At December 31, 2016, Sequent Energy Management, Tenaska Marketing Ventures, and ONEOK Rockies owed the Partnership approximately $3.2 million, $2.9 million, and $2.6 million, respectively, which is greater than 10 percent of the Partnership's trade accounts receivable.

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.

10. 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 capital, salaries, benefits and expenses of TransCanada and its affiliates attributable to the Partnership's operations. For the years ended December 31, 2017, 2016, and 2015, the Partnership's charges from TransCanada and its affiliates totaled approximately $43.3 million, $32.0 million, and $36.4 million, respectively. The impact of these charges on the Partnership's income was $31.3 million, $24.4 million, and $28.0 million, respectively. At December 31, 2017 and 2016, the Partnership owed $3.6 million and $3.5 million, respectively, to these affiliates classified to related party accounts on the balance sheets.

For the years ended December 31, 2017, 2016, and 2015, the Partnership had contracted firm capacity held by one customer affiliated with one of the Partnership's general partners. Revenues from ONEOK Rockies for 2017, 2016, and 2015 were $31.5 million, $28.4 million, and $22.6 million, respectively. At December 31, 2017 and 2016, the Partnership had outstanding receivables from ONEOK Rockies of $2.8 million and $2.6 million, respectively.

11. 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. Effective April 1, 2016, the Partnership transitioned from quarterly distributions paid approximately one month following the end of the quarter to monthly distributions paid approximately one month following the end of each reported month.

For the years ended December 31, 2017, 2016, and 2015, the Partnership paid distributions to its general partners of $165.9 million, $209.8 million, and $182.2 million, respectively. In 2017, the Partnership received contributions from its partners of $166 million, $83 million each, which was used as a payment on the 2011 Credit Agreement.

12. SUBSEQUENT EVENTS

On January 8, 2018, the Management Committee of the Partnership declared a cash distribution in the amount of $14.8 million. The distribution was paid on January 31, 2018.

On February 14, 2018, the Management Committee of the Partnership declared a cash distribution in the amount of $17.1 million. The distribution will be paid on February 28, 2018.

Subsequent events have been assessed through February 16, 2018, 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

Financial Statements

December 31, 2017 and 2016

(With Independent Auditors' Report Thereon)

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, 2017 and 2016, 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, 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 16, 2018

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
BALANCE SHEETS

December 31, 2017 and 2016 (In Thousands)	**2017**	2016
Assets		
Current assets:		
Cash and cash equivalents	**$ 44**	39
Demand loan receivable from affiliate	**64,040**	27,144
Accounts receivable:		
Trade	**7,409**	7,351
Affiliates	**20,236**	19,185
Materials and supplies	**9,689**	10,150
Other	**5,356**	2,287
Total current assets	**106,774**	66,156
Property, plant, and equipment:		
Property, plant, and equipment	**2,105,808**	2,087,281
Construction work in progress	**1,330**	5,853
	2,107,138	2,093,134
Less accumulated depreciation and amortization	**(1,406,348)**	(1,379,043)
Total property, plant, and equipment, net	**700,790**	714,091
Total assets	**$ 807,564**	780,247
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable:		
Trade	**$ 8,095**	11,772
Affiliates	**4,919**	3,744
Provision for revenue sharing refund *(Note 2(j))*	**39,601**	7,200
Provision for rate refund (*Note 5)*	**7,972**	–
Current maturities of long-term debt	**19,000**	19,000
Taxes payable (other than income)	**7,916**	7,990
Accrued interest	**6,240**	6,543
Other current liabilities	**–**	2,767
Total current liabilities	**93,743**	59,016
Long-term debt, net of current maturities	**239,753**	258,712
Regulatory liabilities	**744**	–
Other noncurrent liabilities	**212**	226
Partners' capital	**473,112**	462,293
Total liabilities and partners' capital	**$ 807,564**	780,247

See accompanying notes to financial statements.

