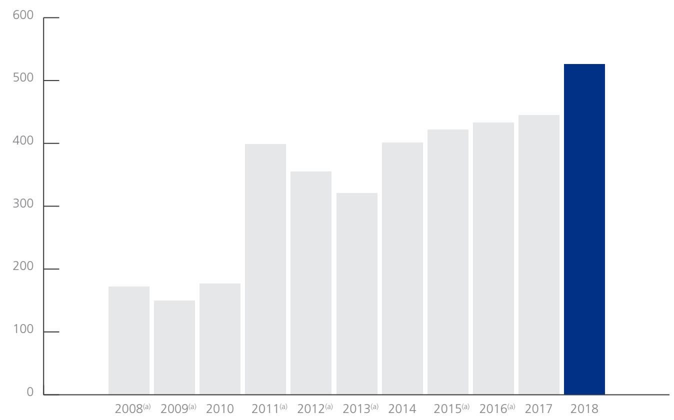
TC PipeLines, LP

ANNUAL REPORT 2018

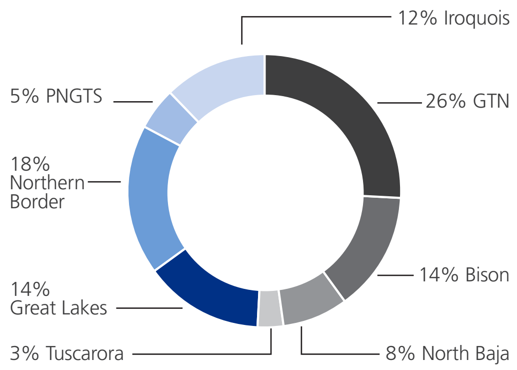
Financial Highlights

ADJUSTED EARNINGS BEFORE INTEREST, TAX, DEPRECIATION AND AMORTIZATION (ADJUSTED EBITDA)



(a) Recast information

2018 DISTRIBUTABLE CASH FLOW



Year Ended December 31 *(millions of dollars, except unit amounts)*	2018	2017	2016	2015	2014
Cash Flow					
Distributable cash flow (1)	391	310	313(4)	290(4)	255(4)
Cash distributions paid	218	284	250	228	212
Class B Distributions paid	15	22	12	-	-
Income Statement					
Net income (loss) attributable to controlling interests	(182)	252	248(4)	37(4)	195(4)
Adjusted earnings (1)	317	252	248(4)	236(4)	195(4)
EBITDA (1)	27	445	433(4)	223(4)	401(4)
Adjusted EBITDA (1)	526	445	433(4)	422(4)	401(4)
Balance Sheet					
Total assets (2)	2,899	3,559	3,354(4)	3,459(4)	3,343
Long-term debt (2) (including current maturities)	2,118	2,415	1,920(4)	1,980(4)	1,689
Partners' equity	699	1,068	1,272(4)	1,391(4)	1,818(4)
Common Unit Statistics (per unit)					
Cash distributions paid	2.95	3.88	3.66	3.46	3.30
Net income (loss) per common unit – basic and diluted	(2.68)	3.16	3.21	(0.03)	2.67
Adjusted earnings per common unit – basic and diluted (1)	4.18	3.16	3.21	3.03	2.67
Common Units Outstanding (millions)					
Units issued (3)	0.7	3.2	3.1	0.7	1.3
Weighted average for the year (3)	71.3	69.2	65.7	63.9	62.7
End of year (3)	71.3	70.6	67.4	64.3	63.6

(1) Distributable cash flow, EBITDA, adjusted EBITDA, adjusted earnings and adjusted earnings per common unit are non-GAAP measures. Non-GAAP measures do not have any standardized meaning prescribed by U.S. generally accepted accounting principles (GAAP). For more information on non-GAAP financial measures see item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K for the year ended December 31, 2018, filed with the Securities Exchange Commission (SEC).
(2) As a result of the application of 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.
(3) In 2014, the Partnership launched its ATM program. Please read Note 11 – Partners' Equity in Notes to Consolidated Financial Statements included in Part IV, Item 15. "Exhibits and Financial Statement Schedules".
(4) 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".

This material contains forward-looking statements relating to expectations, plans or prospects for TC PipeLines, LP. These statements are based upon the current expectations and beliefs of management and are subject to certain risks and uncertainties, including market conditions and other factors beyond the Partnership's control. Important factors that could cause actual results to differ materially from those described in the forward-looking statements herein are found in TC PipeLines, LP's Forms 10-K and 10-Q as filed with the SEC.

Letter to Unitholders

The last year has been a challenging but productive time for TC PipeLines. Our competitively-priced transportation services were highly contracted and utilized by our customers to transport low-cost gas to numerous markets and we generated record revenues from our diverse portfolio of interstate pipelines. Nonetheless, the decision by our pipelines' regulator, the Federal Energy Regulatory Commission or "FERC", to revise some of its long-standing policies, including one that had allowed MLP pipelines to recover allowances for federal income tax in the rates they charge their customers (the "2018 FERC Actions"), cast TC PipeLines' future revenues from our assets into doubt and impacted our unit value in the MLP market. In response, our experienced regulatory team made submissions to FERC and developed a customer outreach and regulatory strategy for each of our pipeline assets that we believe has mitigated the impact of the 2018 FERC Actions down to about $30 million in annual EBITDA reduction starting in 2019.

Stable Distributions

Despite our best efforts, we did not deliver the type of distributions in 2018 that, you, our unitholders, were accustomed to, and that we expected to deliver to you. We believe that, with the 2018 FERC Actions behind us, and our financial metrics more in line with a self-funding business model, we will again be able to deliver stable distributions going forward. We have a clear business advantage in developing pipeline capacity additions and enhancements across our assets' existing broad geographic footprint and we are seeking organic growth opportunities that fit the low-risk, reliable value proposition that TC PipeLines has stood for over the past 20 years.

Near-Term Growth Opportunities

The North American gas market outlook continues to unfold as a story of plentiful, low cost supply in search of connection to growing market demand. The New England and Atlantic Canada markets are experiencing a supply gap due to the rapid decline in off-shore production and LNG import activity, creating multiple opportunities for growth at PNGTS. PNGTS is half way through implementing its Portland XPress (PXP) project which has re-contracted this asset for 20 years and is set to increase its historical capacity by 25 percent in three phases between 2018 and 2020. Our success on PXP has sparked further market interest, resulting in PNGTS signing precedent agreements to proceed with a second expansion project on its system, Westbrook XPress, subject to customary conditions precedent and approvals. Westbrook XPress would, once completed, further expand this asset's firm capability by another 100-140,000 Dth/day in the 2019-2021 timeframe, effectively doubling the size of this asset over four years.

The Westbrook project entails compressor additions and modifications at an existing compressor station, a relatively low-risk development with a modest social and environmental impact and can be funded at the asset level.

Nathan Brown,
President
TC PipeLines GP, Inc.

This is one example of how we are positioning ourselves to deliver maximum long-term value by pursuing a targeted growth strategy that maximizes our competitive advantages while living within our means. We believe the financial strength and flexibility we have built up will enable us to self-fund these near-term growth opportunities without needing to access the equity capital markets.

Portfolio Performance

Our 2018 financial highlights are summarized as follows:

- Generated adjusted earnings of $317 million and adjusted EBITDA of $526 million
- Paid cash distributions of $218 million to the common unitholders and the General Partner; declared cash distribution of $2.60 per common unit or $0.65 per quarter
- Generated distributable cash flow of $391 million
- Reduced long-term debt balance by $295 million
- Incurred a net loss attributable to controlling interests of $182 million after accounting for non-cash impairment charges on Bison and Tuscarora partially offset by Bison's contract buy-out proceeds recognized in revenue
- Commenced Phase 1 of Portland XPress expansion contracts on November 1, 2018
- Finalized regulatory approaches to the 2018 FERC Actions for all assets, and obtained FERC approvals where applicable
- Received approval from the FERC on GTN rate settlement on November 30, 2018
- Reached rate settlements on both Tuscarora and Iroquois with their respective customers and filed documents with FERC in January 2019

Looking forward, we will seek out new innovative business strategies to capture the maximum transportation value from our pipelines and optimize distributable cash flow and annual EBITDA. We will strive to replenish growth in our asset base with new development opportunities and capital additions that will provide stable cash distributions while maintaining a low-risk profile. At the same time, we will maintain financial discipline and promote a self-funded business model. Finally, and most importantly, we will prioritize safety and reliability across our operations.

Non-Cash Write-downs

At the end of 2018, two of Bison's customers elected to pay out the remaining terms of their firm transportation contracts, releasing Bison from providing further service and resulting in $97 million available to reduce debt and repay one of our term loans. As part of our annual impairment review and in accordance with our accounting policies, TC PipeLines reviewed the persistent market conditions that have made natural gas deliveries from the Rockies' Powder River basin uneconomic in competition with the very inexpensive gas currently being produced in the Bakken and WCSB for delivery into the Midwest, and considered Bison's ability to generate positive cash flow as it is currently configured post 2021. Given the current commercial circumstances, we have recorded a non-cash impairment charge on our Consolidated Statement of Operations, effectively writing down Bison to nominal value.

It should be noted that there will be no cash flow impact from this write-down, as it is purely an accounting adjustment. We remain committed to Bison which has generated steady returns over its life thus far, but which will soon need to find a new role to play in the dynamic north American energy transportation grid. TC PipeLines is exploring two development opportunities for this asset, including a potential gas-flow reversal project that would take some of the rapidly growing unconventional gas production from the Bakken and connect it into existing third-party pipelines with links into the Cheyenne supply hub. We are also exploring the option of converting the Bison pipeline to liquids service.

The annual accounting impairment review process also resulted in a goodwill write-down of the carrying value of our Tuscarora pipeline, mostly due to changes in valuation assumptions including its recent response to the 2018 FERC Actions.

Further Growth

Our largest assets, GTN, Northern Border and Great Lakes, continued to benefit from strong demand for their transportation services throughout 2018, underscoring the strength of the "supply-push" from both WCSB and Bakken production. In today's era of prolific gas supply with increased inter-basin competition and challenges facing greenfield projects, the cost-effective transportation provided by our network of pipelines has a competitive advantage that we believe will support further opportunities for investment along our footprint. We are exploring ways to optimize these assets through potential expansion projects or commercial, regulatory and operational changes in response to positive supply fundamentals. We are also working together with TransCanada to explore opportunities to facilitate further WCSB market penetration through potential integrated Canadian-U.S. system offerings to maximize economic access to market.

Delivering Value

The cornerstone of TC PipeLines' strategy is to deliver stable, long-term value to our unitholders through all phases of the economic cycle. This reflects the value of our high-quality, long-life asset footprint that has safely and reliably delivered energy to our customers throughout our 20-year history. Natural gas transportation service remains essential to a well-functioning economy and we are well positioned to continue to help fuel America.

As always, safe and reliable operations are a primary focus for TransCanada and we are committed to industry leading pipeline operations and safety practices.

Finally, we value our investment grade credit ratings and will continue to prudently fund our growth. Through careful stewardship of our assets and disciplined growth, we expect to pay steady distributions and deliver ongoing value to our unitholders.

Thank you for your continued investment.

Sincerely,

Nathan Brown
President, TC PipeLines GP, Inc.

Our Strategy

Our strategy is focused on generating long-term, steady and predictable distributions to our unitholders through investments in long-life critical energy infrastructure that provide safe, reliable delivery of energy to our customers. We are managed by our General Partner which is wholly owned by TransCanada Corporation who also operates our pipeline systems, apart from our investment in Iroquois and the joint facilities on PNGTS, both of which are jointly owned with a third party and operated by independent management.

Although historically viewed as an element of TransCanada's financing strategy, the regulatory challenges faced by the natural gas pipeline industry in 2018 negatively impacted the viability of our use as a cost competitive dropdown vehicle. Despite continued solid business fundamentals, the MLP space weathered a severe period of price erosion and yield expansion following actions taken by FERC last year and given our assets, we were particularly impacted. Going forward, notwithstanding our traditional source of expansion has been suspended, we continue to be optimistic about our future growth which is expected to come from organic opportunities across our portfolio of natural gas pipeline assets that economically and efficiently expand our existing infrastructure to meet evolving market requirements. We anticipate these future opportunities will enhance our cash flow and deliver value for our unitholders.

Reliable Energy

Our pipeline systems provide critical connections between growing supply basins and large demand regions in North America and are capable of transporting approximately 10.8 Bcf/d or 13 percent of average daily U.S. natural gas demand. Our customers are primarily large utilities, local distribution companies, major natural gas marketers and producers. These customers, and the markets they serve, count on us to provide safe and reliable delivery of natural gas. We operate primarily in the Western U.S., the Midwest and the Northeast and have a strong market position in these regions.

GTN is our largest pipeline investment and provides a key service delivering gas from Western Canada and the Rocky Mountains to local utilities and power generation facilities in the Pacific Northwest, California and Nevada. Northern Border is our next largest asset and provides a critical transportation route linking Canadian natural gas out of Western Canada, as well as U.S. gas out of the Bakken formation in North Dakota, with key markets in Minneapolis and the Chicago area. Iroquois maintains key market connections into New York City, serving regional LDCs and power plants in the Northeast. Our Great Lakes pipeline is utilized by the TransCanada Mainline and other shippers to provide service to natural gas producers seeking markets in the Midwest U.S. and central Canada and provides access to storage fields in Michigan and Southern Ontario which are vital to balancing supply and demand throughout the year as seasonal demands for natural gas fluctuate. Great Lakes is also an important regional supplier of gas to local utilities in the upper Midwest serving heating load areas in Michigan, Minnesota and Wisconsin in conjunction with its TransCanada affiliate, ANR Pipeline. PNGTS, North Baja and Tuscarora are smaller in size but are critical infrastructure in their local markets and are backed by long-term contracts with customers. PNGTS' efficient expandability is being accessed to serve market demand for natural gas transport into New England and Atlantic Canada as Eastern Canadian production declines and demand grows in these regions. Although our Bison pipeline earns contractual revenue, it is not being utilized due to changing natural gas flow dynamics in the Midwest and we are evaluating opportunities for this asset in the years ahead.

Highly Contracted Assets

Solid commercial and market fundamentals support our portfolio of natural gas pipeline assets. The majority of our cash flows are derived from long-term contracts underpinning our pipelines. In 2018, virtually all of our partnership cash flows were from long-term contracts where shippers pay us for transportation capacity regardless of the volume of gas they actually ship. In the West, the majority of GTN's capacity is under long-term contracts with some maturing as late as 2045, Tuscarora is fully contracted through 2020, and North Baja's contracts mature between 2022 and 2031. In the Midwest, Northern Border is fully contracted with revenues substantially supported by long-term contracts with recent contract extensions typically for terms of up to five years. Great Lakes sold out its winter capacity in 2018, and its long-term contract tenor is improving as it remains a critical transportation link between natural gas storage fields in Michigan and Southern Ontario and major population centers in Minnesota, Wisconsin and Michigan in coordination with its TransCanada affiliate, ANR Pipeline. Great Lakes also provides a critical connection to the attractive Dawn market for gas producers in Western Canada, as evidenced by its 10-year contract with TransCanada's Mainline that began in late 2017. In the Northeast, PNGTS is contracted through 2019 and has new contracts for part of its capacity that began in late 2017 and mature in 2032. In response to continued demand for service in the Northeast, two expansions are underway at PNGTS. These expansions will bring further diversity of supply to the New England market and effectively utilize all of its expanded capacity through to 2032. And we recently announced a second expansion project on PNGTS in response to continued demand for service in the Northeast. Iroquois is highly contracted in the near term with contracts that expire out to 2026.

Our Bison pipeline was fully contracted to January 2021. During the fourth quarter of 2018, however, two of Bison's four customers paid the lump sum present value of their future obligations to buy out their contracts. These customers represented just over 60 percent of Bison's contracted revenue. Following the buyouts, until expiry of its remaining contracts in January of 2021, Bison will be contracted to approximately 40 percent of its previous levels on a ship-or-pay basis. We continue to evaluate alternatives for this pipeline going forward given the changing natural gas transportation dynamics in the region.

The long-term contracted nature of our assets is further enhanced by the high quality, creditworthy nature of our customer base where just under 72 percent of our shippers are of investment grade status.

Delivering Value

Our solid financial position is reflected in our investment grade credit ratings from both Standard & Poor's and Moody's. Additionally, our lending group is strong and continues to be supportive.

Our assets delivered solid value in 2018. GTN continued to perform well with the sale of additional short and long-term contract volumes during the year. Demand in the West remains strong, and natural gas producers in the WCSB are eager to access this premium market, leading to additional contracting. Northern Border continues to generate solid results as a very competitive transportation path out of Western Canada. Great Lakes remains a critical delivery infrastructure system in the upper Midwest market serving heating loads in the winter and providing access to substantial storage in the summer. Iroquois has been a solid addition to our portfolio of assets and continues to generate additional equity earnings. The remainder of our assets performed well and in line with our expectations.

The earlier noted contract buyouts on our Bison pipeline prompted us to evaluate the ongoing carrying value of this asset on our balance sheet and we concluded that we cannot determine, with sufficient accuracy, the appropriate value of this pipeline under the current circumstances. Based on this uncertainty and other factors, we took an impairment charge in the fourth quarter. Marketing and redevelopment efforts are ongoing to replace the expiring Bison contracts as well as to develop an alternative use for this pipeline and maximize the ongoing cash flow stream.

After removing the impact of the one-time, non-cash impairment charges during the fourth quarter, together with the one-time lump sum cash payment related to the Bison contract buyouts, we generated $317 million in adjusted earnings and $391 million in distributable cash flow over the year. Despite these healthy operating results, the 2018 FERC tax-related regulatory actions are expected to have a significant impact on our business starting in 2019. In anticipation of this outcome, the Partnership reduced 2018 quarterly distributions by 35 percent to have sufficient cash to fund ongoing capital expenditures and enable future growth through the repayment of debt to levels that prudently manage our financial metrics.

Continuing changes in the New England and Canadian Maritime gas markets in which PNGTS operates are leading to future growth opportunities. Our Portland XPress Project is proceeding in response to the market's need for a timely and cost-effective increase in natural gas transportation service in the region and PNGTS is developing an additional expansion opportunity, the Westbrook XPress Project, which is similar in size and scope and responsive to ongoing market demand in the area.

Stable Rates

Notwithstanding the recent regulatory challenges faced by our industry in 2018, we believe our pipeline systems have responded in a prudent manner to resolve the uncertainty and restore stability in our business. We expect the regulated rates on our pipelines will continue to afford cash flow certainty and underpin the stable nature of our asset portfolio.