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

Years ended December 31, 2017, 2016, and 2015 (In Thousands)	**2017**	2016	2015
Operating revenues, *net (Note 2(j))*	**$181,487**	179,133	176,901
Operating expenses:			
Operation and maintenance	**54,885**	58,048	49,222
Depreciation and amortization	**29,474**	27,911	27,756
Taxes, other than income	**10,830**	10,872	10,637
Total operating expenses	**95,189**	96,831	87,615
Operating income	**86,298**	82,302	89,286
Other income, net	**480**	521	1,511
Interest and debt expense	**(20,831)**	(22,295)	(23,946)
Affiliated interest income	**372**	114	54
Net income	**$ 66,319**	60,642	66,905
Partners' capital:			
Balance at beginning of year	**$462,293**	484,951	460,446
Net income	**66,319**	60,642	66,905
Distributions to partners	**(74,500)**	(102,300)	(61,400)
Contributions from partners	**19,000**	19,000	19,000
Balance at end of year	**$473,112**	462,293	484,951

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF CASH FLOWS

Years ended December 31, 2017, 2016, and 2015 (In Thousands)	**2017**	2016	2015
Cash flows from operating activities:			
Net income	**$ 66,319**	60,642	66,905
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**29,474**	27,911	27,756
Allowance for funds used during construction, equity	**(116)**	(263)	(78)
Amortization of debt issuance cost, reported as part of interest expense	**41**	82	46
Asset and liability changes:			
Accounts receivable	**(1,109)**	(4,437)	2,191
Other current assets	**(2,608)**	321	(1,107)
Accounts payable	**(1,792)**	1,043	(941)
Provision for revenue sharing refund	**32,401**	5,300	1,900
Provision for rate refund	**7,972**	–	–
Other current liabilities	**(3,144)**	2,712	(9,579)
Noncurrent liabilities	**(14)**	(9)	(10)
Net cash provided by operating activities	**127,424**	93,302	87,083
Cash flows from (used in) investing activities:			
Additions to property, plant, and equipment	**(13,814)**	(14,885)	(7,265)
Net change in demand loan receivable from affiliate	**(36,896)**	23,928	(20,670)
Other	**(2,209)**	(54)	2,263
Net cash provided by (used in) investing activities	**(52,919)**	8,989	(25,672)
Cash flows used in financing activities:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(19,000)
Distributions to partners	**(74,500)**	(102,300)	(61,400)
Contributions from partners	**19,000**	19,000	19,000
Net cash used in financing activities	**(74,500)**	(102,300)	(61,400)
Net change in cash and cash equivalents	**5**	(9)	11
Cash and cash equivalents at beginning of year	**39**	48	37
Cash and cash equivalents at end of year	**$ 44**	39	48
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$ 20,791**	22,529	24,153
Accruals for property, plant and equipment	**$ 1,497**	–	340

See accompanying notes to financial statements.

(1) DESCRIPTION OF BUSINESS

Great Lakes Gas Transmission Limited Partnership (the Partnership) is a Delaware limited partnership that owns 2,115 miles of natural gas pipeline system, which 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, 2017 and 2016 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's parent, TC PipeLines, LP is also an indirect subsidiary of TransCanada.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Partnership's financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP).

(b) Use of Estimates

The preparation of the financial statements in accordance with 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.

(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) 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, 2017 and 2016:

	December 31,			Remaining recovery/ settlement period
		2017	2016	
		(In thousands)		(Years)
Regulatory Assets				
Volumetric fuel tracker		2,787	–	(a)
Less: Current portion included in Other		2,787	–	
	$	–	–	
Regulatory Liabilities				
Negative salvage	$	744	–	(b)
Volumetric fuel tracker		–	2,767	(a)
		–	2,767	
Less: Current portion included in Other		–	2,767	
	$	744	–	

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

(b) 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 4(b)).

(e) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest, except for those receivables subject to late charges. The Partnership maintains an allowance for doubtful accounts for estimated losses on accounts receivable, 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. There were no accounts charged to the allowance in 2017 and 2016.

(f) Natural Gas Imbalances

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

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

(g) Material and Supplies

The Partnership's inventories primarily consist of materials and supplies and are carried at lower of weighted average cost or market.

(h) Property, Plant, and Equipment

Property, plant, and equipment are recorded at their original cost of construction. For assets the Partnership constructs, direct costs are capitalized, such as labor and materials, and indirect costs, such as overhead and interest 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. A substantial portion of the Partnership's principal operating assets are being depreciated at an annual rate of 1.27%. The remaining assets are depreciated at annual rates ranging from 2.33% to 20.00%. Using these rates, the remaining depreciable life of these assets ranges from 4 to 44 years.

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

The Partnership capitalizes a carrying cost on funds invested in the construction of long-lived assets. This carrying cost includes a return on the investment financed by debt and equity allowance for funds used during construction (AFUDC). AFUDC is calculated based on the Partnership's average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of the asset on the balance sheets. Capitalized AFUDC debt amounts are included as a reduction of interest and debt expense in the statements of income.

(i) Long-Lived Assets

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

(j) Revenue Recognition

The Partnership's revenues are primarily generated from transportation services. Revenues for all services are based on the quantity of gas delivered or subscribed at a price specified in the contract. For the Partnership's transportation services, reservation revenues are recognized on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. For interruptible or volumetric-based services, the Partnership records revenues when physical deliveries of natural gas are made at the agreed-upon delivery point. The Partnership does not take ownership of the gas that it transports. The Partnership is subject to FERC regulations, and as a result, revenues the Partnership collects may be subject to refund in a rate proceeding. The Partnership establishes provision for these potential refunds. As of December 31, 2017 and 2016, the Partnership has not collected and recognized any revenue that is subject to potential refund.

The Partnership operates under a FERC approved 2013 rate settlement that includes a revenue sharing mechanism that requires the Partnership share with its shippers 50% of any qualifying revenues earned during the year that result in a return on equity (ROE) above 13.25%. Qualifying revenues above a 20% ROE are returned to shippers at 100%. The Partnership establishes a provision for this revenue sharing as an offset against revenue in the income statement and recognizes an estimated refund liability classified as provision for revenue sharing refund in the balance sheet. Accordingly, the revenues presented in the statement of income for the years ended December 31, 2017, 2016 and 2015 were net of $39.6 million, $7.8 million and $1.9 million estimated revenue sharing provision, respectively. During 2016, the calculation of the 2015 refund was finalized and a total of $2.5 million was refunded to qualifying shippers in November 2016. During 2017, the calculation of the 2016 refund was finalized and a total of $6.9 million was refunded to qualifying shippers in June 2017. The Partnership expects that a significant portion of the 2017 estimated revenue sharing provision will be refunded to its affiliates which is consistent with prior years.

(k) 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, 2017 and 2016. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

Other Contingencies

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

(l) Income Taxes

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

(m) Debt Issuance costs

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

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

Debt issuance costs are presented in the balance sheet as a direct deduction from the carrying amount of debt liabilities, consistent with debt discount or premiums. In addition, amortization of debt issuance costs, premiums, and discounts are reported as part of interest expense.

(3) ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2017

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The new guidance specifies that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance was effective January 1, 2017, was applied prospectively and did not have a material impact on the Partnership's consolidated balance sheet.

Future Accounting Changes

Revenue from Contracts with Customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. Current guidance allows for revenue recognition when certain criteria are met. The new guidance requires that an entity recognizes revenue with a five step model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which the company expects to be entitled, during the term of the contract, in exchange for those goods or services. The Partnership will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. The Partnership will adopt the guidance using the modified retrospective approach with the cumulative-effect of the adjustment recognized at the date of adoption, subject to allowable and elected practical expedients.

The Partnership has identified all existing customer contracts that are within the scope of the new guidance. The Partnership has completed its analysis and has not identified any material differences in the amount and timing of revenue recognition. The Partnership will not require a cumulative-effect adjustment to opening partners' equity on January 1, 2018.

Although revenues will not be materially impacted by the new guidance, the Partnership will be required to add significant disclosures based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating when and how revenue is recognized and information related to contract assets and deferred revenues. In addition, the new guidance requires that the Partnership's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenue and cash flows generated from contracts with customers. The Partnership has addressed system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease requiring the customer to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset in order for the arrangement to qualify as a lease. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

The new guidance is effective on January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership is continuing to identify and analyze existing lease agreements to determine the effect of adoption of the new guidance on its consolidated financial statements. The Partnership is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance. The Partnership continues to monitor and analyze additional guidance and clarification provided by FASB.

(4) TAX REFORM IMPACT

On December 22, 2017, the President of the United States signed into law H.R. 1 (the Tax Cuts and Jobs Act). This legislation provides for major changes to U.S. corporate federal tax law, including a reduction in the U.S. corporate tax rate to 21 percent from 35 percent. As a limited partnership, the Partnership is a non-taxable pass through entity and income taxes owed as a result of the Partnership's earnings are the responsibility of each partner, therefore no amounts have been recorded in the Partnership's financial statements as a result of the Tax Cuts and Jobs Act.

The Partnership is regulated by the FERC, which approves its rates, the most recent of which were established through a negotiated settlement that did not ascribe any specific cost of service elements to income taxes. While the FERC also evaluates the Partnership's rate of return on an overall cost-of-service basis, they provide for a recovery of the Partnership's ultimate taxable owners' income tax expense and related balance sheet accounts as components of the maximum recourse rates that may be charged to customers. As a non-taxable pass through entity, the Partnership does not recognize income tax expense nor has it established deferred income tax assets or liabilities. Income tax related expenses, benefits, assets, and liabilities attributable to regulated operations are the responsibility of the ultimate taxable owners of the Partnership and any adjustment to income tax accounts following the Tax Cuts and Jobs Act must be evaluated by those owners.