Our pipeline systems operate under long-term FERC-approved rates. To address the changes emanating from the FERC's actions in 2018, our GTN pipeline reached an uncontested settlement with its shippers which was approved by the FERC and under which there is no requirement to file for new rates until 2022. Great Lakes, Tuscarora and Northern Border each elected to make a limited Section 4 filing with FERC that included recourse rate reductions and the elimination of deferred income tax balances with no requirement to file for new rates until 2022 for Great Lakes, 2023 for Tuscarora and 2024 for Northern Border. North Baja similarly elected to make a limited Section 4 filing and reduce its recourse rates and eliminate its deferred income tax balances. North Baja operates primarily under long-term negotiated rates so this reduction is not expected to be material to its revenues and it has no requirement to file for new rates. PNGTS and Bison do not believe rate changes are required as a result of the FERC's actions in 2018 and have no requirement to file a new rate proceeding. Iroquois reached a settlement with its customers and has no requirement to file for new rates until 2023.

Evolving Natural Gas Industry

The natural gas industry continues to undergo changes as the market adjusts to increased natural gas supplies and production, the most impactful of which has been the growth in natural gas production in the Marcellus and Utica basins in the Northeast U.S. and in the WCSB in Western Canada. This growing production continues to impact historical transportation flows on natural gas pipelines. Concurrent with upstream developments on TransCanada's Mainline, Great Lakes entered into a long-term transportation agreement with TransCanada in late 2017 to transport 711,000 Dth/d of natural gas under a 10-year contract. This service commenced November 1, 2017 and is a testament to its value as a competitive path to move WCSB natural gas volumes to eastern markets. In the West, our GTN pipeline is experiencing increasing demand for its transportation service as upstream debottlenecking activities on TransCanada's NGTL system are allowing more gas to exit Canada and flow on GTN to West Coast markets. And in the Northeast, our PNGTS pipeline is in the midst of expanding its capacity with potential additional growth as natural gas demand continues to grow in that region and PNGTS is able to deliver economic expansion and deliverability in an area where infrastructure growth is challenging.

Increases in natural gas supply, along with lower natural gas prices, are expected to increase demand for natural gas as electrical generation and industrial sectors, as well as residential users, seek increased use of natural gas for their power and heating needs. North American natural gas production is expected to grow significantly between now and 2027 which will provide opportunities for infrastructure as increased gas flows move from production basins to market.

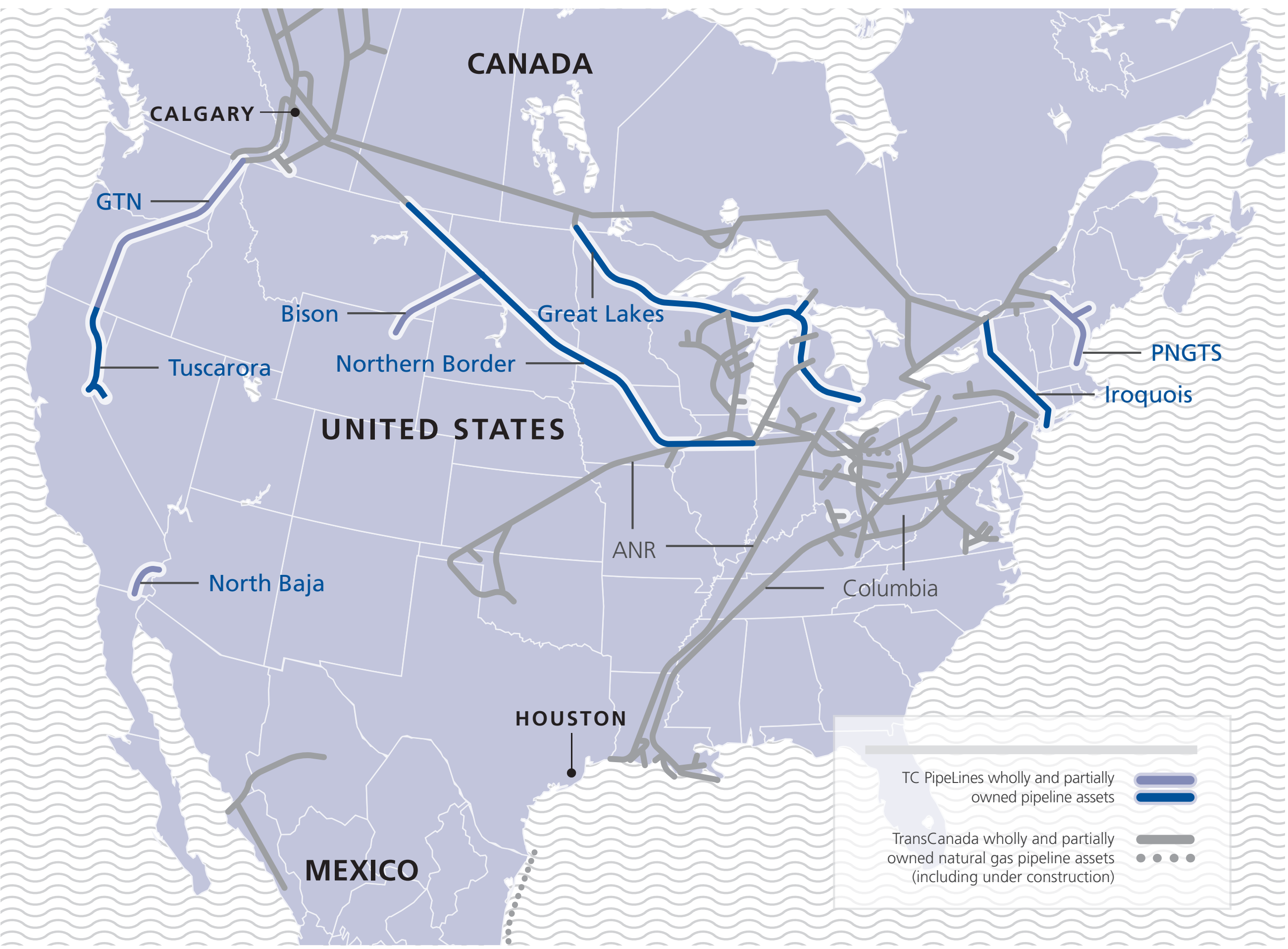
North America's gas infrastructure continues to provide safe, reliable and cost efficient gas delivery service to customers in all regions. And as the industry continues to evolve, we anticipate opportunities for expansion and growth. Eastern Canada's offshore production has declined and is in the process of being de-commissioned, driving market demand for new natural gas delivery paths into New England and Atlantic Canada.

Disciplined Growth

We are well positioned to capitalize on growth opportunities. We have repaid debt to prudent levels and have a healthy balance sheet. Our investment grade credit ratings are indicative of our solid business platform and provide a firm basis from which to grow our business.

We see solid potential for continued organic expansion projects on our existing pipeline systems and also continue to assess the potential for third party acquisitions. Our Portland XPress and Westbrook XPress Projects, which will almost double PNGTS' firm capacity, are examples of this organic growth in response to the market's growing need for natural gas transportation capacity in the New England area.

We continue to build a strong and diversified asset base of strategically located pipeline assets and believe that this strong foundation of reliable energy infrastructure will deliver unitholder value well into the future.



TC PIPELINES, LP

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

PART I

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

This report includes certain forward-looking statements. 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 Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act ("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;
- failure to comply with debt covenants, some of which are beyond our control;

- the ability to maintain secure operation of our information technology including management of cybersecurity threats, acts of terrorism and related distractions;
- the implementation of future accounting changes and ultimate outcome of 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, 2018, subsidiaries of TransCanada own approximately 24 percent of our common units, 100 percent of our Class B units, 100 percent of our incentive distribution rights (IDRs) and has 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 DEVELOPMENTS IN OUR BUSINESS

2017 Tax Act, 2018 FERC Actions and its impact on our business:

In December 2016, FERC issued 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 had been in effect since 2005. Docket No. PL17-1-000 was 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 an MLP 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.

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 including a reduction of the federal corporate income tax rate to 21 percent. Under the 2017 Tax Act, we continue to be a non-taxable limited partnership for federal income tax purposes and federal income taxes on our earnings are the responsibility of our partners. Therefore, no amounts have been recorded in the Partnership's financial statements with respect to federal income taxes as a result of the 2017 Tax Act.

On March 15, 2018, FERC issued the following: (1) Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) to address the treatment of income taxes for rate-making purposes for MLPs, (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact that the U.S. federal income tax rate reduction and the Revised Policy Statement could have on a pipeline's Return on Equity (ROE) assuming a single-issue adjustment to a pipeline's rates, and (3) a NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes (ADIT) and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement (Order on Rehearing) dismissing rehearing requests related to the Revised Policy Statement and (2) a final rule adopting and revising procedures from, and clarifying aspects of, the NOPR (Final Rule). On November 15, 2018, FERC issued a policy statement on the Accounting and Rate-making Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset (Excess ADIT Policy Statement) addressing certain issues raised in the NOI issued on March 15, 2018 (collectively, the "2018 FERC Actions"). Each of the 2018 FERC Actions is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates

The Revised Policy Statement changed FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement created a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance regarding ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity's income tax allowance should be eliminated from rates, it may also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as a refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on Tax Law Changes for Interstate Natural Gas Companies

The Final Rule established a schedule by which interstate pipelines must have either (i) filed a new uncontested rate settlement or (ii) filed a one-time report, FERC Form No. 501-G, that quantified the rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. Pipelines filing the one-time report had four options:

- Option 1: make a limited NGA Section 4 filing to reduce its rates by the reduction in its cost of service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guaranteed a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G showed the pipeline's estimated ROE as being 12 percent or less. Under the Final Rule and notwithstanding the Revised Policy Statement, a pipeline organized as an MLP is not required to eliminate its income tax allowance, but instead can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance, along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base used for rate-making purposes;
- Option 2: commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believed that using the limited Section 4 option would not result in just and reasonable rates. If the pipeline committed to file by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it did not believe the pipeline's rates must change; or

- Option 4: take no action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that had not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates
In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, was required by FERC related to the ADIT that were reserved in anticipation of being paid to the IRS, but which no longer accurately reflected the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated cost-of-service rates or earnings.

As noted above, FERC's Order on Rehearing provided guidance regarding ADIT for MLP-owned pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

As noted above, on November 15, 2018, FERC issued the Excess ADIT Policy Statement addressing certain (but not all) issues raised in this NOI. The Excess ADIT Policy Statement clarified the FERC accounts in which pipelines should record amortization of excess and/or deficient ADIT for accounting and rate-making purposes.

The Excess ADIT Policy Statement also addressed how to disclose reversals of ADIT account balances in FERC's annual financial report filings. The policy statement stated that, for those pipelines that continue to have an income tax allowance, excess/deficient ADIT associated with an asset that is sold or retired after December 31, 2017 must continue to be amortized in rates even after the sale or retirement of the asset.

Impact of the 2018 FERC Actions to the Partnership:
The 2018 FERC Actions directly addressed two components of our pipeline systems' cost-of-service based rates: the allowance for income taxes and the inclusion of ADIT in their rate base. The 2018 FERC Actions also noted that precise treatment of entities with more ambiguous ownership structures must be separately resolved on a case-by-case basis, such as those partially owned by corporations including Great Lakes, Northern Border, Iroquois and PNGTS. Additionally, any FERC-mandated rate reduction did not affect negotiated rate contracts.

Prior to the 2018 FERC Actions, none of the Partnership's pipeline systems had a requirement to file or adjust their rates earlier than 2022 as a result of their existing rate settlements. However, several of our pipeline systems accelerated such adjustments as a result of the 2018 FERC Actions as summarized in the table below.

	Form 501-G Filing Option	Impact on Maximum Rates	Moratorium, Mandatory Filing Requirements and Other Considerations
Great Lakes	Option 1; accepted by FERC	2.0% rate reduction effective February 1, 2019	No moratorium in effect; comeback provision with new rates to be effective by October 1, 2022
GTN	Settlement approved by FERC on November 30, 2018 eliminated the requirement to file Form 501-G	A refund of $10 million to its firm customers in 2018; 10.0% rate reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021; These reductions will replace the 8.3% rate reduction in 2020 agreed to as part of the last settlement in 2015	Moratorium on rate changes until December 31, 2021; comeback provision with new rates to be effective by January 1, 2022
Northern Border	Option 1; accepted by FERC	2.0% rate reduction effective February 1, 2019; proposed additional 2.0% rate reduction effective January 1, 2020	No moratorium in effect; comeback provision with new rates to be effective by July 1, 2024
Bison	Option 3	No rate changes proposed	No moratorium or comeback provisions
Iroquois	Option 3; subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 9, 2019.	Expected to reduce rates by the impact of the 2017 Tax Act as shown on Form 501-G	Likely to be reaffirmed with the settlement
PNGTS	Option 3; accepted by FERC	No rate changes	No moratorium or comeback provisions
North Baja	Option 1; accepted by FERC	10.8% rate reduction effective December 1, 2018	No moratorium or comeback provisions; approximately 90% of North Baja's contracts are negotiated; 10.8% reduction is on maximum rate contracts only
Tuscarora	Option 1; subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 29, 2019	Expected to be finalized with the settlement	Expected to be finalized with the settlement

As noted above, the Final Rule that allowed pipelines owned by MLPs and other pass through entities to remove the ADIT liability from their rate bases, and thus increase the net recoverable rate base, partially or in some cases wholly mitigated the loss of the tax allowance in cost-of-service based rates. Following the elimination of the tax allowance and the ADIT liability from rate base, rate settlements and related filings of all pipelines held wholly or in part by the Partnership summarized above, the estimated impact of the tax-related changes to our revenue and cash flow is a reduction of approximately $30 million per year on an annualized basis beginning in 2019.

See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations-Outlook of our business" for more information.

Impairments

Bison

During the fourth quarter of 2018, two of Bison's customers elected to pay out the remainder of their future contracted obligations and terminate the associated transportation agreements. The termination of these agreements resulted in a $97 million cash payment in December 2018, which was used by the Partnership, together with other cash to repay in full the balance of our $170 million Term Loan due 2020 (2015 Term Loan Facility). The $97 million was recorded in revenue, as the contract terminations released Bison from providing any future services.

Commercial potential opportunity exists to either reverse the direction of gas flow on Bison for deliveries on to third party pipelines ultimately connecting into the Cheyenne hub or to repurpose for liquids service. However, this development, coupled with the persistence of market conditions which have inhibited system flows on the pipeline and the uncertainty regarding Bison's ability to generate positive cash flows after the expiry of its remaining customer contracts in January 2021, led us to determine the asset's current carrying value was no longer recoverable. As a result, a non-cash impairment charge of $537 million was recorded in the fourth quarter of 2018. We continue to explore alternative transportation-related options for Bison.

See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations-Critical Accounting Estimates" for more information.

Tuscarora

In the fourth quarter of 2018, Tuscarora initiated its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its maximum rates. In connection with its annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other valuation assumptions responsive to Tuscarora's environment, which included estimates related to discount rate and earnings multiples. We also considered in our overall conclusion the outcome of the January 2019 settlement-in-principle reached by Tuscarora with its customers. As a result, it was determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and the Partnership recorded a non-cash goodwill impairment charge of $59 million in the fourth quarter of 2018 and reduced our total consolidated goodwill balance from $130 million to $71 million. The goodwill balance related to Tuscarora at December 31, 2018 was $23 million (2017 – $82 million).

See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations-Critical Accounting Estimates" for more information.

Cash Distributions to Common Units and our General Partner

Our total quarterly cash distribution declared per common unit decreased from $3.94 per common unit for 2017 to $2.60 per common unit for 2018. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources" for more information.

On May 1, 2018, the board of directors of the General Partner declared the Partnership's first quarter 2018 cash distribution in the amount of $0.65 per common unit payable on May 15, 2018 to unitholders of record as of May 9, 2018. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TransCanada as a holder of 11,287,725 common units) and $1 million to the General Partner for its effective two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the first quarter 2018.

On July 26, 2018, the board of directors of the General Partner declared the Partnership's second quarter 2018 cash distribution in the amount of $0.65 per common unit payable on August 15, 2018 to unitholders of record as of August 6, 2018. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and

$7 million to another subsidiary of TransCanada as a holder of 11,287,725 common units) and $1 million to the General Partner for its effective two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the second quarter 2018.

On October 22, 2018, the board of directors of the General Partner declared the Partnership's third quarter 2018 cash distribution in the amount of $0.65 per common unit and payable on November 14, 2018 to unitholders of record as of November 2, 2018. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TransCanada as a holder of 11,287,725 common units) and $1 million to the General Partner for its effective two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the third quarter 2018.

On January 22, 2019, the board of directors of the General Partner declared the Partnership's fourth quarter 2018 cash distribution in the amount of $0.65 per common unit which was paid on February 11, 2019 to unitholders of record as of February 1, 2019. The declared distribution totaled $47 million and was paid in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TransCanada as a holder of 11,287,725 common units) and $1 million to the General Partner for its two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the fourth quarter 2018.

Incentive distributions are paid to our General Partner if quarterly cash distributions on the common units exceed levels specified in the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (as amended, the Partnership Agreement). As a result of the distribution reduction noted above, the Partnership did not pay any IDRs to our General Partner on the distributions declared from the first to the fourth quarter of 2018. 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.

Class B Distributions

On January 22, 2019, the board of directors of our General Partner declared its annual Class B distribution in the amount of $13 million which amount was paid on February 11, 2019. In 2018, the Class B distribution paid was $15 million. Please read Notes 8, 11, 14 and 15 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more detailed disclosures on the Class B units.

Other Business Developments

Portland XPress Project update – Our Portland XPress Project or "PXP" was initiated in 2017 in order to expand deliverability on the PNGTS system down to Dracut through re-contracting and construction of incremental compression within PNGTS' existing footprint in Maine. The in-service dates of the PXP project are being phased in over a three-year period which began November 1, 2018.

During the second quarter of 2018, PNGTS filed the required applications with FERC for all three phases of the project, which included an amendment to its Presidential Permit and an increase in its certificated capacity through the addition of a compressor unit at its jointly owned facility with Maritimes and Northeast Pipeline LLC to bring approximately 100,000 Dth/day of additional natural gas supply to New England. On August 28, 2018 and December 3, 2018, FERC issued positive Environmental Assessments for Phases II and III of PXP, respectively.

PNGTS expects the capital cost of PXP to be approximately $80 million. PNGTS is currently financing this project through its $125 million credit facility established in 2018 (PNGTS Revolving Credit Facility). Concurrently with PXP, TransCanada is performing upstream capacity expansions of approximately $107 million (TransCanada PXP Expenditures), the majority of which is expected to be incurred following the receipt of required regulatory approvals prior to the end of Phase II. 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 TransCanada's customers 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 that PXP does not proceed as anticipated. At December 31, 2018, the total cost incurred by these affiliates was approximately $47 million.