The Partnership cannot predict the impact; if any, of lower U.S. corporate tax rates on its future revenues. If in the future the FERC were to require a change in the Partnership's maximum recourse rates related to the change in U.S. corporate tax rate, the Partnership expects rates would be revised through future rate proceedings or other regulatory action.

At December 31, 2017, the Partnership considers its assessment of the impact of the Tax Cuts and Jobs Act to be its best interpretation of available guidance. Should additional guidance on the impact of the Tax Cuts and Jobs Act on non-taxable partnerships be provided by regulatory, tax and accounting authorities or other sources in the future, the Partnership will review the approach used and adjust as appropriate.

(5) 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 (Essar Minnesota) and certain Foreign 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. 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 the Partnership. On September 20, 2015, Essar appealed the decision to the United States Court of Appeals for the Eighth Circuit (Eighth 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 Eighth Circuit heard the appeal on October 20, 2016. A decision on the appeal was received in December 2016 and the Eighth Circuit vacated the Partnership' judgment against Essar finding that there was no federal jurisdiction. The Partnership filed a Request for Rehearing with the Eighth Circuit and it was denied in January 2017. Before the Circuit Court issued its decision, Essar Minnesota filed for bankruptcy in July 2016. The Foreign Essar Affiliates have not filed for bankruptcy. Following the Circuit Court's decision, the performance bond was released into the bankruptcy court proceedings. The Partnership filed a claim against Essar Minnesota in the bankruptcy court and its case against the Foreign Essar Affiliates in Minnesota state court remains pending. In April 2017, after The Partnership agreement with creditors on an allowed claim, the bankruptcy court approved the Partnership's claim in the amount of $31.5 million. On May 20, 2017, the federal district court awarded Essar Minnesota approximately $1.2 million for costs, including recovery of the performance bond premium, to be paid by the Partnership. The Partnership filed a motion with the bankruptcy court to offset the $1.2 million award of costs against its claim against Essar Minnesota in the bankruptcy proceeding but was unsuccessful. As a result, in November 2017, the Partnership accrued the $1.2 million costs in relationship to the claim.

The Partnership is unable to estimate the timing or the extent to which its claim will be recoverable in the bankruptcy proceedings; therefore, did not recognize any accrual for its outstanding legal matters at December 31, 2017.

(b) Regulatory Matters

ANR contracts

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.

2017 Rate case

On October 30, 2017, the Partnership filed a rate settlement with FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018 (2017 Settlement). The 2017 Settlement, if approved by FERC, will decrease the Partnership's maximum transportation rates by 27 percent beginning October 1, 2017. The 2017 Settlement does not contain any moratorium and the Partnership will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022.

Under the terms of the 2017 Settlement, the revenue sharing mechanism was eliminated (refer to Note 2(j)). The Partnership's annual depreciation rates remain materially unchanged but for regulatory purposes, the Partnership shall reflect a negative salvage at an annual rate of 0.15% of transmission plant. Additionally, beginning October 1, 2017, the Partnership was still charging customers rates in effect prior to the 2017 Settlement but was only recognizing revenue up to the amount of the new rates in the 2017 Settlement. The difference between these two amounts was recognized as a provision for rate refund on the balance sheet.

(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 is currently negotiating to renew these agreements.

(6) LONG-TERM DEBT

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

(In thousands)	**2017**	2016
6.73% series Senior Notes due 2016 to 2018	**$9,000**	18,000
9.09% series Senior Notes due 2016 to 2021	**40,000**	50,000
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
	259,000	278,000
Less current maturities	**19,000**	19,000
Total long-term debt less current maturities	**$240,000**	259,000

The aggregate annual required repayment of long-term debt is $19.0 million for 2018, $21.0 million for each year 2019 through 2020, and $31.0 million for 2021. Aggregate required repayments of long-term debt thereafter total $167.0 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 $139.5 million of partners' capital was restricted as to distributions as of December 31, 2017. As of December 31, 2017 Partnership was in compliance with all of its financial covenants.

(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, 2017 and 2016. 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.

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. At December 31, 2017 the carrying value of the long term debt is $259 million and the fair value amount is $335 million. At December 31, 2016 the carrying value of the long term debt was $278 million and the fair value amount was $354 million.