Westbrook XPress Project – The PXP project described above is fully subscribed, with no uncontracted firm capacity available to meet incremental market demand in this region. In response to the need for incremental supply in northern New England and Atlantic Canada, PNGTS has developed a second expansion project. PNGTS' Westbrook XPress Project (Westbrook XPress) is an estimated $100 million multi-phase expansion project that is expected to generate approximately $30 million in revenue for PNGTS on an annualized basis when fully in service. It is part of a coordinated offering to transport incremental Western Canadian Sedimentary Basin natural gas supplies to the Northeast U.S. and Atlantic Canada markets through additional compression capability at an existing PNGTS facility. Westbrook XPress is designed to be phased in over a three-year period with Phase 1 and Phase 2 estimated in-service dates of November 2019 and 2021, respectively. These two Phases will add incremental capacity of approximately 43,000 Dth/day and 63,000 Dth/day, respectively. Westbrook XPress, together with Portland XPress, will increase PNGTS' capacity by approximately 70 percent from 210,000 Dth/day to approximately 350,000 Dth/day.

Partnership structure – On December 31, 2018, the General Partner contributed its 1.0101 percent general partner interest in each of TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership (together, the "Partnership ILPs") to the Partnership (the "ILP Contribution") and received a 1 percent general partner interest in the Partnership in return for the ILP Contribution, resulting in a simplification of the General Partner's effective two percent general interest in the Partnership through its directly-held one percent and indirectly-held 1.0101 percent general partner interests in the Partnership and Partnership ILPs, respectively, prior to the contribution to a directly-held two percent general partner interest in the Partnership. The transaction is being undertaken to create a more efficient partnership structure and will have no impact on the economic interests of the general or limited partners of the Partnership. This was the first step in a series of transactions to eliminate the Partnership ILPs and more closely align the Partnership to other MLP structures existing today. The Partnership now holds 100% of the Partnership ILPs' limited partner interests and general partner interests, which general partner interests are held through a wholly-owned subsidiary of the Partnership, TC PipeLines Intermediate GP, LLC (the "ILP General Partner").

Financing

PNGTS – On April 5, 2018, PNGTS entered into a revolving credit agreement under which PNGTS has the ability to borrow up to $125 million at a variable interest rate based on LIBOR. The credit agreement matures on April 5, 2023 and requires PNGTS to maintain a leverage ratio of not greater than 5.00 to 1.00. The leverage ratio was 0.35 to 1.00 as of December 31, 2018. The facility is utilized primarily to fund the costs of the PXP expansion project and to finance PNGTS' other funding needs. As of December 31, 2018, $19 million was drawn on the PNGTS Revolving Credit Facility and the LIBOR-based interest rate was 3.60 percent.

North Baja – On December 19, 2018, North Baja entered into a variable rate $50 million three-year term loan payable at maturity (North Baja Term Loan). Under the terms of the agreement, the variable interest rate is based on LIBOR and North Baja is required to maintain a Total Debt to Total Capitalization ratio of not greater than 70 percent. As of December 31, 2018, $50 million was drawn on the North Baja Term Loan and the LIBOR-based interest rate was 3.54 percent. The proceeds drawn were utilized primarily to finance North Baja's general funding needs.

Partnership's 2015 Term Loan Facility and Senior Credit Facility – On December 31, 2018, the Partnership's 2015 Term Loan Facility was paid in full using the proceeds from Bison's contract buy-out discussed above together with the Partnership's other cash on hand. Additionally, we reduced the outstanding balance of our Senior Credit Facility by $145 million or 78 percent from $185 million at December 31, 2017 to $40 million at December 31, 2018 as part of our ongoing efforts to deleverage our balance sheet. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Result of Operations-Liquidity and Capital Resources" for more information.

Business Strategies

- Our strategy is focused on generating long-term, steady and predictable distributions to our unitholders by investing in long-life critical energy infrastructure that provides reliable delivery of energy to customers.
- Our investment approach is to develop or acquire assets that provide stable cash distributions and opportunities for new capital additions, while maintaining a low-risk profile. We are opportunistic and disciplined in our approach when identifying new investments.
- Our goal is to maximize distributable cash flows over the long term through efficient utilization of our pipeline systems and appropriate business strategies, while maintaining a commitment to safe and reliable operations.

Understanding the Natural Gas Pipeline Business

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

Regulation, rates and cost recovery

Interstate natural gas pipelines are regulated by FERC. FERC approves the construction of new pipeline facilities and regulates aspects of our business including the maximum rates that are allowed to be charged. Maximum rates are based on operating costs, which include allowances for operating and maintenance costs, income and property taxes, interest on debt, depreciation expense to recover invested capital and a return on the capital invested. During 2018, FERC issued the Revised Policy Statement and changed its long-standing policy on the treatment of income taxes for rate-making purposes for MLP-owned pipelines which has had a significant impact on MLPs in general and on their respective natural gas pipeline assets. (See also Part I within Item 1. "Business – Recent Business Developments-2017 U.S. Tax Reform, 2018 FERC Actions and its impact on our business")

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. In some cases a settlement or agreement with the pipeline's 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.

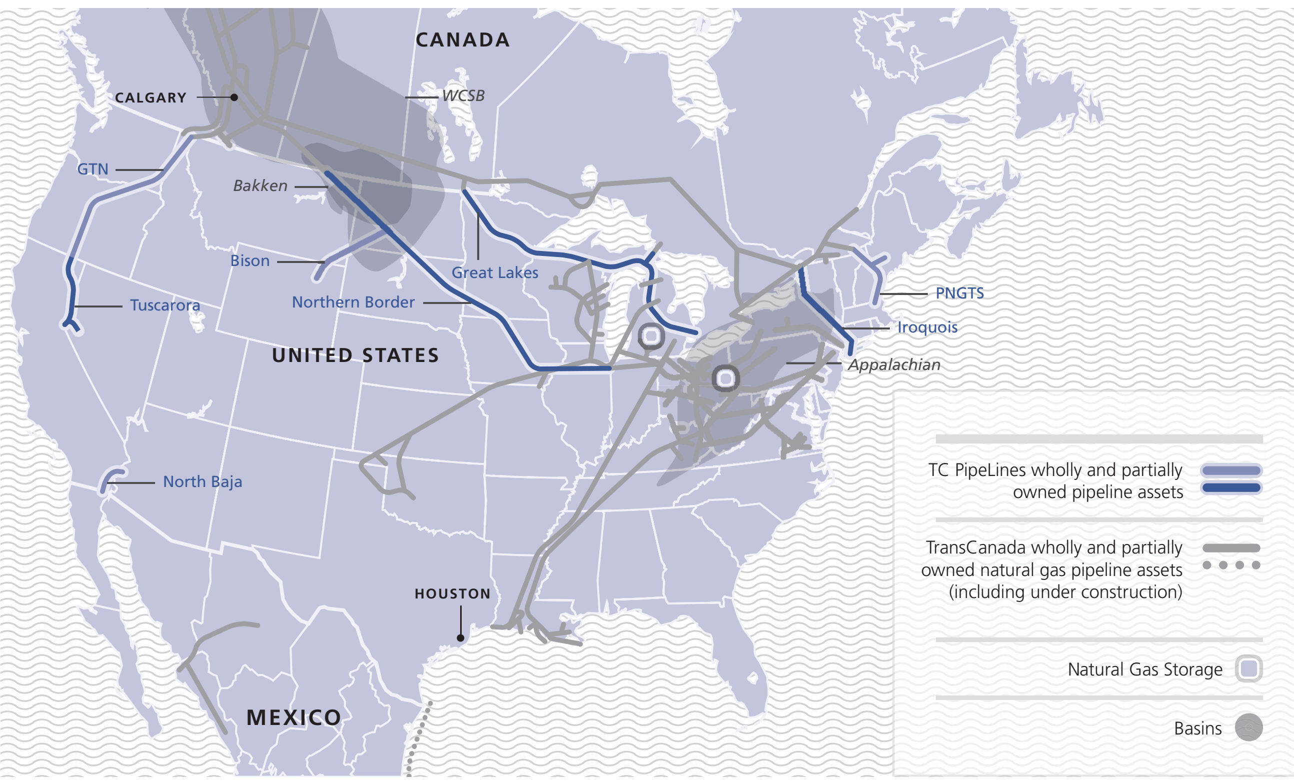
Contracting

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 and has contributed to the decline of higher-cost sources of supply (such as certain offshore gas production from Atlantic Canada) resulting in changes to historical natural gas pipeline flow patterns.

The supply of natural gas in North America is expected to continue increasing 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 natural 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 natural 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.

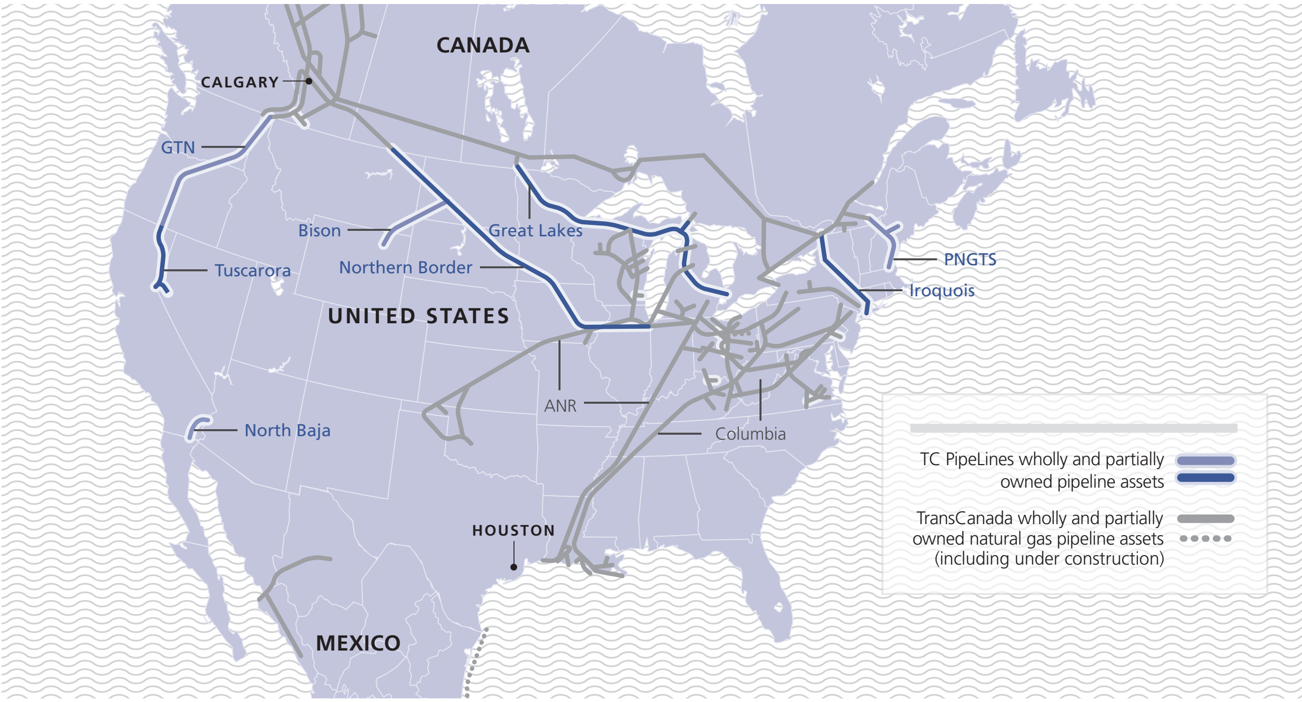
Our Pipeline Systems

We have ownership interests in eight natural gas interstate pipeline systems that are collectively designed to transport approximately 10.8 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 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 M&N Operating Company, LLC (MNOC), a subsidiary of Maritimes and Northeast Pipeline LLC (MNE). MNE is a subsidiary of Enbridge Inc.

Our pipeline systems include:

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends from 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	303 miles	Extends from a location near Gillette, Wyoming to Northern Border's pipeline system in North Dakota. Bison can, but does not currently, transport natural gas from the Powder River Basin to Midwest markets.	100 percent
North Baja	86 miles	Extends from an interconnection with the El Paso Natural Gas Company pipeline near Ehrenberg, Arizona to 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	305 miles	Extends from the terminus of 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	1,412 miles	Extends from 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 the Rocky Mountain area for deliveries to the Midwest. ONEOK Partners, L.P. owns the remaining 50 percent of Northern Border.	50 percent
PNGTS	295 miles	Connects with the TQM pipeline 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 MNE. The Joint Facilities extend from Westbrook, Maine to Dracut, Massachusetts and PNGTS owns approximately 32 percent of the Joint Facilities.	61.71 percent
Great Lakes	2,115 miles	Connects with the TransCanada Mainline at the Canadian border points 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	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

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 72 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."

Transactions with our major customers that are at least 10 percent of our consolidated revenues can be found under Note 17-Transactions with major customers within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference

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 residential and commercial LDCs and power generators that use a diversified portfolio of transportation options to serve their long-term markets and marketers under a variety of contract terms. A small portion of our contract portfolio is contracted by industrial shippers and producers. 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.

During 2018, GTN benefitted from an increase in the volumes of natural gas it transports as debottlenecking activities occurred on upstream pipeline systems which deliver natural gas to GTN. These upstream activities are continuing and as a result, we have signed over 700,000 Dth/day in long-term contracts of which 348,000 Dth/day resulted in additional volumes flowing onto GTN that began mid-2018 with the remainder expected to come on-line from 2019 to 2020. The majority of these contracts have terms of at least 15 years.

On January 29, 2019, GTN's largest customer, Pacific Gas and Electric Company (Pacific Gas), filed for Chapter 11 bankruptcy protection. Pacific Gas accounted for approximately six percent of the Partnership's consolidated revenues in 2018. As a utility company, Pacific Gas serves residential and industrial customers in the state of California and has an ongoing obligation to serve its customers, therefore we do not expect the bankruptcy of Pacific Gas to have a material impact on our future cash flows and results of operations.

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. A significant portion of Northern Border's contract portfolio is contracted by utilities, marketers and industrial load. 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.

A significant portion of Great Lakes' total contract portfolio is contracted by its affiliates including its long-term transportation agreement with TransCanada's Canadian Mainline that commenced on November 1, 2017 for a ten-year period that allows TransCanada to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from TransCanada's long-term fixed price service on its Canadian Mainline that was launched in 2017. TransCanada's long-term fixed price service provides long-term capacity to TransCanada's shippers for the transportation of WCSB natural gas to markets in Eastern Canada and the U.S.

During the second quarter of 2018, Great Lakes reached an agreement on the terms of new long-term transportation capacity contracts with its affiliate, ANR Pipeline Company. The contracts are for a term of 15 years from November 2021 to October 31, 2036 with a total contract value of approximately $1.3 billion on a 0.9 billion of cubic feet capacity. The contracts contain reduction options (i) at any time on or before April 1, 2019 for any reason and (ii) any time before April 2021, if TransCanada is not able to secure the required regulatory approval related to anticipated expansion projects.

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 entered into via a series of open seasons for long-term capacity held by PNGTS in recent years. 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.

In addition to the C2C contracts, in 2017, as a result of its PXP open season, PNGTS executed 20-year precedent agreements 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.

PXP is proceeding concurrently with upstream capacity expansions on the TQM pipeline and TransCanada's Canadian Mainline systems. The in-service dates of PXP are being phased-in over a three-year period which began 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.

PNGTS' recently-announced Westbrook XPress project is independent and designed to bring at least a further 106,000 Dth/day of capacity phased in over a three-year period with Phase 1 and Phase 2 estimated in-service dates of November 2019 and 2021, respectively. PNGTS held a successful open season for its Westbrook XPress project in December 2018, and has signed precedent agreements for Phases I and II of this project, pending receipt of various regulatory and corporate approvals.

Iroquois – Iroquois transports natural gas under long-term contracts that expire between 2019 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 2018, Iroquois earned approximately 15 percent of its revenues from discretionary services.

North Baja – The North Baja pipeline system is an 86 mile bi-directional natural gas pipeline transporting gas between Arizona, California and the Mexican border since 2002. North Baja's historical steady financial performance is due to its strong contracting levels, having a weighted average remaining firm contract length of about 8 years. North Baja currently has a design capacity of 500 mcf/d of southbound transportation and is capable of transporting 600 mcf/d in a northbound direction.

Bison – As previously disclosed, natural gas is not flowing on the Bison system in response to the recent relative cost advantage of WCSB- and Bakken -sourced gas versus Rockies production. From its in-service date in 2011 and up to the fourth quarter of 2018, Bison was fully contracted on a ship-or-pay basis. During the fourth quarter of 2018, through a Permanent Capacity Release Agreement, Tenaska Marketing Ventures ("Tenaska") assumed Anadarko Energy Services Company's ("Anadarko") ship-or-pay contract obligation on Bison, which was the largest contract on Bison and comprised approximately 60 percent of Bison's revenue. After assuming the transportation obligation, Bison accepted an offer from Tenaska to buy out this contract. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison. At the completion of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018.

These customers represent approximately 60 percent of Bison's revenue and therefore, beginning 2019 and until the remaining contracts in the system expire in January 2021, Bison will be approximately 40 percent contracted on a ship-or-pay basis and Bison's future revenue will be reduced by approximately $47 million per year in 2019 and 2020. Based on this development and other qualitative factors, the Partnership evaluated the remaining carrying value of Bison's property, plant and equipment at December 31, 2018 and concluded that the entire amount was no longer recoverable, resulting in a non-cash impairment charge during the fourth quarter of 2018. Commercial potential exists to either reverse the direction of gas flow on Bison for deliveries on to third party pipelines ultimately connecting into the Cheyenne hub or to repurpose for liquids service. See Part I within Item 1. "Business- Recent Business

Developments-Impairments and Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates" for more information.

Tuscarora – Tuscarora's 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 Bakken, 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, and gas from the Rocky Mountains that is delivered into the Midwest must compete with gas sourced from the Bakken and Western Canada.

North Baja's southbound pipeline capacity competes with deliveries of LNG received at the Costa Azul terminal in Mexico. If 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, 2018, owns, through its subsidiaries, approximately 24 percent of our common units, 100 percent of our Class B units, 100 percent of our IDRs and has a 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 liquids transmission and power generation services. TransCanada consists of investments in 57,500 miles of natural gas pipelines, 3,000 miles of wholly-owned liquids pipelines and 535 billion cubic feet of natural gas storage capacity. TransCanada also owns or has interests in over 6,600 megawatts of power generation. TransCanada operates most of our pipeline systems and, in some cases, contracts for pipeline capacity.

See also 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 rate 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.

Filings required by the Final Rule and Recent Rate Settlements

As noted under Recent Business Developments of this section, new rate settlements were entered into by GTN, Tuscarora and Iroquois to address the issues that came out of the 2018 FERC Actions. The terms of the rate settlements are outlined below:

GTN

On October 16, 2018, GTN filed an uncontested settlement with FERC to address the changes proposed by the 2018 FERC Actions on its rates via an amendment to its prior 2015 settlement (2018 GTN Settlement). Among the terms of the 2018 GTN Settlement, GTN agreed to a refund of approximately $10 million in 2018 to its firm customers reflective of reduced rates for the ten months ended October 31, 2018, as well as to reduce its existing maximum system rates by 10 percent effective January 1, 2019 through to December 31, 2019. The existing maximum rates will then decrease by an additional 6.6 percent for the period January 1, 2020 through December 31, 2021. GTN is required to have new rates in effect on January 1, 2022. These reductions will replace the 8.3% percent reduction in GTN's reservation rates in 2020 agreed upon as part of GTN's last settlement in 2015. Furthermore, GTN and its customers have agreed upon a moratorium on further rate changes until December 31, 2021. The 2018 GTN Settlement will also reflect an elimination of the tax allowance previously recovered in rates along with ADIT for rate-making purposes. The uncontested settlement, which was approved by FERC on November 30, 2018, relieved GTN of its obligation to file a Form 501-G.

Tuscarora

On December 6, 2018, Tuscarora elected to make a limited NGA Section 4 filing to reduce its maximum rates by approximately 1.7 percent and eliminate its deferred income tax balances previously used for rate setting (Option 1). On January 29, 2019, Tuscarora notified FERC that it had reached a settlement-in-principle with its customers to address the changes proposed by the 2018 FERC Actions. Moratorium provisions and other terms such as comeback provisions are still being finalized but Tuscarora agreed to continue reducing its existing maximum system rates by 1.7 percent effective February 1, 2019 as noted in its limited NGA Section 4 filing.

Iroquois

On December 6, 2018, Iroquois submitted its FERC Form No. 501-G in response to the FERC Final Rule along with an explanation as to why rate changes were not required. On January 9, 2019, Iroquois notified FERC that it had reached a settlement-in-principle with its customers to address the changes proposed by the 2018 FERC Actions. Iroquois has agreed to reduce its existing maximum system rates by the impact of the 2017 Tax Act changes as shown in Iroquois' Form 501-G filed with FERC.

Existing Settlements with subsequent limited section 4 rate reductions

Great Lakes – Great Lakes operates under a settlement approved by FERC effective January 1, 2018 (2017 Great Lakes Settlement). The 2017 Great Lakes Settlement did not contain a moratorium and eliminated its revenue sharing mechanism with customers. Great Lakes is required to file new rates effective October 1, 2022. Effective February 1, 2019, FERC approved an additional 2% rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to Great Lakes' limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and mitigated the loss of Great Lakes' tax allowance.

Northern Border – Northern Border operates under a settlement approved by FERC effective January 1, 2018 (2017 Northern Border Settlement). The 2017 Northern Border Settlement provided for tiered rate reductions from January 1, 2018 to December 31, 2019 that equates to an overall rate reduction of 12.5% by January 1, 2020 (10.5% by December 31, 2019 and additional 2% by January 1, 2020). The 2017 Northern Border Settlement did not contain a moratorium and Northern Border is required to file new rates effective July 1, 2024. Effective February 1, 2019, FERC approved an additional 2% rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to Northern Border's limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and mitigated the loss of Northern Border's tax allowance. Northern Border is in discussion with customers to extend the additional 2% rate reduction beyond 2019.

Bison – Bison operates 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 operates under the rates approved by FERC in its original certificate proceeding in 2001 and has no requirement to file a new rate proceeding. Effective December 1, 2019, FERC approved a 10.8% rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to North Baja's limited NGA Section 4 filing. The removal of ADIT increased net recoverable rate base and partially mitigated the loss of North Baja's tax allowance.

PNGTS – PNGTS operates 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.

NOI on Certificate Policy Statement

FERC issued a Notice of Inquiry on April 19, 2018 ("Certificate Policy Statement NOI"), thereby initiating a review of 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 as a result of the

Certificate Policy Statement NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. Any proposed changes to the current policy will be prospective only and it is expected that FERC will take many months to determine whether there will be any changes to proposed natural gas pipeline projects. We do not expect changes in this policy to affect us in a materially different manner than other similarly sized natural gas pipeline companies operating in the United States.

Environmental Matters
Our pipelines are subject to stringent and complex U.S. 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, restrictions, or cancellations in the permitting or performance of projects and/or the issuance of orders limiting or prohibiting operations in affected areas.

The more significant of these existing environmental laws and regulations include the following U.S. legal standards, as amended from time to time:

- the Clean Air Act (CAA), which regulates air pollution on a national level by restricting the emission of air pollutants from many sources and imposes various pre-construction, operational, monitoring, and reporting requirements, and provides EPA statutory authority for adopting climate change regulatory initiatives relating to greenhouse gas (GHG) emissions;
- the Federal Water Pollution Control Act, also known as the Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the Oil Pollution Act of 1990, which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States;
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- the Resource Conservation and Recovery Act (RCRA), which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- the Toxic Substances Control Act (TSCA), which governs 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, including polychlorinated biphenyls (PCBs), asbestos, radon, and lead-based paint;
- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories;
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats by the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- the National Environmental Policy Act, which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment; and

- the Department of Transportation regulations, which relate to advancing the safe transportation of energy and hazardous materials and emergency response preparedness.

Additionally, there exist regional, state and local jurisdictions in the United States where we operate that also have, or are developing or considering developing, similar environmental laws and regulations governing many of these same types of activities. While the legal requirements imposed in state and local jurisdictions may be similar in form to federal laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent conditions or controls that can significantly restrict, delay or cancel the permitting, development, or expansion of a project or substantially increase the cost of doing business. Additionally, our operations may require state-law based permits in addition to federal permits, requiring state agencies to consider a range of issues, many the same as federal agencies. Additionally, multiple environmental laws provide for citizen suits, which allow private parties, including environmental organizations, to act in place of the government and sue operators for alleged violations of environmental law. See Risk Factors under Part I, Item 1A of this Form 10 K for further discussion on environmental laws and regulations, including with respect to climate change, including methane and other GHG emissions, ozone standards, site remediation; and other regulations relating to environmental protection. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards or more stringent enforcement programs continue to evolve.

We have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental laws and regulations. The trend in environmental regulation is to place more restrictions on activities that may affect the environment and, thus, any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly pollution control equipment, the occurrence of restrictions, delays or cancellations in the permitting or performance of projects, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results.

Pipeline Safety Matters

Our gas 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 U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities 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 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. 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 2016 Pipeline Safety Act extended PHMSA's statutory mandate through 2019 and, among other things, required PHMSA to complete certain outstanding mandates under the 2011 Act.

During 2016 PHMSA also proposed new rules and issued a Notice of Public Rule Making for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting, and integrity management requirements on operators. In 2018, PHMSA announced that it would divide the proposed new rule into three separate rulemakings, focusing on (1) maximum allowable operating pressure, integrity assessments and moderate consequence areas; (2) repair criteria, safety features for pigging, inspections and corrosion control; and (3) gathering lines. PHMSA is expected to publish the three separate rulemakings in 2019. PHMSA continues to engage industry and other stakeholders in development of these rules as well as other provisions. Any implementation of rules or reinterpretation of guidance by PHMSA, or any other state agencies, 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 these actions could result in a significant increase in operating costs and have a material adverse effect on our results of operations or financial condition.

On July 31, 2018, PHMSA published an advance notice of proposed rulemaking (ANPRM) requesting public comment on the additional safety measures pipelines facilities are required to take in response to class location changes due to population growth. The class location concept predates the extension of Integrity Management (IM) principles and it has been argued that public safety can be improved if IM measures are implemented as an alternative to pressure reductions, pipe replacements, or hydrostatic pressure testing. While this rulemaking process is expected to be lengthy, efforts to modernize the existing PHMSA regulations may have a material effect on costs.

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 and, despite compliance with applicable rules and regulations, our pipelines may experience leaks and ruptures that could impact the surrounding population and environment. This may result in civil and/or criminal fines and penalties or third-party property damage claims, and could require additional testing or upgrades on the pipeline system unrelated to the incident. It is possible that these costs may not be covered by insurance or recoverable through rate increases. 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.

Occupational Safety and Health Administration (OSHA)

Our pipelines are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act and comparable state statutes, whose purpose is to protect the health and safety of workers. The OSHA and analogous state agencies oversee the implementation of these laws and regulations. Additionally, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Historically, worker safety and health compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results. While pipeline operators may increase expenditures in the future to comply with higher industry and regulatory safety standards, 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 and 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 may cover losses from physical damage to our facilities as a result of a cyber security event, but insurance does not cover all events in all circumstances. 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 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.

Failure to complete organic growth projects or acquire additional assets may inhibit our strategy of providing long-term steady and predictable cash distributions.

TransCanada has historically sold certain of its FERC-regulated assets to the Partnership via dropdown transactions, subject to TransCanada's funding needs and market conditions. In the absence of dropdowns from TransCanada our opportunities will come from organic growth projects on our existing pipeline systems along with potential third-party acquisitions. It is uncertain as to whether or when we could be restored as a viable funding vehicle for TransCanada.

If we cannot successfully finance and complete expansion projects or make and integrate acquisitions that are accretive or our assumptions about the impact of the tax-related change to our revenue and cashflows are incorrect, we may not be able to maintain historical levels of cash flow and distributions. For example, if we are unable to replace cash flow that may be reduced through future rate proceedings or contract expirations on our pipeline systems, we could be required to take additional proactive measures, including further reductions in distributions, to facilitate repayments of debt as may be needed to maintain compliance with financial covenants, in addition to taking other significant strategic actions.

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, 2018, $168 million of our total $2,118 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, 2018, the $500 million 2013 Term Loan Facility was hedged by 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 some expansion capital expenditures, we may 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 may be less favorable to us and 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.

Any impairment of our goodwill, long-lived assets or equity investments will reduce our earnings and could negatively impact the value of our common units

In the fourth quarter of 2018, we recognized impairment charges on Tuscarora's goodwill balance amounting to $59 million and Bison's long-lived assets totaling $537 million. Consistent with U.S. Generally Accepted Accounting Principles (GAAP), we evaluate our goodwill for impairment at least annually. On our long-lived assets and equity investments, 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, not just that of 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 non-cash charge to earnings with a corresponding 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.

The risk of future impairments related to our goodwill, long-lived assets or equity investments, will continue to exist. If underlying business assumptions change, there can be no assurance that a future impairment charge will not be made with respect to our remaining balances of our goodwill, equity investments 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 Goodwill, Long-Lived Assets and 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 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.

Rates and other terms of service for our pipeline systems are subject to approval and potential adjustment by FERC, which could limit the 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 Natural Gas Act, their rates must be just, reasonable and not unduly discriminatory. Actions by FERC, such as refusing to honor existing moratoria on rate changes, could adversely affect our pipeline systems' ability to recover all current or future costs and could negatively impact their rate of return, results of operations and cash available for distribution which could result into a lower overall Partnership distributable cashflow than anticipated, which could necessitate a further distribution reduction. See also in Part I, Item 1 "Business – Government Regulation" for further information on impacts related to actions by FERC.

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, 2018, the total incurred was approximately $47 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 $1.27 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, we are subject to pipeline safety requirements that may impose more stringent safety obligations, require installation of new or modified safety controls, or perform capital or operating projects on an accelerated basis. 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 in recent years 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 operating and capital costs and result in operational delays.

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. See "Government Regulation" – "Pipeline Safety Matters" under Part I, Item 1 of this Form 10 K for further discussion on pipeline safety matters.

Our pipeline systems are regulated by federal, state and local environmental laws and regulations that could impose significant costs and liabilities 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, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either "attainment/unclassifiable", "unclassifiable" or "non-attainment." Additionally, in November 2018, the EPA issued final requirements that apply to state, local, and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs. Also, in 2015, the EPA and U.S. Army Corps of Engineers ("Corps") released a final rule outlining federal jurisdictional reach under the Clean Water Act over waters of the United States, including wetlands. Beginning in the first quarter of 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, the agencies have (i) published a proposed rule in July 2017 to rescind the 2015 rule and recodify the regulatory text that governed waters of the United States prior to promulgation of the 2015 rule, (ii) published a final rule in February 2018 adding a February 6, 2020 applicable date to the 2015 rule, and (iii) published a proposed rule in December 2018 re-defining the Clean Water Act's jurisdiction over waters of the United States for which the agencies will seek public comment. The 2015 and February 2018 final rules are being challenged by various factions in federal district court and implementation of the 2015 rule has been enjoined in twenty-eight states pending resolution of the various federal district court challenges. As a result of these legal developments, future implementation of the 2015 rule or a revised rule is uncertain at this time. Compliance with these regulations or other laws, regulations and regulatory initiatives, or any other new environmental legal requirements could, among other things, require us to install new or modified emission controls on equipment or processes, incur longer permitting timelines, and incur significantly increased capital or operating expenditures.

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. Moreover, an accidental release of materials into the environment during the course of our operations may cause us to incur significant costs and liabilities. Remedial costs and other damages arising as a result of environmental laws and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on our liquidity, results of operations and financial condition. See "Government Regulation" – "Environmental Matters" under Part I, Item 1 of this Form 10 K for further discussion on environmental matters.

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.

Climate change legislation and regulations restricting or regulating emissions of GHGs could result in increased operating and capital costs for our customers and reduced demand for our systems and services.

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, regional and state levels of government to monitor and limit emissions of GHGs. While no comprehensive climate change legislation has been implemented at the federal level, the EPA and states or groupings of states have pursued legal initiatives in recent years that seek to reduce GHG emissions through efforts that include consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In particular, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted rules under authority of the CAA that, among other things, establish certain Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already potential sources of certain pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. The EPA has also promulgated regulations requiring annual monitoring and reporting of GHG emissions in the U.S. from, among other sources, certain onshore natural gas transmission and storage facilities and blowdowns of natural gas transmission pipelines between compressor stations.

Federal agencies also have begun directly regulating emissions of methane, a GHG from oil and natural gas operations. In 2016, the EPA published a final rule establishing federal New Source Performance Standards (NSPS) Subpart OOOOa, that requires certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and specific volatile organic compound emissions. These Subpart OOOOa standards expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices. In 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years, but the EPA has not yet published a final rule. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule and, in September 2018, the agency proposed additional amendments that included rescission or revision of certain requirements such as fugitive emission monitoring frequency. This rule, should it remain in effect, and any other new methane emission standards imposed on the oil and natural gas sector could result in increased costs to our or our customers' operations as well as result in restrictions, delays or cancellations in such operations, which developments could adversely affect our business. Additionally, in April 2016, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement negotiated in Paris, France for nations to limit their GHG emissions through individually-determined emission reduction goals every five years beginning in 2020. However, in August 2017, the U.S. State Department informed the United Nations of the United States' intention to withdraw from this Paris agreement, which provides for a four-year exit process beginning when it took effect in November 2016. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

At the state level, there have been a number of legislative initiatives to regulate GHG emissions, recently including proposed "cap and invest" and "cap and trade" legislation in Oregon and Washington, respectively. The proposals could have resulted in taxes or fees assessed against energy companies for the carbon content of fossil fuels and electricity used or sold. The proposals were unsuccessful during the last legislative session but are expected to be reintroduced this year.

The adoption and implementation of any international, federal, regional or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our systems and services, results of operations, and cash flows. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and natural gas will continue to represent a major share of global energy use through 2040, and other studies by the private sector project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such climate changes were to occur, they could have an adverse effect on our financial condition and results of operations and the financial condition and operations of our customers.

Chemical substances in the natural gas our pipeline systems transport could cause damage or affect the ability of our pipeline systems' or third-party equipment to function properly, which may result in increased preventative and corrective action costs.

GTN recently identified the presence of a chemical substance, dithiazine, at several facilities on the GTN system and those of some upstream and downstream connecting pipeline facilities. Dithiazine is a byproduct of triazine which is liquid chemical scavenger known to be used in natural gas processing to remove hydrogen sulfide from natural gas. It has been determined that dithiazine may drop out of gas streams, under certain conditions, in a powdery form at some points of pressure reduction (for example, at a regulator). In incidents where a sufficient quantity of the material accumulates in certain appurtenances, improper functioning of equipment can occur resulting in increased preventative and corrective action costs.

While we believe that the intermittent presence of dithiazine on our pipeline systems is from upstream sourced gas, we have advised stakeholders of potential risks, mitigation efforts and safety measures. With appropriate inspection and maintenance protocols, we do not believe there are any imminent material safety issues to people, equipment or the environment on our pipeline system. We cannot speculate on the impact to customers, some of which may not have adequate overpressure protection. Notwithstanding, due to the potential for dithiazine to interfere with equipment functionality, the Partnership is considering disallowing the receipt of gas that has interacted with triazine into the GTN system if the presence of dithiazine does not change. Our pipeline systems, and other stakeholders, are actively gathering information on the substance, seeking potential options to address the issue, and have informed federal and state regulators, trade associations, and other stakeholders of this information.

We are currently evaluating interim and long-term solutions to address the presence of dithiazine and, at this time, GTN continues to make capital expenditures to address the matter. During 2018, we incurred capital expenditures of approximately $5 million and, unless this is resolved, we expect to spend approximately $5 million per year in the next two years to further mitigate the matter. There can be no assurance that significant costs will not be incurred in the future or that dithiazine or other substances will not be identified on our other pipeline systems.

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 result 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 are generally 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 from our pipeline systems.

Our Great Lakes pipeline system has rights-of-ways that expired 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 and 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 agreements 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 66⅔ 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 approximately 24 percent of our outstanding common units at December 31, 2018, 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, 2018, the General Partner and its affiliates own approximately 24 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, 2018, we paid fees and reimbursements to our General Partner in the amount of $4 million (2017 – $ 4 million and 2016 – $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 and exemption from entity level taxes for U.S. federal, state and local income tax purposes. If we were to be treated as a corporation or otherwise become subject to a material amount of entity level taxation for U.S. federal, state and local tax purposes, our cash available for distribution to unitholders and the value of our common units could be substantially reduced.

The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for U.S. 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 if the IRS were to determine that we fail to 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 any legislative, administrative or judicial 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 at the entity level.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. 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. In the event of a tax imposed upon us as a corporation, the cash available for distribution to our unitholders could be substantially reduced and result in a material reduction in the anticipated cash flow and after-tax return to unitholders, which in turn would likely have a negative impact on the value of our 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 U.S. 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 cash distributions to unitholders.

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 Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships including a prior legislative proposal that would have eliminated the qualifying income exception we rely upon; thus, treating all publicly traded partnerships as corporations for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a publicly traded partnership in the future.

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 changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your 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 our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

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 our common units 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.

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. The Partnership has taken certain positions regarding our unitholders' ability to deduct our interest expense. If the IRS contests these positions or if further guidance is issued contrary to the positions taken, the unitholder's ability to deduct this interest expense could 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. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) 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 common 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 common units will generally be considered "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 common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common 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 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 common units each month based upon the ownership of our common 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 common units each month based upon the ownership of our common 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 common 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 common 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 common 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 common 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 common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common 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 and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

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 70 miles of our Great Lakes pipeline system are 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 expired in the second quarter of 2018. Great Lakes is in discussions with tribal authorities for the renewal of approximately 7.6 miles of pipeline rights-of-way. 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. These permanent easements were acquired prior to the tribe's acquisition of the land and will not become subject to renewal. See Part I, Item 1A "Risk Factors – Risks Related To Our Pipeline Systems" for further information.