(c) Other Recurring Fair Value of Financial Instruments

The following table presents the carrying amounts which equal fair values of other items measured and recorded at fair value on a recurring basis as of December 31, 2017 and 2016:

	2017		2016	
(In thousands)	Carrying amount	Fair value	Carrying amount	Fair value
Affiliate natural gas imbalance asset	**$325**	**325**	4,366	4,366
Natural gas imbalance asset	**$343**	**343**	322	322
Affiliate natural gas imbalance liability	**$1,796**	**1,796**	12	12
Natural gas imbalance liability	**$3,089**	**3,089**	3,049	3,049

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.

(8) 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, 2017 and 2016, the Partnership had a demand loan receivable from TransCanada of $64.0 million and $27.1 million, respectively.

(b) Affiliate Revenues and Expenses

The Partnership earns significant transportation revenues from TransCanada and its affiliates under contracts, which provide for negotiated, 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 both short-haul and long-haul transportation services

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 years ended December 31:

(In thousands)	**2017**	2016	2015
Transportation revenues from affiliates	**$130,165**	127,932	125,296
Rental revenue from affiliates	**1,556**	1,680	1,803
Costs charged from affiliates	**35,381**	30,100	30,022

* Transportation revenues from affiliates represent the amount recognized by the Partnership before any allowance on revenue sharing and provision for rate refund, which represent 57%, 68% and 70%, of the Partnership's total revenues for the year ended December 31, 2017, 2016 and 2015, respectively.

On April 24, 2017, Great Lakes reached an agreement on the terms of a new long-term transportation capacity contract with its affiliate, TransCanada. The contract, which was subject to Canada's National Energy Board (NEB) approval, is for a term of 10 years and allows TransCanada the ability to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system from the Manitoba/U.S. border to the U.S. border near Dawn Ontario. On September 21, 2017, TransCanada received approval from the NEB and as a result, this contract commenced on November 1, 2017. The Partnership recognized $13.0 million in transportation revenue related to this contract in 2017. This contract contains volume reduction options up to full contract quantity beginning in year three.

(9) 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 10, 2018, the Management Committee of the Partnership declared a cash distribution in the amount of $19.5 million to the partners. The distribution was paid on February 1, 2018.

(10) SUBSEQUENT EVENTS

Subsequent events have been assessed through February 16, 2018, 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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Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

December 31 (millions of dollars)	**2017**	2016[(a)]	2015[(a)]	2014[(a)]	2013[(a)(b)]
Earnings					
Net income before adjustment for income from equity investees	**139**	166	160	153	154
Fixed charges	**84**	73	68	62	57
Distributed income (loss) of equity investees[(c)]	**124**	97	(102)	88	67
Non-controlling interests of subsidiaries that have not incurred fixed charges	**–**	–	–	(10)	(14)
Total Earnings	**347**	336	126	293	264
Fixed Charges					
Interest expensed and capitalized	**83**	69	64	56	50
Amortization of other assets	**1**	4	4	6	7
Total Fixed Charges	**84**	73	68	62	57
Ratio of Earnings/Fixed Charges	**4.13X**	4.60X	1.85x	4.73x	4.63x

(a) Recast information to consolidate PNGTS for all periods presented as a result of an additional 11.81 percent in PNGTS that was acquired from a subsidiary of TransCanada on June 1, 2017. Prior to this transaction, the Partnership owned a 49.9 percent interest in PNGTS that was acquired from TransCanada on January 1, 2016. Please read Note 2 – Significant Accounting Policies – Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV,Item 15. "Exhibits and Financial Statement Schedules".

(b) Recast information to consolidate GTN and Bison for all periods presented as a result of additional 45 percent membership interests in each of GTN and Bison that were acquired from subsidiaries of TransCanada in 2013 resulting in a 70 percent ownership in each. Please read Note 2, Significant Accounting Policies- Basis of Presentation section of the Notes to the Consolidated Financial Statements included in Part IV,Item 15. "Exhibits and Financial Statement Schedules".

(c) Distributed income of equity investees for 2015 includes $199 million impairment charge on our Investment in Great Lakes. Please read Note 5-Equity Investments, Notes to the Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules".

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Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

Exhibit 21.1

SUBSIDIARIES OF THE REGISTRANT

1. The Registrant holds a 98.9899 percent limited partner interest in TC GL Intermediate Limited Partnership, a Delaware limited partnership.

2. Through its interest in TC GL Intermediate Limited Partnership, the Registrant holds a 46.45 percent general partner interest in Great Lakes Gas Transmission Limited Partnership, a Delaware limited partnership.