Item 3. Legal Proceedings

We are involved in various legal proceedings from time to time that arise in the ordinary course of business. Information regarding our pipeline systems' rate proceedings is described in Item 1. "Business – Government Regulation – Regulatory and Rate Proceedings" is incorporated herein by reference. Information on our legal proceedings can be found under Note 22-Contingencies within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

None.

PART II

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

As of February 20, 2019, 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 20, 2019, 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 a 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.

Further details regarding our distributions can be found under Note 15-Cash Distributions within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference

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)	**2018**	2017	2016[(a)]	2015[(a)]	2014[(a)]
Income Data (for the year ended December 31)					
Transmission revenues	**549[(e)]**	422	426	417	410
Equity earnings[(b)]	**173**	124	97	97	88
Impairment of equity-method investment[(c)]	**–**	–	–	(199)	–
Impairment of goodwill[(d)]	**59**	–	–	–	–
Impairment of long-lived assets[(e)]	**537**	–	–	–	–
Net income (loss)	**(165)**	263	263	58	241
Net income (loss) attributable to controlling interests	**(182)**	252	248	37	195
Basic and diluted net (loss) income per common unit	**$(2.68)**	$3.16	$3.21[(f)]	$(0.03)[(f)]	$2.67[(f)]
Cash Flow Data (for the year ended December 31)					
Cash distribution declared per common unit	**$2.60**	$3.94	$3.71	$3.51	$3.33
Balance Sheet Data (at December 31)					
Total assets	**2,899**	3,559	3,354	3,459[(g)]	3,802[(g)]
Long-term debt (including current maturities)	**2,108**	2,403	1,911	1,971[(g)]	1,778[(g)]
Partners' equity	**699**	1,068	1,272	1,391	1,818

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

(c) Represents the impairment charge on our investment in Great Lakes. The equity earnings as presented in 2015 did not include this impairment charge.

(d) Please read Note 4-Goodwill and Regulatory, Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules" for more information

(e) Please read Note 7- Property, plant and Equipment, Notes to the Consolidated Financial Statements included in Part IV Item 15. "Exhibits and Financial Statement Schedules" for more information

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

(g) 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, 2018 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 2016 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 8 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 loss attributable to controlling interests was $182 million or a loss of $2.68 per common unit in 2018 compared to income of $252 million or $3.16 per common unit in 2017. Adjusted earnings, which excludes the impact of the $596 million non-cash impairment charges on Bison and Tuscarora and the $97 million revenue recognized as a result of the contract buy-out at Bison were $317 million or $4.18 per common unit in 2018, an increase of $65 million or $1.02 per common unit over 2017 earnings. As a result of the expected impact of the 2018 FERC Actions starting in

2019, our cash distributions declared per common unit decreased from $3.94 per common unit in 2017 to $2.60 per common unit in 2018.

Our 2018 EBITDA decreased by $418 million to $27 million compared to $445 million in 2017 primarily due to the recognition of $596 million of non-cash impairment charges on Bison and Tuscarora partially offset by the $97 million revenue received from Bison's contract buy-out. Our Adjusted EBITDA, which excludes the impact of these one-time items, increased by 18 percent to $526 million and Distributable cash flow increased by 26 percent to $391 million. Please see "Non-GAAP Financial Measures: Adjusted earnings and Adjusted earnings per common unit" for more information.

Please see "Item 1. Business- Recent Business Developments" for more information on the 2018 FERC Actions and its impact on our business, Tuscarora's goodwill impairment and Bison's impairment and contract buy-out.

Outlook of Our Business

With the 2018 FERC Actions and the uncertainty surrounding the magnitude of their impact substantially behind us, we believe our pipeline systems, which are largely backed by long-term ship-or-pay contracts, will deliver consistent financial performance going forward and support our current quarterly distribution level of $0.65 per common unit for the foreseeable future.

As the Partnership does not anticipate further dropdown transactions from TransCanada under current market conditions, we will focus on taking advantage of North America's abundant natural gas supply and our assets' connectivity to premium markets to compete for organic growth within our existing footprint, such as PNGTS' Westbrook XPress project. Our largest assets, GTN, Northern Border and Great Lakes, benefited from positive market conditions in 2018. We are actively seeking opportunities to further optimize their capacity through potential expansion projects or commercial, regulatory and operational changes in response to positive supply fundamentals. Our Iroquois and Tuscarora pipelines are expected to continue to deliver steady results.

We continue to evaluate redeployment alternatives for our Bison pipeline following expiration of its remaining long-term contracts in January 2021, including the potential to repurpose it for liquids service or reversing the pipeline to transport growing associated natural gas supplies from the Bakken or low-cost supplies from the Western Canada Sedimentary Basin (WCSB). The safe and reliable operation of our pipeline assets remains our top priority as we prudently fund ongoing capital expenditures, repay debt and manage our financial metrics.

Please see "Item 1. Business- Recent Business Developments" for more information on the 2018 FERC Actions.

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 each enhance the understanding of our operating performance. We use the following non-GAAP measures:

EBITDA

We use EBITDA as an approximate measure of our 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

The evaluation of our financial performance and position from the perspective of earnings and EBITDA is inclusive of the following items which are one-time or non-cash in nature:

- Bison's contract buy-out proceeds amounting to $97 million recognized as revenue;
- the $537 million impairment charge related to Bison's remaining balance of property, plant and equipment; and
- the $59 million impairment charge related to Tuscarora's goodwill.

However, we do not believe this is reflective of our underlying operations during the periods presented. Therefore, we have presented Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit as non-GAAP measures that exclude the impacts of the $596 million non-cash impairment charges and the one-time $97 million revenue item relating to Bison's contract buy-out.

Distributable Cash Flows

Total distributable cash flow and distributable cash flow provide measures of distributable cash generated during the current earnings period. Our distributable cash flow includes Adjusted EBITDA and therefore excludes the $596 million non-cash impairment charges and the one-time $97 million revenue item from receipt of proceeds relating to Bison's contract buy-out.

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

RESULTS OF OPERATIONS

The ownership interests 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, 2018 Compared with the Year Ended December 31, 2017

(unaudited) *(millions of dollars, except per common unit amounts)*	**2018**	2017	$ Change(b)	% Change(b)
Transmission revenues	**549**	422	127	30
Equity earnings	**173**	124	49	40
Impairment of long lived assets	**(537)**	–	(537)	(100)
Impairment of goodwill	**(59)**	–	(59)	(100)
Operating, maintenance and administrative	**(101)**	(103)	2	2
Depreciation	**(97)**	(97)	–	–
Financial charges and other	**(92)**	(82)	(10)	(12)
Net income (loss) before taxes	**(164)**	264	(428)	*
Income taxes	**(1)**	(1)	–	–
Net income (loss)	**(165)**	263	(428)	*
Net income attributable to non-controlling interests	**17**	11	6	55
Net income (loss) attributable to controlling interests	**(182)**	252	(434)	*
Adjusted earnings(a)	**317**	252	65	26
Net income (loss) per common unit	**(2.68)**	3.16	5.84	*
Adjusted earnings per common unit(a)	**4.18**	3.16	1.02	32

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

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

* Change is greater than 100 percent.

During 2018, the Partnership generated a net loss attributable to controlling interests of $182 million compared to net income of $252 million in 2017, resulting in a net loss per common unit during the year of $2.68 after allocations to the General Partner and to the Class B units. The resulting loss was primarily due to the recognition of non-cash impairments relating to Bison's property, plant and equipment and Tuscarora's goodwill partially offset by the $97 million revenue proceeds from Bison's contract buy-out. (See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates – Impairment of Goodwill, Long-Lived Assets and Equity Investments" section for more details)

Adjusted earnings increased by $65 million, an increase of $1.02 per common unit. This increase was primarily due to the net effect of:

Transmission revenues – Excluding the $97 million revenue proceeds from Bison's contract buy-out, our 2018 annual revenues were higher than those in 2017 by $30 million due to the following:

- Higher net revenue from GTN primarily due to incremental long-term services sold by GTN associated with increased available upstream capacity following debottlenecking activities on TransCanada's pipelines partially offset by lower revenues from its short-term discretionary services compared to the same period in 2017. The increase was further offset by the $10 million provision for revenue sharing payment made by GTN as part of the 2018 GTN Settlement whereby GTN agreed to refund $10 million to its maximum rate customers from January 1 to October 31, 2018;

- Higher revenue from PNGTS primarily due to incremental contracting from PNGTS' C2C contracts and the PXP Phase 1 contracts combined with an increase in discretionary services due to inclement weather in the northeast during the first quarter of 2018, partially offset by certain expiring winter contracts; and
- Increase in short-term firm transportation services sold by North Baja.

Equity earnings – The $49 million increase in 2018 compared to 2017 was primarily due to the inclusion of equity earnings from Iroquois for the full twelve months of 2018 compared to only seven months in 2017 (our 49.34 percent ownership was effective June 1, 2017), as well as the increase in Iroquois' short-term discretionary services sold during the 2018 period as a result of the colder winter weather in the Northeast. Additionally, equity earnings from Great Lakes increased as a result of higher short-term incremental sales during the year and the elimination of Great Lakes' revenue sharing mechanism that began in 2018 as part of 2017 Great Lakes Settlement.

Financial charges and other – The $10 million increase was mainly attributable to additional borrowings to finance the 2017 Acquisition combined with an increase in interest charges on our variable rate debt.

Net income attributable to non-controlling interests – The Partnership had a net increase amounting to $6 million primarily due to the increase in revenue earned by PNGTS.

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[c]	% 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 (loss) per common unit	**3.16**	3.21[b]	(0.05)	(2)

[a] Financial information was recast to consolidate PNGTS. 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 results were comparable to those in 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.

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	**2018**	2017	2016
Net income attributable to controlling interests	**(182)**	252	248
Add: Impairment of goodwill	**59**	–	–
Add: Impairment of long lived assets	**537**	–	–
Less: Revenue proceeds from Bison's contract buy-out	**(97)**	–	–
Adjusted earnings	**317**	252	248

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

Year ended December 31	**2018**	2017	2016
Net income (loss) per common unit-basic and diluted[(b)]	**(2.68)**	3.16	3.21[(a)]
Add: per unit impact of impairment of goodwill[(c)]	**0.81**	–	–
Add: per unit impact of impairment of long lived assets[(d)]	**7.38**	–	–
Less: per unit impact of revenue proceeds from Bison's contract buy-out[(e)]	**(1.33)**	–	–
Adjusted earnings per common unit	**4.18**	3.16	3.21

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

(b) See also Note 14 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 $59 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

(d) Computed by dividing the $537 million impairment charge, after deduction of amounts attributable to the General Partner with respect to its two percent interest, by the weighted average number of common units outstanding during the period.

(e) Computed by dividing the $97 million revenue, after deduction of amounts attributable to the General Partner with respect to its 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 Senior Credit Facility. The Partnership funds 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.

As a result of the 2018 FERC Actions initially proposed in March 2018, the Partnership reduced its 2018 quarterly distribution to $0.65 per common unit, a 35 percent reduction from the fourth quarter 2017 distribution of $1.00 per common unit. Cash retained by the Partnership is being used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage our financial metrics.

At December 31, 2018, our cash and cash equivalents were unchanged from our position at December 31, 2017 but our leverage was significantly lower. In 2018, we reduced the outstanding balance of our Senior Credit Facility by 78 percent, from $185 million at December 31, 2017 to $40 million at December 31, 2018, and repaid the Partnership's 2015 Term Loan Facility using the proceeds from Bison's contract buy-out together with other cash such that the Partnership's overall consolidated total debt was reduced by 12 percent, from $2,403 million in December 31, 2017 to $2,108 million at December 31, 2018. We believe our cash position, remaining borrowing capacity on our Senior Credit Facility (see table below), and our operating cash flows are adequate to fund our short-term liquidity requirements, including the revised distributions to our unitholders, ongoing capital expenditures and required debt repayments.

The following table sets forth the available borrowing capacity under the Partnership's Senior Credit Facility:

(millions of dollars) *December 31*	**2018**	2017	2016
Total capacity under the Senior Credit Facility	**500**	500	500
Less: Outstanding borrowings under the Senior Credit Facility	**40**	185	160
Available capacity under the Senior Credit Facility	**460**	315	340

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)*	**2018**	2017	2016[(a)]
Net cash provided by (used in):			
Operating activities	**540**	376	417
Investing activities	**(35)**	(761)	(230)
Financing activities	**(505)**	354	(178)
Net increase in cash and cash equivalents	**–**	(31)	9
Cash and cash equivalents at beginning of the period	**33**	64	55
Cash and cash equivalents at end of the period	**33**	33	64

(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, 2018 compared to Same Period in 2017

Operating Cash Flows

Net cash provided by operating activities increased by $164 million in the twelve months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of:

- higher cash flow from operations at Bison due to the $97 million cash proceeds received from the contract buy-out agreement reached with two of its customers as described in the "Results of Operations" and Critical Accounting Estimates – Impairment of Goodwill, Long-Lived Assets and Equity Investments sections;
- addition of distributions from Iroquois for the twelve months in 2018 as compared to the period from June 1, 2017 to the end of December in 2017;
- higher distributions received from Great Lakes primarily due to an increase in its revenue as a result of its higher short-term incremental sales during the year and the elimination of Great Lakes' revenue sharing mechanism that began in 2018 as part of Great Lakes rate settlement in 2017;
- higher cash flow from operations at PNGTS and North Baja primarily resulting from an increase in their revenues; PNGTS' revenue was higher due to its incremental contracting partially offset by certain expiring winter contracts while North Baja's revenue was higher due to an increase in its short-term firm transportation services; and
- higher interest paid attributable to additional borrowings to finance the 2017 Acquisition.

Investing Cash Flows

Net cash used in investing activities decreased by $726 million in the twelve months ended December 31, 2018 compared to the same period in 2017 due to the net effect of:

- $646 million total cash payments to TransCanada during 2017 for the 2017 Acquisition;
- $83 million equity contribution to Northern Border in 2017 representing our 50 percent share of a requested capital contribution to reduce the outstanding balance of Northern Border's revolving credit facility;
- $10 million unrestricted cash distribution received from Iroquois during 2018, which was $5 million higher than the amount received in 2017;
- $11 million increase in capital expenditures in 2018 related to ongoing maintenance projects; the increase in 2018 reflected timing of payments as the scope of the maintenance work was relatively comparable in 2018 and 2017; and
- $3 million increase in customer advances for construction related to an interconnect project on GTN.

Financing Cash Flows
During the twelve months ended December 31, 2018, we realized a net cash out-flow in our financing activities compared to a net inflow in 2017 primarily due to $297 million in net debt repayments in 2018 compared to $492 million in net debt issuance in 2017. In 2018, we repaid the entire balance of our $170 million 2015 Term Loan while in 2017, we issued $500 million 3.90% Senior Notes on May 25, 2017 to partially finance the 2017 Acquisition.

In addition to these activities, the change in our financing activities year-over-year was impacted by the net effect of the following:

- $66 million decrease in distributions paid on our common units and to our General Partner in respect of its two percent general partner interest and IDRs as a result of the 35 percent reduction in distributions declared from the fourth quarter 2017 distribution of $1.00 per common unit to $0.65 per common unit that began in the first quarter of 2018;
- $7 million decrease in distributions paid to Class B units in 2018 as compared to 2017 due to the Class B Reduction;
- $136 million decrease in our At-the-market (ATM) equity issuances in 2018 as compared to 2017; and
- $9 million increase in distributions paid to non-controlling interests due to higher revenues at PNGTS compared to 2017.

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 2017 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 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.

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)*	**2018**	2017	2016[a]
Maintenance	**60**	63	31
Growth	**7**	3	5
Total[b]	**67**	66	36

[a] Financial information was recast in 2016 to reflect our 61.71 percent share of PNGTS' capital spending for all periods presented. 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, 2018 Compared with the Year Ended December 31, 2017
Maintenance capital spending decreased by $3 million in 2018 compared to 2017 mainly due to decreases in pipeline integrity and communication projects on GTN during 2017 in addition to a decrease in expenditures for remediation and automation projects on Northern Border in 2018 compared to 2017, partially offset by an increase in integrity and reliability projects on GTN.

Capital expenditures on growth projects increased by $4 million between 2017 and 2018 due to the PXP expansion project on PNGTS and an interconnect project on Northern Border.

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.

Cash Flow Outlook

Operating Cash Flow Outlook
During the first quarter of 2019, the Partnership received or expects to receive the following distributions from our equity investments:

Northern Border declared its December 2018 distribution of $18 million on January 7, 2019, of which the Partnership received its 50 percent share or $9 million on January 31, 2019.

Northern Border declared its January 2019 distribution of $20 million on February 14, 2019, of which the Partnership will receive its 50 percent share or $10 million on February 28, 2019.

Great Lakes declared its fourth quarter 2018 distribution of $36 million on January 15, 2019, of which the Partnership received its 46.45 percent share or $17 million on February 1, 2019.

Iroquois declared its fourth quarter 2018 distribution of $28 million on January 22, 2019, of which the Partnership received its 49.34 percent share or $14 million on February 1, 2019.

Investing Cash Flow Outlook
The Partnership expects to make a $10 million contribution in 2019 to fund debt repayments of Great Lakes which is consistent with prior years.

In 2019, our pipeline systems expect to invest approximately $140 million in maintenance of existing facilities and approximately $19 million in growth projects, of which the Partnership's share would be $97 million and $11 million, respectively. Our consolidated entities have commitments of $6 million as of December 31, 2018 in connection with various maintenance and general plant projects.

Financing Cash Flow Outlook
On January 22, 2019, the board of directors of our General Partner declared the Partnership's fourth quarter 2018 cash distribution in the amount of $0.65 per common unit which was paid on February 11, 2019 to unitholders of record as of February 1, 2019. The total amount of cash distribution paid to common unitholders and General Partner was $47 million.

On January 22, 2019, the board of directors of our General Partner declared distributions to Class B unitholders in the amount of $13 million which was paid on February 11, 2019. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2018 less the threshold level of $20 million and the Class B Reduction. For 2019, the threshold level is the same and we anticipate such threshold will be exceeded in the third quarter of 2019.

Please read Notes 8, 11, 14 and 15, 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 being financed through the new $125 million credit facility at PNGTS.

As of February 21, 2019, the available borrowing capacity on our Senior Credit Facility was $475 million as a result of the $15 million payment made on February 1, 2019.

Non-GAAP Financial Measures: EBITDA, Adjusted EBITDA, Distributable Cash Flow, Adjusted Earnings and Adjusted Earnings per Common Unit

EBITDA is an approximate measure of our operating profitability 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 for the year ended December 31, 2018 excludes the impact of the following:

- Bison's contract buy-out proceeds amounting to $97 million recognized as revenue during the fourth quarter of 2018;
- The $537 million net long-lived asset impairment charge to Bison's current carrying value; and
- the $59 million impairment charge related to Tuscarora's goodwill;

We believe these items are 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 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 year ended December 31, 2018, less $20 million (Class B Distribution) (2017 and 2016 – less $20 million).

For the year ended December 31, 2018, the Class B Distribution was further reduced by 35 percent, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018 (Class B Reduction). The Class B Reduction was implemented during the first quarter of 2018 following the Partnership's common unit distribution reduction of 35 percent and will apply to any calendar year during which distributions payable in respect of common units for such calendar year do not equal or exceed $3.94 per common unit. The Class B Reduction was not applicable during 2017 and 2016.

Adjusted earnings and Adjusted earnings per common unit exclude the impact of the $97 million of Bison contract buy-out proceeds and $596 million of impairment charges incurred during the year ended December 31, 2018 on our net income on a whole and per common unit basis, respectively.

Distributable cash flow, EBITDA, Adjusted EBITDA, Adjusted earnings and Adjusted earnings per common unit 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 (Loss) 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)*	**2018**	2017	2016[a]
Net income (loss)	**(165)**	263	263
Add:			
Interest expense[b]	**94**	84	73
Depreciation and amortization	**97**	97	96
Income taxes	**1**	1	1
EBITDA	**27**	445	433
Add:			
Impairment of goodwill	**59**	–	–
Impairment of long-lived assets	**537**	–	–
Bison contract buyout	**(97)**	–	–
ADJUSTED EBITDA	**526**	445	433
Add:			
Distributions from equity investments[c]			
Northern Border	**85**	82	91
Great Lakes	**66**	38	34
Iroquois	**56[d]**	41[d]	–
	207	161	125
Less:			
Equity earnings:			
Northern Border	**(68)**	(67)	(69)
Great Lakes	**(59)**	(31)	(28)
Iroquois	**(46)**	(26)	–
	(173)	(124)	(97)
Less:			
Equity AFUDC	**(1)**	–	–
Interest expense[b]	**(94)**	(84)	(73)
Income taxes	**(1)**	(1)	(1)
Distributions to non-controlling interests[e]	**(20)**	(14)	(18)
Distributions to TransCanada as PNGTS' former parent[f]	**–**	(2)	(6)
Maintenance capital expenditures[g]	**(36)**	(38)	(16)
	(152)	(139)	(114)
Total Distributable Cash Flow	**408**	343	347
General Partner distributions declared[h]	**(4)**	(18)	(12)
Distributions allocable to Class B units[i]	**(13)**	(15)	(22)
Distributable Cash Flow	**391**	310	313

[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 13 and 20, 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' 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 and includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $10 million and $8 million for the year ended December 31, 2018 and the seven months ended December 31, 2017, respectively. (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, 2018 did not include any incentive distributions (2017 – $12 million; 2016 – $7 million).

[(i)] Distributions allocable to the Class B units is based on 30 percent of GTN's distributable cashflow during the current reporting period, but declared and paid in the subsequent reporting period.

Year Ended December 31, 2018 Compared with the Year Ended December 31, 2017

Our EBITDA was $418 million lower in 2018 compared to 2017 due to the goodwill impairment of $59 million for Tuscarora and the long-lived asset impairment for Bison of $537 million, partially offset by the additional $97 million in revenue recognized for the Bison contract buyout. Our Adjusted EBITDA was higher by $81 million compared to 2017 as a result of higher equity earnings and an overall increase in revenues in 2018. Refer to "Results of Operations" for more details.

Our distributable cash flow for the twelve months ended December 31, 2018 was $81 million higher compared to the twelve months ended December 31, 2017 due to the net effect of:

- higher Adjusted EBITDA from GTN, PNGTS and North Baja due to an increase in their revenues generated during the twelve months ended December 31, 2018 as described in the "Results of Operations" section;
- four quarters of distributions received from Iroquois during the twelve months ended December 31, 2018 compared to three quarters of distributions received during the previous period (ownership of 49.34 percent was effective June 1, 2017);
- higher financing costs as a result of additional debt incurred to partially finance the 2017 Acquisition;
- higher distributions from Great Lakes due to the increase in its revenue generated during the twelve months ended December 31, 2018 from higher short-term services sold during the year and the elimination of Great Lakes' revenue sharing mechanism that began in 2018 as part of Great Lakes rate settlement in 2017;
- higher distributable cash flow from Northern Border primarily due to an overall decrease in its system integrity maintenance capital expenditures in 2018;
- reduction in declared distributions which did not result in any IDR allocation to our General Partner during the current period; and

- lower distributions allocated to the Class B units as a result of the Class B Reduction, which was directly related to the reduction in distributions declared for the common units.

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.

Contractual Obligations

The Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2018 included the following:

		Payments Due by Period				
(unaudited) *(millions of dollars)*	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Year Ended December 31, 2018
TC PipeLines, LP						
Senior Credit Facility due 2021	40	–	40	–	–	3.14%
2013 Term Loan Facility due 2022	500	–	–	500	–	3.23%
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	35	35	–	–	–	2.93%
PNGTS						
Revolving Credit Facility due 2023	19	–	–	19	–	3.55%
Tuscarora						
Unsecured Term Loan due 2020	24	1	23	–	–	3.10%
North Baja						
Unsecured Term Loan due 2021	50	–	50	–	–	3.54%
Partnership (TC PipeLines, LP and its subsidiaries)						
Interest on Debt Obligations[b]	532	89	159	100	184	
Operating Leases	5	1	1	1	2	
	2,655	126	723	620	1,186	

[a] Fixed Rate debt

[b] Future interest payments on our fixed rate debt are based on scheduled maturities. Future interest payments on floating rate debt are estimated using debt levels and interest rates at December 31, 2018 and are therefore subject to change beyond 2018.

Additional information regarding the Partnership's debt can be found under Note 9-Debt and Credit Facilities within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations as of December 31, 2018 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	54	20	34	–	–
Other commitments[b]	50	2	5	5	38
	369	22	304	5	38

[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 $2 million as of December 31, 2018 in connection with various pipeline, metering and overhaul projects.

At December 31, 2018, the aggregate estimated fair value of Northern Border's long-term debt was approximately $286 million (2017 – $294 million). In 2018, interest expense related to the senior notes was $19 million (2017 – $19 million; 2016 – $23 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, 2018, 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, 2018, $15 million was outstanding on this facility. 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, 2018 was 3.48 percent (2017 – 2.12 percent). At December 31, 2018, 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, 2018 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
9.09% series Senior Notes due 2016 to 2021	30	10	20	–	–
6.95% series Senior Notes due 2019 to 2028	110	11	22	22	55
8.08% series Senior Notes due 2021 to 2030	100	–	10	20	70
Interest payments on debt	100	18	31	22	29
	340	39	83	64	154

[a] Represents 100 percent of Great Lakes' contractual obligations.

Great Lakes has commitments of $2 million as of December 31, 2018 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 $129 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2018 (2017 – $139 million). Great Lakes was in compliance with all of its financial covenants at December 31, 2018.

The aggregate estimated fair value of Great Lakes' long-term debt was $288 million at December 31, 2018 (2017 – $335 million). The aggregate annual required repayment of senior notes is $21 million for each year 2019 and 2020, $31 million for 2021, $21 million for 2022 and $21 million for 2023. Aggregate required repayments of senior notes thereafter total $125 million. In 2018, interest expense related to Great Lakes' senior notes was $19 million (2017 – $21 million; 2016 – $22 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, 2018 and 2017, Great Lakes has an outstanding receivable from this arrangement amounting to $36 million and $64 million, respectively.

Summary of Iroquois' Contractual Obligations

Iroquois' contractual obligations as of December 31, 2018 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	35	6	7	8	14
Interest payments on debt	24	13	7	2	2
Transportation by others[b]	12	3	6	3	–
Operating leases	6	1	2	1	2
Pension contributions[c]	1	1	–	–	–
	368	164	172	14	18

[a] Represents 100 percent of Iroquois' contractual obligations.

[b] Rates are based on known 2019 levels. Beyond 2019, demand rates are subject to change.

[c] Pension contributions cannot be reasonably estimated by Iroquois beyond 2019.

Iroquois has commitments of $2 million as of December 31, 2018 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 21, 2019, Iroquois has distributed approximately $36.7 million of the expected

$57.6 million, of which our proportionate share was approximately $18.1 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, 2018, the debt/capitalization ratio was 48.6 percent and the debt service coverage ratio was 6.36 times, therefore, Iroquois was not restricted from making 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 after providing for Class B distributions based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its IDRs and effective two percent general partner interest through December 31, 2018 and two percent general partner interest thereafter and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The percentage interest distributions to the General Partner illustrated below that are in excess of its two percent general partner interest represent 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%

Further information regarding our distributions can be found under Note 15-Cash Distributions within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference

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 rate-making 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 rate-making 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 rate-making 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. Due to the impairment recognized on Bison during the fourth quarter of 2018 (discussed in more detail below under "Long Lived Assets"), ASC 980 on Bison was discontinued as the future recovery of costs is no longer probable. The impact of ASC 980 discontinuance on Bison was immaterial to the consolidated results of the Partnership.

As of December 31, 2018, our equity investees have regulatory assets amounting to $14 million (2017 – $17 million).

As of December 31, 2018, our equity investees have regulatory liabilities amounting to $34 million (2017 – $28 million).

At December 31, 2018, the Partnership had $2 million regulatory assets reported on the balance sheet as part of other current assets and $2 million regulatory liabilities reported on the balance sheet as part of accounts payable and accrued liabilities both representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers on a continued basis (2017 – nil). As of December 31, 2018, the Partnership had long-term regulatory liabilities of $27 million largely related to estimated costs associated with future removal of transmission and gathering facilities or allowed by FERC to be collected in depreciation rates (also known as "negative salvage") (2017 – $26 million).

Impairment of Goodwill, Long-Lived Assets and 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 can initially assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired and if we conclude that it is not more likely than not that fair value of the reporting unit is greater than its carrying value, we will then perform the quantitative goodwill impairment test. We can also can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Partnership compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

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.

Tuscarora

In the fourth quarter of 2018, Tuscarora initiated its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its maximum rates. In connection with our annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, which included estimates related to discount rates and earnings multiples. In doing so, we incorporated the expected impact of Tuscarora's regulatory approach in response to the 2018 FERC Actions, in which it elected to make a limited NGA Section 4 filing to reduce its maximum rates and eliminate its deferred income tax balances previously used for rate setting. Additionally, we have considered in our overall conclusion the outcome of the January 2019 settlement-in-principle reached by Tuscarora with its customers.

Our analysis resulted in the estimated fair value of Tuscarora not exceeding its carrying value, including goodwill. The fair value was measured using a discounted cash flow approach whereby the expected cashflows were discounted using a risk adjusted discount rate to determine fair value.

As a result, we recorded a goodwill impairment charge amounting to $59 million against Tuscarora's goodwill balance of $82 million. The non-cash impairment charge was recorded in the Impairment of goodwill line on the Consolidated statement of operations and reduced our total consolidated goodwill balance from $130 million to $71 million. There is a risk that adverse changes in our key assumptions could result in an additional future impairment on Tuscarora's remaining goodwill of $23 million.

At December 31, 2018, we have not identified an impairment on the $48 million of goodwill related to the North Baja acquisition.

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 the same factors we consider in our annual impairment test of goodwill such as:

- 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.

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 consolidated statement of operations.

Bison

During the fourth quarter of 2018, Bison received an unsolicited offer from a customer regarding the termination of its contract, which represented approximately 60 percent of Bison's contracted revenues. Bison and the customer mutually agreed to terms which included a cash payment to Bison of $95.4 million in December 2018 in exchange for the termination of all its contract obligations with Bison. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison in exchange for a lumpsum payment to Bison of approximately $2.0 million in December 2018. At the completion of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018 and the cash payments were used by the Partnership, together with other cash to pay in full its 2015 Term Loan Facility.

As disclosed under Part 1, Item 1. Business – Customers, Contracting and Demand section, natural gas is currently not flowing on Bison as a result of the relative cost advantage of WCSB- and Bakken – sourced gas versus Rockies production. Since its inception in January 2011, Bison has not experienced a decrease in its revenue as its original ten-year contracts included ship-or-pay terms that resulted in payment to Bison regardless of gas flows. With the advanced payments to Bison and related cancellation of the above contracts, Bison's future revenue will be reduced by approximately $47 million per year in 2019 and 2020, respectively. The customer contract cancellations coupled with the persistence of unfavorable market conditions which have inhibited system flows have prompted management to re-evaluate the carrying value of Bison's long-lived assets.

Although the Partnership continues to evaluate alternatives for recontracting or redevelopment of Bison, management is currently unable to quantify the future cash flows of a viable operating plan beyond the remaining customer contracts' expiry in January 2021, and accordingly the Partnership evaluated for impairment the carrying value of its property, plant and equipment on Bison at December 31, 2018. The Partnership will continue to maintain Bison to stand ready for redevelopment and has concluded that the remaining obligations of Bison, primarily in the form of ad valorem tax obligations and operating and maintenance costs, exceed the net cash inflows that management currently considers probable and estimable.

Based on these factors, during the fourth quarter of 2018, the Partnership recognized a non-cash impairment charge of $537 million relating to the remaining carrying value of Bison's property, plant and equipment after determining that it was no longer recoverable. The non-cash charge was recorded under the Impairment of long-lived assets line on the Consolidated statement of operations. Bison's remaining contracts will continue through January of 2021, with annual revenues of $32.3 million and $30.7 million in 2019 and 2020, respectively.

As of December 31, 2018, there were no indicators of impairment on the rest of our 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 include the same factors we consider in our annual impairment test of goodwill such as:

- 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.

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.

Great Lakes
At December 31, 2018, the equity method goodwill balance related to Great Lakes amounted to $260 million (December 31, 2017- $260 million). The equity method goodwill relates to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes and is the difference between the carrying value of our investment in Great Lakes and the underlying equity in Great Lakes' net assets.

During the fourth quarter of 2018, Great Lakes finalized its regulatory approach in response to the 2018 FERC Actions and elected to make a limited NGA section 4 filing with FERC to reduce its maximum rates and eliminate its tax allowance and deferred income tax balances previously used for rate setting. As a result of this action, and because the estimated fair value of our investment in Great Lakes exceeded its carrying value by less than 10 percent in its 2017 valuation, we performed a quantitative test to determine if there was other than temporary decline in Great Lakes' fair value. At December 31, 2018, the estimation of the fair value of our remaining equity investment in Great Lakes was completed and we concluded the fair value of our investment in Great Lakes exceeded its carrying value by more than 10 percent.

The assumptions we used in the analysis related to the estimated fair value of our equity investment in Great Lakes included expected results from its limited NGA Section 4 filing with FERC, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment, which includes estimates related to discount rates and earnings multiples. Although our analysis indicated that 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.

As of December 31, 2018, no impairment charge has been recorded related to any of our other equity investments.

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 current 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, 2018, the Partnership's interest rate exposure resulted from our floating rate Senior Credit Facility, 2013 Term Loan Facility, GTN's Unsecured Term Facility, North Baja's Unsecured Term Facility, PNGTS's Revolving Credit Facility and Tuscarora's Unsecured Term Facility, under which $168 million, or eight percent, of our outstanding debt was subject to variability in LIBOR interest rates (2017- $435 million or 18 percent).

As of December 31, 2018, 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 3.26 percent. If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2018, 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 $2 million.

As of December 31, 2018, $15 million, or 6 percent of Northern Border's outstanding debt was at floating rates (2017 – $15 million or 6 percent). If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at December 31, 2018, Northern Border's annual interest expense (decrease) and its net income would decrease (increase) by approximately nil.

GTN's Unsecured Senior Notes, Northern Border's and Iroquois' Senior Notes, and all of Great Lakes' 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, as it currently does 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. For details regarding our current interest swaps and other agreements related to mitigation of impact on changes in interest rates, see Note 20- Fair Value Measurements within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference.

COMMODITY PRICE RISK

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, 2018, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2018, we had a credit risk concentration on one of our customers and the amount owed is approximately 10 percent of our trade accounts receivable and consolidated revenues. Refer to Note 17-Transactions with major customers within Part IV, Item 15. "Exhibits and Financial Statement Schedules" for more information. See also Part I, Item 1. "Business" Customers, Contracting and Demand section for more information on certain customers.

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, 2018, the Partnership had a Senior Credit Facility of $500 million maturing in 2021 with an outstanding balance on this facility of $40 million. At December 31, 2018, PNGTS has a $125 million Revolving Credit Facility maturing in 2023 and has an outstanding balance of $19 million and finally, at December 31, 2018, Northern Border had a committed revolving bank line of $200 million maturing in 2020 and $15 million was drawn. The Partnership's Senior Credit Facility, PNGTS' Revolving Credit Facility and the Northern Border's Credit Facility have accordion features for additional capacity of $500 million, $50 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 year ended December 31, 2018, 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, 2018 at providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. No material weaknesses were identified.

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 as of February 21, 2019. Directors are appointed by the General Partner's sole stockholder to serve one-year terms or until their successors are 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
Stanley G. Chapman, III	53	Chair and Director
Jack F. Stark	68	Independent Director
Malyn K. Malquist	66	Independent Director
Walentin (Val) Mirosh	73	Independent Director
Nathaniel A. Brown	42	President, Principal Executive Officer and Director
Nadine E. Berge	46	Director
Sean M. Brett	53	Director
Janine M. Watson	49	Vice-President and General Manager
Nancy F. Priemer	60	Vice-President, Taxation
Jon A. Dobson	52	Secretary
William C. Morris	56	Principal Financial Officer, Vice-President and Treasurer

Mr. Chapman has served as a director and Chair of the Board of Directors of the General Partner since January 1, 2019. Mr. Chapman's principal occupation is Executive Vice-President and President, U.S. Natural Gas Pipelines of TransCanada, a position he has held since April 2017. He is responsible for all pipeline operations and commercial activities across TransCanada's FERC-regulated transmission and storage assets as well as its U.S. unregulated midstream business. Mr. Chapman joined TransCanada as part of its acquisition of the Columbia Pipeline Group ("Columbia") in July 2016 and served as Senior Vice President and General Manager of TransCanada's FERC-regulated US natural gas pipeline business from July 2016 to April 2017. Prior to joining TransCanada, Mr. Chapman held several positions at Columbia from December 2011 to July 2016, most recently as Executive Vice-President and Chief Commercial Officer. Before joining Columbia, Mr. Chapman held various positions of increasing responsibility with El Paso Corp and Tenneco Energy and was responsible for various marketing and commercial operations, as well as supply, regulatory, business development and optimization activities. His and his industry knowledge, management experience and leadership skills are highly valuable in developing and implementing our business strategies and assessing accompanying risks.

Mr. Stark has served as a director and member of the audit and conflicts committee of the board of directors of the General Partner since 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 the Chief Financial Officer of BrightSource Energy Inc., a provider of technology for use in large-scale solar thermal power plants, 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. Prior to May 2007, Mr. Stark held chief financial officer positions at Itron Inc., Silicon Energy Corporation and GATX Capital as well as senior management roles at PG&E Corporation for more than 20 years. Mr. Stark currently serves as a director, Chairman of the Board and member of the audit committee of the board of directors of Washington Gas Light Company, a regulated natural gas utility. He also serves on the board of directors of AltaGas Services (U.S.) Inc. (ASUS), a wholly-owned subsidiary of AltaGas Ltd., and AltaGas Utility Holdings (U.S.) Inc., a wholly owned subsidiary of ASUS. 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, finance, 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.

Mr. Malquist has served as a director, Chair of the audit committee and member of the conflicts committees of the board of directors of the General Partner since 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 September 2002 to March 2009, Mr. Malquist held various senior executive positions with Avista Corporation (Avista), an energy production, transmission and distribution company, including Senior Vice President from September 2002 to May 2006, Executive Vice President from May 2006 to March 2009, Chief Financial Officer from November 2002 to September 2008 and Treasurer from February 2004 to January 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 has served as a director and member of the audit and conflicts committees of the board of directors of the General Partner since 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 (NOVA), a commodity chemicals and plastics company. From July 2003 to April 2008, Mr. Mirosh was President of Olefins and Feedstocks, a division of NOVA. Prior to joining NOVA, Mr. Mirosh was a partner at Macleod Dixon law firm. Mr. Mirosh is also a director of 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 are complemented by an engineering educational background and legal experience, are beneficial to the Board of Directors and Audit Committee on a full range of business, financial, technical and professional matters.

Mr. Brown has served as President, Principal Executive Officer and a director of the General Partner since May 1, 2018. He previously served as Controller and Principal Financial Officer of the General Partner from May 2014 to May 2018. His principal occupation is Vice-President, U.S. Natural Gas Pipelines Financial Services of TransCanada, a position he has held since February 2018. In this position, he is responsible for the accounting, financial reporting, planning and budgeting of TransCanada's U.S. natural gas pipelines. Mr. Brown also served as Director of Financial Services for TransCanada's U.S. Pipelines from May 2014 to February 2018 and Manager of Accounting for TransCanada's U.S. Pipelines West from November 2009 to May 2014. 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. Berge has been a director of the General Partner since May 2018. Ms. Berge's principal occupation is Director, Corporate Compliance and Legal Operations with TransCanada, a position she has held since December 2014. Ms. Berge has served in several positions of increasing responsibility in the legal department since joining TransCanada in May 2005. Ms. Berge is responsible for directing the corporate compliance area across Canada, the US and Mexico, as well as leadership of operational matters for the TransCanada legal department in all three jurisdictions. Prior to joining TransCanada, Ms. Berge spent five years practicing law in the area of energy regulation. Ms. Berge brings valuable legal skills and experience to the Board of Directors.

Mr. Brett has served as a director of the General Partner since May 2018. Mr. Brett's principal occupation is Senior Vice-President, Energy with TransCanada, a role he has held since January 2019 and in which he is responsible for all aspects of TransCanada's Energy business, including strategy, commercial, business development, projects and operations. Mr. Brett joined TransCanada in March 1997 and held several positions of increasing responsibility prior to his current role, including Vice-President, Power and Storage from June 2018 to January 2019, Vice-President, Risk Management from August 2015 to June 2018 and Vice President and Treasurer from July 2010 to August 2015. Mr. Brett also previously served as Vice President, Commercial Operations of the General Partner from December 2009 to July 2010 and as Treasurer of the General Partner from January 2007 to December 2008. Mr. Brett's familiarity with the Partnership and TransCanada and his breadth of experience are highly valuable to the Board of Directors and are useful in assessing our business strategies and accompanying risks.

Ms. Watson has served as Vice-President and General Manager for the General Partner since October 2015. Her principal occupation is Director, LP Management & Pricing for TransCanada, a position she has held since October 2015. Ms. Watson joined TransCanada in 1997 and has served in progressively senior positions in the natural gas pipeline and energy business segments of TransCanada prior to her current position, most recently as Associate General Counsel, Energy Law. Prior to joining TransCanada, Ms. Watson was an attorney at the Calgary office of McCarthy Tétrault and clerked at the Alberta Court of Appeal.

Ms. Priemer has served as Vice-President, Taxation of the General Partner since February 2016. Her principal occupation is Director, U.S. Natural Gas Pipelines Taxation of TransCanada, in which role she leads the U.S. tax group and is responsible for providing tax administration, tax planning, regulatory and accounting support for TransCanada's U.S. pipeline subsidiaries. Ms. Priemer joined TransCanada in 1998 and served as Tax Director of a TransCanada subsidiary until she was appointed Director, Natural Gas Pipelines Taxation in July 2009. Prior to joining TransCanada, Ms. Priemer spent eighteen years in public accounting and private industry.

Mr. Dobson has served as appointed Secretary of the General Partner since May 2014, prior to which he served as Assistant Secretary of the General Partner from April 2012. Mr. Dobson's principal occupation is Director, U.S. Governance 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 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 has served as Vice-President, Principal Financial Officer and Treasurer of the General Partner since February 2018. Mr. Morris previously served as Vice President and Treasurer of the General Partner from November 2017 to February 2018 and as Treasurer of the General Partner from 2012 to November 2017. Mr. Morris' principal occupation is Director, Finance and Assistant Treasurer of TransCanada, a position he has held since November 2015. In this role, he is responsible for the development, execution and monitoring of TransCanada's financing strategy. Mr. Morris joined TransCanada in 1996 and has held various positions of increasing responsibility, including manager, Risk Management, Director of Risk Management, and Director, Corporate Finance. Prior to joining TransCanada, Mr. Morris spent 12 years in 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 April 2, 2018.

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.tcpipelineslp.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 Audit 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 Audit 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 Audit 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 non-management 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 non-management 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 Partnership's 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 2018.

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.transcanada.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 costs allocated to us for managerial, administrative and operational support provided by TransCanada and its affiliates, including our General Partner. We 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:

Nadine E. Berge
Sean M. Brett
Nathaniel A. Brown
Stanley G. Chapman, III
Malyn K. Malquist
Walentin (Val) Mirosh
Jack F. Stark

The following table summarizes the allocation percentages and amounts of the base salary and benefits charged to the Partnership in 2018, 2017 and 2016 for our President and Principal Executive Officers during 2018, Vice President, Principal Financial Officer and Treasurer and other executive officers of our General Partner for whom the salaries and benefits allocations to us exceeded $100,000.

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)
Nathan A. Brown[b]	**2018**	**35%**	**156,986**
President and Principal Executive Officer	2017	35%	121,737
	2016	35%	112,663
Brandon Anderson[c]	**2018**	**30%**	**71,524**
President and Principal Executive Officer	2017	30%	209,135
	2016	30%	199,920
Janine Watson[e]	**2018**	**50%**	**182,504**
Vice-President and General Manager	2017	50%	170,244
	2016	50%	155,782
William C. Morris[d][e]	**2018**	**50%**	**169,280**
Vice-President, Principal Financial Officer and Treasurer	2017	50%	163,891
	2016	50%	152,956
Jon A. Dobson	**2018**	**60%**	**268,024**
Secretary	2017	60%	253,793
	2016	60%	239,226

[a] Amounts presented are the base salary and benefits rate allocations from TransCanada to the Partnership for the year indicated based on percentage of the applicable officer's time devoted to the Partnership.

[b] Appointed as President and Principal Executive Officer effective May 1, 2018. The total compensation allocated to the Partnership in 2018 includes salary as Controller and Principal Financial Officer of the Partnership from January 1, 2018-April 30, 2018.

[c] Appointed as President and Principal Executive Officer effective January 1, 2016 and served until April 30, 2018.

[d] Appointed as Vice-President, Principal Financial Officer and Treasurer effective May 1, 2018. The total compensation allocated to the Partnership in 2018 includes salary as Vice-President and Treasurer of the Partnership from January 1, 2018-April 30, 2018.

[e] 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, 2018 *(in dollars)*	Fees Earned or Paid in Cash	Deferred Share Unit Awards[b]	Total
Malyn K. Malquist[c]	98,500	70,000	168,500
Jack F. Stark[d]	98,500	70,000	168,500
Walentin (Val) Mirosh[e]	83,500	70,000	153,500

[(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 employee directors. 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 2018 under the DSU Plan. All of the DSUs granted to Messrs. Malquist, Stark and Mirosh were outstanding at December 31, 2018.

At December 31, 2018, Mr. Malquist, Mr. Stark and Mr. Mirosh held 16,553, 24,573 and 17,370 DSUs, respectively. The fair market value of the DSUs held by Mr. Malquist, Mr. Stark and Mr. Mirosh at December 31, 2018 was $531,682, $789,292 and $557,916, 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 1,225 DSUs, Mr. Stark was credited 1,876 DSUs and Mr. Mirosh was credited 1,291 DSUs. All DSUs credited during 2018 were outstanding at December 31, 2018.

[(c)] Chair of the Audit Committee. Cash payments to Mr. Malquist include the $55,000 annual cash retainer, $15,000 Audit Committee Chair retainer and $28,500 of meeting attendance fees.

[(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 $28,500 of meeting attendance fees.

[(e)] Cash payments to Mr. Mirosh include the $55,000 annual cash retainer and $28,500 of meeting attendance fees.

Cash Compensation

In 2018, 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 Deferred Share Units 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. 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 cash 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 2018, as part of the retainer fee, each independent director received quarterly automatic grants of DSUs valued at $17,500 each for a total annual grant value of $70,000.

At the time of grant, the value of a DSU is equal to the market value of one common unit of the Partnership at the time the DSU is credited to the independent director's account. The value of a DSU when redeemed is equivalent to the market value of one common unit of the Partnership 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 purchased in the open market through a broker at their option.

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

The following table sets forth information as of February 20, 2019 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	15,014,832	21.06	–	–
ALPS Advisors, Inc.[(f)] 1290 Broadway, Suite 1100 Denver, CO 80203	5,385,639	7.55	–	–
First Trust Portfolios LP[(g)] 120 East Liberty Drive, Suite 400 Wheaton, Illinois 60187	5,416,786	7.60		
Energy Income Partners, LLC[(h)] 10 Wright Street Westport, Connecticut 06880	6,877,079	9.6		
Malyn K. Malquist[(i)]	17,906	*	–	–
Jack F. Stark[(j)]	25,387	*	–	–
Walentin (Val) Mirosh[(k)]	17,741	*	995	*
Stanley G. Chapman, III[(l)]	–	–	109,408	*
Nadine E. Berge	–	–	–	–
Sean M. Brett[(m)]	–	–	73,301	*
Nathaniel A. Brown[(n)]	–	–	2,474	*
Jon A. Dobson[(o)]	–	–	376	*
William C. Morris[(p)]	–	–	22,038	*
Janine M. Watson[(q)]	–	–	1,067	*
Directors and Executive officers as a Group[(r)] (10 people)	61,034	*	209,659	*

(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 a two percent general partner interest of the Partnership.

[e] Based on a Schedule 13G/A filed with the SEC on January 18, 2019 by OppenheimerFunds, Inc. In this Schedule 13G/A, OppenheimerFunds, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 15,014,832 common units.

[f] Based on a Schedule 13G/A filed with the SEC on February 4, 2019 by ALPS Advisors, Inc. In this Schedule 13G/A ALPS Advisors, Inc. disclaims beneficial ownership, and has shared power to vote and to dispose of the 5,385,639 common units.

[g] Based on Schedule 13G/A filed with the SEC on January 28, 2019 jointly by First Trust Portfolios LP, First Trust Advisors L.P. and The Charger Corporation. In this Schedule 13G, First Trust Advisors L.P. and The Charger Corporation have shared power to vote 5,410,451 common units and shared power to dispose of 5,416,786 common units, and First Trust Portfolios LP, First Trust Advisors L.P. and The Charger Corporation. disclaim beneficial ownership of all of said common units.

[h] Based on Schedule 13G/A filed with the SEC on February 14, 2019 by Energy Income Partners, LLC. In this Schedule 13G/A, Energy Income Partners LLC has shared power to vote and to dispose of the 6,877,079 common units.

[i] Includes 16,906 DSUs and 1,000 common units of the Partnership.

[j] Includes 25,097 DSUs and 290 common units of the Partnership.

[k] Includes 17,741 DSUs and 995 TransCanada common shares.

[l] Includes 102,731 options exercisable within 60 days for TransCanada common shares and 6,677 TransCanada common shares held directly by Mr. Chapman.

[m] Includes 57,100 options exercisable within 60 days for TransCanada common shares, 3,107 TransCanada common shares held in his Employee Share Savings Plan accounts, 4494 TransCanada common shares held directly and 8,600 TransCanada shares held by Mr. Brett's mother, of which he disclaims beneficial ownership.

[n] Includes 2,474 options exercisable within 60 days for TransCanada common shares.

[o] Includes 376 TransCanada common shares held in his TransCanada 401K and Savings Plan account.

[p] Includes 9,431 TransCanada common shares held in his Employee Share Savings Plan account and 12,607 TransCanada common shares held jointly with his spouse.

[q] Includes 1,067 TransCanada common shares held in her Employee Share Savings Plan account.

[r] Includes 59,744 DSUs and 1,290 common units of the Partnership, 12,166 TransCanada common shares held directly, 12,607 TransCanada common shares held with a spouse, 162,305 options exercisable within 60 days for TransCanada common shares, 8,600 TransCanada common shares owned by immediate family members of which beneficial ownership of such common shares is disclaimed, and 13,605 TransCanada common shares held in the TransCanada Employee Share Savings Plan and 376 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 20, 2019, subsidiaries of TransCanada own 17,084,831, or approximately 24 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 a 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 8, 11, 14 and 15 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 and adjustments, after the Class B reduction.
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, 2018.

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, 2018 and 2017, Great Lakes had outstanding receivables from this arrangement amounting to $36 million and $64 million, respectively.

Transportation Agreements

Great Lakes and PNGTS have transportation agreements with TransCanada and affiliates. Refer to Note 17 within Part IV, Item 15. "Exhibits and Financial Statement Schedules", which information is incorporated herein by reference.

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 Note 8 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" which information is incorporated herein by reference.

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, 2018, 2017 and 2016 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2018 and 2017 are summarized in Note 18 within Part IV, Item 15. "Exhibits and Financial Statement Schedules" which information is incorporated herein by reference.

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)*	**2018**	2017	2016
Audit Fees[(a)]	**1,165**	861[(b)]	1,071
Audit Related Fees	**–**	–	–
Tax Fees[(c)]	**–**	–	–
All Other Fees	**–**	–	–
Total	**1,165**	861	1,071

(a) $50 thousand of the 2018 audit fees related to ATM equity financing (2017 – $200 thousand and 2016 – $320 thousand).

(b) $65 thousand of the 2017 audit fees related to issuance of senior unsecured notes.

(c) The Partnership did not engage its external auditors for any tax or other services in 2018, 2017 or 2016.

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 U.S. 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 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).
2.1.1*	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).
2.2*	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*	Certificate of Limited Partnership of TC PipeLines, LP (Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, filed on December 30, 1998).
3.2*	Fourth Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated December 31, 2018 (Incorporated by reference from Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed January 2, 2019).
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).

No.	Description
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).
10.1*	Third Amended and Restated Revolving Credit and Term Loan Agreement, dated as of November 10, 2016, by and among TC PipeLines, LP, the Lenders, and SunTrust Bank, as administrative agent for the Lenders (Incorporated by reference to Exhibit 10.21 to TC PipeLines, LP's Form 10-K filed on February 28, 2017)
10.1.1*	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).
10.2*	Term Loan Agreement, dated as of July 1, 2013, between TC PipeLines, LP and the lenders (Incorporated by reference to Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on July 3, 2013).
10.2.1*	First Amendment to Term Loan Agreement, dated as of November 10, 2016, by and among TC PipeLines, LP, the Required Lenders and SunTrust Bank, as administrative agent for the Lenders (Incorporated by reference to Exhibit 10.11.1 to TC PipeLines, LP's Form 10-K filed on February 28, 2017).
10.2.2*	Second Amendment to TC PipeLines, LP's July 1, 2013 Term Loan Agreement, dated September 29, 2017 (Incorporated by reference to Exhibit 99.1 to TC PipeLines, LP's Form 8-K filed October 3, 2017)
10.3*	Revolving Credit Agreement dated as of April 5, 2018, between Portland Natural Gas Transmission System and SunTrust Bank as administrative agent (Incorporated by reference from Exhibits 10.1 to TC PipeLines, LP's Form 10-Q filed May 2, 2018).
10.4*	Transportation Service Agreement FT19214 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 16, 2018 (Incorporated by reference from Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2018).
10.5*	Transportation Service Agreement FT19215 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 16, 2018 (Incorporated by reference from Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed August 3, 2018).
10.6*	Amended Precedent Agreement by and between Portland Natural Gas Transmission System and TransCanada PipeLines Limited (Incorporated by reference from Exhibit 10.3 to TC PipeLines, LP's Form 10-Q filed August 3, 2018).
10.8*	Amended Financial Assurances Agreement by and between Portland Natural Gas Transmission System and TransCanada PipeLines Limited (Incorporated by reference from Exhibit 10.4 to TC PipeLines, LP's Form 10-Q filed August 3, 2018).
10.8*	Termination Agreement for Rate Schedule FT-1 Service Agreement by and between Bison Pipeline LLC and Tenaska Marketing Ventures (Incorporated by reference from Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed November 26, 2018).
10.9*	Contribution Agreement, dated December 31, 2018 (Incorporated by reference from Exhibit 10.1 to TC PipeLines LP's Form 8-K filed January 3, 2019)

No.	Description
10.10	Term Loan Agreement dated as of December 19, 2018, between North Baja Pipeline, LLC and MUFG Bank, LTD as administrative agent
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.
23.4	Consent of Blum, Shapiro & Company, P.C. with respect to the financial statements of Iroquois Gas Transmission System, L.P.
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Transportation Service Agreement FT18759 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 01, 2018. (Incorporated by reference from Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed May 2, 2018)
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 2019.

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

By: /s/ Nathaniel A. Brown

Nathaniel A. Brown
President
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ William C. Morris

William C. Morris
Vice President and Treasurer
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/ Stanley Chapman Stanley Chapman	Chair	February 21, 2019
/s/ Nathaniel A. Brown Nathaniel A. Brown	Principal Executive Officer and President	February 21, 2019
/s/ William C. Morris William C. Morris	Principal Financial Officer, Vice President and Treasurer	February 21, 2019
/s/ Nadine E. Berge Nadine E. Berge	Director	February 21, 2019
/s/ Sean M. Brett Sean M. Brett	Director	February 21, 2019
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 21, 2019
/s/ Jack F. Stark Jack F. Stark	Director	February 21, 2019
/s/ Malyn K. Malquist Malyn K. Malquist	Director	February 21, 2019

TC PIPELINES, LP
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, 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 21, 2019

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	**2018**	2017
ASSETS		
Current Assets		
Cash and cash equivalents	**33**	33
Accounts receivable and other (Note 21)	**48**	42
Inventories	**8**	8
Other	**8**	7
	97	90
Equity investments (Note 5)	**1,196**	1,213
Property, plant and equipment, net (Note 7)	**1,529**	2,123
Goodwill (Note 4)	**71**	130
Other assets	**6**	3
TOTAL ASSETS	**2,899**	3,559
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**36**	31
Accounts payable to affiliates (Note 18)	**6**	5
Accrued interest	**12**	12
Distributions payable	**–**	1
Current portion of long-term debt (Note 9)	**36**	51
	90	100
Long-term debt (Note 9)	**2,072**	2,352
Deferred state income taxes (Note 24)	**9**	10
Other liabilities (Note 10)	**29**	29
	2,200	2,491
Partners' Equity (Note 11)		
Common units	**462**	824
Class B units	**108**	110
General partner	**13**	24
Accumulated other comprehensive income (loss) (AOCI) (Note 12)	**8**	5
Controlling interests	**591**	963
Non-controlling interest	**108**	105
	699	1,068
TOTAL LIABILITIES AND PARTNERS' EQUITY	**2,899**	3,559

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

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

TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (millions of dollars except per common unit amounts)	**2018**	2017	2016[a]
Transmission revenues, net (Note 6)	**549**	422	426
Equity earnings (Note 5)	**173**	124	97
Impairment of long-lived assets (Note 7)	**(537)**	–	–
Impairment of goodwill (Note 4)	**(59)**	–	–
Operation and maintenance expenses	**(67)**	(67)	(58)
Property taxes	**(28)**	(28)	(27)
General and administrative	**(6)**	(8)	(7)
Depreciation	**(97)**	(97)	(96)
Financial charges and other (Note 13)	**(92)**	(82)	(71)
Net income (loss) before taxes	**(164)**	264	264
Income taxes (Note 24)	**(1)**	(1)	(1)
Net Income (loss)	**(165)**	263	263
Net income attributable to non-controlling interests	**17**	11	15
Net income (loss) attributable to controlling interests	**(182)**	252	248
Net income (loss) attributable to controlling interest allocation (Note 14)			
Common units	**(191)**	219	211
General Partner	**(4)**	16	11
TransCanada and its subsidiaries	**13**	17	26
	(182)	252	248
Net income (loss) per common unit (Note 14) – basic and diluted[b]	**$(2.68)**	$3.16	$3.21
Weighted average common units outstanding *(millions)* – basic and diluted	**71.3**	69.2	65.7
Common units outstanding, end of year *(millions)*	**71.3**	70.6	67.4

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 8).

[b] Net income (loss) 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 COMPREHENSIVE INCOME (LOSS)

Year ended December 31 (millions of dollars)	**2018**	2017	2016[a]
Net income (loss)	**(165)**	263	263
Other comprehensive income (loss)			
Change in fair value of cash flow hedges (Notes 12 and 20)	**(2)**	5	3
Reclassification to net income of gains and losses on cash flow hedges (Notes 12 and 20)	**5**	–	(2)
Amortization of realized loss on derivative instrument (Notes 12 and 20)	**1**	1	1
Other comprehensive income on equity investments (Note 12)	**(1)**	1	–
Comprehensive income (loss)	**(162)**	270	265
Comprehensive income attributable to non-controlling interests	**17**	11	16
Comprehensive income (loss) attributable to controlling interests	**(179)**	259	249

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 8).

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)	2018	2017	2016[a]
Cash Generated from Operations			
Net income (loss)	**(165)**	263	263
Depreciation	**97**	97	96
Impairment of long lived assets (Note 7)	**537**	–	–
Impairment of goodwill (Note 4)	**59**	–	–
Amortization of debt issue costs reported as interest expense (Note 13)	**2**	2	2
Amortization of realized loss on derivative instrument (Note 20)	**1**	1	1
Equity earnings from equity investments (Note 5)	**(173)**	(124)	(97)
Distributions received from operating activities of equity investments (Note 5)	**188**	140	153
Change in other long-term liabilities	**(2)**	–	–
Equity allowance for funds used during construction	**(1)**	(1)	–
Change in operating working capital (Note 16)	**(3)**	(2)	(1)
	540	376	417
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)	**10**	5	–
Acquisition of a 49.34 percent in Iroquois and an additional 11.81 percent in PNGTS (Note 8)	**–**	(646)	–
Acquisition of 49.9 percent interest in PNGTS (Note 8)	**–**	–	(193)
Capital expenditures	**(40)**	(29)	(29)
Other	**4**	1	1
	(35)	(761)	(230)
Financing Activities			
Distributions paid (Note 15)	**(218)**	(284)	(250)
Distributions paid to Class B units (Notes 11 and 15)	**(15)**	(22)	(12)
Distributions paid to non-controlling interests	**(14)**	(5)	(12)
Distributions paid to former parent of PNGTS	**–**	(1)	(9)
Common unit issuance, net (Note 11)	**40**	176	84
Common unit issuance subject to rescission, net (Note 11)	**–**	–	83
Long-term debt issued, net of discount (Note 9)	**219**	802	209
Long-term debt repaid (Note 9)	**(516)**	(310)	(270)
Debt issuance costs	**(1)**	(2)	(1)
	(505)	354	(178)
Increase/(decrease) in cash and cash equivalents	**–**	(31)	9
Cash and cash equivalents, beginning of year	**33**	64	55
Cash and cash equivalents, end of year	**33**	33	64
Interest payments paid	**94**	79	66
State income taxes paid	**1**	2	2
Supplemental information about non-cash investing and financing activities			
Accrued capital expenditures	**7**	9	–

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 8).

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 Common Units		Limited Partners Class B Units		General Partner	Accumulated Other Comprehensive Income (Loss)[a]	Non-Controlling Interest	PNGTS[c]	Total Equity
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 11)	1.6	81	–	–	2	–	–	–	83
Reclassification of common unit issuance subject to rescission, net[b] (Note 11)	–	(81)	–	–	(2)	–	–	–	(83)
ATM Equity Issuance, net (Note 11)	1.5	82	–	–	2	–	–	–	84
Acquisition of 49.9 percent interest in PNGTS (Note 8)	–	(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 11)	3.2	173	–	–	3	–	–	–	176
Reclassification of common units no longer subject to rescission (Note 11)	–	81	–	–	2	–	–	–	83
Acquisition of interests in PNGTS and Iroquois (Note 8)	–	(383)	–	–	(8)	–	–	(32)	(423)
Distributions	–	(268)	–	(22)	(16)	–	(3)	(1)	(310)
Partners' Equity at December 31, 2017	70.6	824	1.9	110	24	5	105	–	1,068
Net income (loss)	–	(191)	–	13	(4)	–	17	–	(165)
Other comprehensive income	–	–	–	–	–	3	–	–	3
ATM equity issuances, net (Note 11)	0.7	39	–	–	1	–	–	–	40
Distributions	–	(210)	–	(15)	(8)	–	(14)	–	(247)
Partners' Equity at December 31, 2018	**71.3**	**462**	**1.9**	**108**	**13**	**8**	**108**	**–**	**699**

[a] Gains or (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 8).

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.

At December 31, 2018, 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 and an intermediate general partnership, TC PipeLines Intermediate GP, LLC:

Pipeline	Length	Description	Ownership
GTN	1,377 miles	Extends between an interconnection near Kingsgate, British Columbia, Canada at the Canadian border to a point near Malin, Oregon at the California border and delivers natural gas to the Pacific Northwest and to California.	100 percent
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	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	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	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
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 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 MNOC, a wholly owned subsidiary of MNE. MNE is a subsidiary of Enbridge Inc.	61.71 percent
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	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

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 a two percent general partner interest in the Partnership at December 31, 2018. TransCanada also indirectly holds an additional 11,287,725 common units, for a total ownership of approximately 24 percent of our outstanding common units and 100 percent of our Class B units at December 31, 2018 (Refer to Note 11).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated financial statements and related notes have been prepared in accordance with U.S. 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, 2018 and 2017 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2018, 2017 and 2016.

(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, with the exception of 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 8). As a result of the Partnership owning 61.71 percent of PNGTS, the Partnership's 2016 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 a 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 8). Accordingly, this transaction was accounted for as a transaction between entities under common control, similar to a 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 was eliminated as a result of consolidating PNGTS for all periods presented. Refer to Note 8 for additional disclosure regarding the 2016 PNGTS Acquisition.

(b) Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates.

(c) Cash and Cash Equivalents

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

(d) Trade Accounts Receivable

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

(e) 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) Property, plant and Equipment

Property, plant 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 of our subsidiaries' assets is based on rates approved by FERC from the pipelines' last rate proceeding and 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 on the average cost of debt and equity. Capitalized carrying costs for AFUDC debt and equity are reflected as an increase in the cost of property, plant 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 property, plant 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

The Partnership's revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas which are treated as a bundled performance obligation. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed. Revenues are invoiced and paid on a monthly basis. The Partnership's pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline systems are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained, as applicable, at the time a regulatory decision becomes final.

(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

U.S. 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 operations, is includable in the U.S. 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 for impairment on an annual basis or more frequently if any indicators of impairment are evident. The Partnership can initially assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired and if the Partnership concludes that it is not more likely than not that fair value of the reporting unit is greater than its carrying value, the Partnership will then perform the quantitative goodwill impairment test. The Partnership can also elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Partnership compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

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, with the exception of 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. 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. 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.

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 any 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's assets have indeterminate lives and, accordingly, has recorded no asset retirement obligation as of December 31, 2018 and 2017.

(r) Government Regulation

At December 31, 2018, the Partnership had regulatory assets amounting to $2 million reported on the balance sheet as part of other current assets and $2 million regulatory liabilities reported on the balance sheet as part of accounts payable and accrued liabilities both representing volumetric fuel tracker assets that are settled with in-kind exchanges with customers on a continued basis (2017 – nil). Long-term regulatory liabilities are included on the balance sheet as part of other liabilities (refer to Note 10). AFUDC is capitalized and included in property, plant and equipment.

NOTE 3 ACCOUNTING PRONOUNCEMENTS

Changes in Accounting Policies effective January 1, 2018

Revenue from contracts with customers

In 2014, the Financial Accounting Standards Board (FASB) issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Partnership's "performance obligations." The total consideration to which the Partnership expects to be entitled can include fixed and variable amounts. The Partnership has variable revenue that is subject to factors outside the Partnership's influence, such as market volatility, actions of third parties and weather conditions. The Partnership considers this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided. The Partnership has elected to utilize the practical expedient of recognizing revenue as invoiced, also known as the "right to invoice" practical expedient.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and the related cash flows. Effective January 1, 2018, the new guidance was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 6 – Revenues, for further information related to the impact of adopting the new guidance and the Partnership's updated accounting policies related to revenue recognition from contracts with customers.

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 operations line items. This new guidance is effective January 1, 2019 with early adoption permitted. The Partnership has elected to early adopt this guidance and prospectively applied this guidance effective January 1, 2018. The application of this guidance did not have a material impact on its consolidated financial statements.

Goodwill Impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is 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 with early adoption is permitted. The Partnership elected to adopt this guidance effective fourth quarter of 2018 as it simplifies the goodwill impairment test. The guidance was applied prospectively and used in its 2018 annual goodwill impairment testing.

Future accounting changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required 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. 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. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of operations. The new guidance does not make extensive changes to lessor accounting.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Partnership will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Partnership will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Partnership will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The Partnership will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard. The Partnership will elect all of the new standard's available transition practical expedients.

The Partnership believes that the primary effects of adoption will relate to the recognition of new ROU assets and lease liabilities on the Partnership's balance sheet for its operating leases and new disclosures about the Partnership's leasing activities. The guidance will not impact the Partnership's income statement. The Partnership's adoption of this guidance will not have a material impact on its consolidated financial statements. The new standard also provides practical expedients for a Partnership's ongoing accounting. The Partnership will elect the short-term lease recognition exemption for all leases. This means, for those leases that qualify, the Partnership will not recognize ROU assets or lease liabilities. The Partnership will also elect the practical expedient to not separate lease and non-lease components for all leases for which the Partnership is the lessee.

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income (loss). The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Fair Value Measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for the fair value measurements as part of its disclosure framework project. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Partnership is currently evaluating the impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020, and will be applied on a retrospective basis. The Partnership is currently evaluating the timing and impact of adoption of this guidance.

NOTE 4 GOODWILL AND REGULATORY

In December 2016, FERC issued Docket No. PL17-1-000 which is an NOI Regarding the Commission's Policy for Recovery of Income Tax Costs requesting initial comments regarding how to address any "double recovery" resulting from FERC's current income tax allowance and rate of return policies that had been in effect since 2005.

Docket No. PL17-1-000 is a direct response to *United Airlines, Inc., et al. v. FERC (United)*, 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 an MLP 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.

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 including a reduction of the U.S. federal corporate income tax rate. Under the 2017 Tax Act, we continue to be a non-taxable limited partnership for U.S. federal income tax purposes, and federal 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 with respect to U.S. federal income taxes as a result of the 2017 Tax Act.

On March 15, 2018, FERC issued the following: (1) the Revised Policy Statement, (2) the NOPR and (3) the NOI. On July 18, 2018, FERC issued (1) an Order on Rehearing and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR. On November 15, 2018, FERC issued the Excess ADIT Policy Statement, addressing certain issues raised in the NOI issued on March 15, 2018. Each of the 2018 FERC Actions is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates
The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP owned pipeline is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance regarding ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as the refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on FERC Rate Changes for Interstate Natural Gas Companies
The Final Rule established a schedule by which interstate pipelines must have either (i) filed a new uncontested rate settlement or (ii) filed a one-time report, called FERC Form No. 501-G, that quantified the rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. Pipelines filing the one-time report had four options:

- Option 1: make a limited NGA Section 4 filing to reduce its rates by the reduction in its cost of service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guaranteed a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G showed the pipeline's estimated ROE as being 12 percent or less. Under the Final Rule and notwithstanding the Revised Policy Statement, a pipeline organized as an MLP is not required to eliminate its income tax allowance but, instead can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance, along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base used for rate-making purposes;
- Option 2: commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believed that using the limited Section 4 option would not result in just and reasonable rates. If the pipeline committed to file by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it did not believe the pipeline's rates must change; and
- Option 4: take no action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that had not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates
In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, was required by FERC related to the ADIT that were reserved in anticipation of being paid to the IRS, but which no longer accurately reflected the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated rates or earnings.

As noted above, FERC's Order on Rehearing provided guidance regarding ADIT for MLP pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

As noted above, on November 15, 2018, FERC issued the Excess ADIT Policy Statement addressing certain (but not all) issues raised in the NOI. The Excess ADIT Policy Statement clarified the FERC accounts in which pipelines should record amortization of excess and/or deficient ADIT for accounting and rate-making purposes.

The Excess ADIT Policy Statement also addressed how to disclose reversals of ADIT account balances in FERC's annual financial report filings. The policy statement also stated that, for those pipelines that continue to have an income tax allowance, excess/deficient ADIT associated with an asset that is sold or retired after December 31, 2017 must continue to be amortized in rates even after the sale or retirement of the asset.

Filings required by the Final Rule

Prior to the 2018 FERC Actions, the Partnership's pipeline systems did not have a requirement to file or adjust their rates earlier than 2022 as a result of their existing rate settlements. However, several of our pipeline systems accelerated such adjustments as a result of the 2018 FERC Actions as summarized in the table below.

	Form 501-G Filing Option	Impact on Maximum Rates	Moratorium and Mandatory Filing Requirements and Other Considerations
Great Lakes	Option 1; accepted by FERC	2.0% rate reduction effective February 1, 2019	No moratorium in effect; comeback provision with new rates to be effective by October 1, 2022
GTN	Settlement approved by FERC on November 30, 2018 eliminating the requirement to file Form 501-G	A refund of $10 million to its firm customers in 2018; 10.0% rate reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021; These reductions will replace the 8.3% rate reduction in 2020 agreed to as part of the last settlement in 2015	Moratorium on rate changes until December 31, 2021; comeback provision with new rates to be effective by January 1, 2022
Northern Border	Option 1; accepted by FERC	2.0% rate reduction effective February 1, 2019; proposed additional 2.0% rate reduction effective January 1, 2020	No moratorium in effect; comeback provision with new rates to be effective by July 1, 2024
Bison	Option 3	No rate change proposed	No moratorium or comeback provisions
Iroquois	Option 3; subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 9, 2019.	Expected to reduce rates by the impact of the 2017 Tax Act as shown on Form 501-G	Likely to be reaffirmed with the settlement
PNGTS	Option 3; accepted by FERC	No rate change proposed	No moratorium or comeback provisions
North Baja	Option 1; accepted by FERC	10.8% rate reduction effective December 1, 2018	No moratorium or comeback provisions; approximately 90% of North Baja's contracts are negotiated; 10.8% reduction on maximum rate contracts only
Tuscarora	Option 1; subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 29, 2019	Expected to be finalized with the settlement	Expected to be finalized with the settlement

Rate settlements

As noted in the above table, new rate settlements were entered into by GTN, Tuscarora and Iroquois to address the issues that came out of the 2018 FERC Actions. The terms of the settlements are outlined below:

GTN

On October 16, 2018, GTN filed a rate settlement with FERC to address the changes proposed by the 2018 FERC Actions within its rates via an amendment to its prior settlement in 2015. The 2018 GTN Settlement decreased GTN's existing maximum transportation rates by 10 percent effective January 1, 2019 until December 31, 2019. The existing maximum rates will decrease by an additional 6.6 percent for the period January 1, 2020 through December 31, 2021. GTN is required to have new rates in effect on January 1, 2022. Furthermore, GTN and its customers have agreed upon a moratorium on further rate changes until December 31, 2021. The 2018 GTN Settlement will also reflect an elimination of tax allowance previously recovered in rates along with ADIT for rate-making purposes. The uncontested settlement, which was approved by FERC on November 30, 2018, relieved GTN of its obligation to file a Form 501-G.

As part of the 2018 GTN Settlement, GTN has also agreed to issue a refund of approximately $10 million allocated amongst firm customers from January 1, 2018 to October 31, 2018 (2018 GTN Rate Refund). As a result of this, the Partnership established a $10 million provision for this revenue sharing as an offset against revenue in the income statement. The corresponding refund liability was paid by GTN before December 31, 2018.

Tuscarora

On December 6, 2018, Tuscarora elected to make a limited NGA Section 4 filing to reduce its maximum rates by approximately 1.7 percent and eliminate its deferred income tax balances previously used for rate setting (Option 1). On January 29, 2019, Tuscarora notified FERC that it had reached a settlement-in-principle with its customers to address the changes proposed by the 2018 FERC Actions. Moratorium provisions and other terms