3. The Registrant holds a 98.9899 percent limited partner interest in TC PipeLines Intermediate Limited Partnership, a Delaware limited partnership.

4. Through its interest in TC PipeLines Intermediate Limited Partnership, the Registrant holds a 50 percent general partner interest in Northern Border Pipeline Company, a Texas general partnership.

5. Through its interest in TC PipeLines Intermediate Limited Partnership, the Registrant wholly-owns Gas Transmission Northwest LLC, a Delaware limited liability company.

6. Through its interest in TC PipeLines Intermediate Limited Partnership, the Registrant wholly-owns Bison Pipeline LLC, a Delaware limited liability company.

7. Through its interest in TC PipeLines Intermediate Limited Partnership, the Registrant wholly-owns North Baja Pipeline, LLC, a Delaware limited liability company.

8. The Registrant holds a 98.9899 percent limited partner interest in TC Tuscarora Intermediate Limited Partnership, a Delaware limited partnership.

9. Through its interest in TC Tuscarora Intermediate Limited Partnership, the Registrant wholly-owns TC Pipelines Tuscarora LLC, a Delaware limited liability company.

10. Through its interest in TC Tuscarora Intermediate Limited Partnership and TC Pipelines Tuscarora LLC, the Registrant wholly-owns Tuscarora Gas Transmission Company, a Nevada general partnership.

11. Through its interest in TC PipeLines Intermediate Limited Partnership, the Registrant holds a 49.9 percent general partner interest in Portland Natural Gas Transmission System, a Maine general partnership.

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Exhibit 21.1

SUBSIDIARIES OF THE REGISTRANT

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We consent to the incorporation by reference in the registration statements (Nos. 333-211907 and 333-213024) on Form S-3 of TC PipeLines, LP of our report dated February 26, 2018, with respect to the consolidated balance sheets of TC PipeLines, LP as of December 31, 2017 and 2016, and the related consolidated 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, 2017, and the related notes (collectively, the "consolidated financial statements"), and the effectiveness of internal control over financial reporting as of December 31, 2017, which report appears in the December 31, 2017 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Houston, Texas
February 26, 2018

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We consent to the incorporation by reference in the registration statements (Nos. 333-211907 and 333-213024) on Form S-3 of TC PipeLines, LP of our report dated February 16, 2018, with respect to the balance sheets of Northern Border Pipeline Company as of December 31, 2017 and 2016, 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, 2017, and the related notes (collectively, the "financial statements"), which report appears in the December 31, 2017 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Houston, Texas
February 26, 2018

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Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We consent to the incorporation by reference in the registration statements (Nos. 333-211907 and 333-213024) on Form S-3 of TC PipeLines, LP of our report dated February 16, 2018, with respect to the balance sheets of Great Lakes Gas Transmission Limited Partnership as of December 31, 2017 and 2016, 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, 2017, and the related notes (collectively, the "financial statements"), which report appears in the December 31, 2017 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Houston, Texas
February 26, 2018

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Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Exhibit 31.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER

I, Brandon Anderson, certify that:

1. I have reviewed this annual report on Form 10-K of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 26, 2018

/s/ BRANDON ANDERSON

Brandon Anderson
Principal Executive Officer and President
TC PipeLines GP, Inc., as General Partner of
TC PipeLines, LP

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Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

Exhibit 31.2

**CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER**

I, Nathaniel A. Brown, certify that:

1. I have reviewed this annual report on Form 10-K of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 26, 2018

/s/ NATHANIEL A. BROWN

Nathaniel A. Brown
Principal Financial Officer and Controller
TC PipeLines GP, Inc., as General Partner of
TC Pipelines, LP

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Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

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Exhibit 32.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER

I, Brandon Anderson, Principal Executive Officer and President of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Annual Report on Form 10-K for the period ended December 31, 2017 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: February 26, 2018

/s/ BRANDON ANDERSON

Brandon Anderson
Principal Executive Officer and President
TC PipeLines GP, Inc., as General Partner of
TC PipeLines, LP

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Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

Exhibit 32.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER

I, Nathaniel A. Brown, Principal Financial Officer and Controller of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Annual Report on Form 10-K for the period ended December 31, 2017 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: February 26, 2018

/s/ NATHANIEL A. BROWN

Nathaniel A. Brown
Principal Financial Officer and Controller
TC PipeLines GP, Inc., as General Partner of
TC PipeLines, LP

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Exhibit 32.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER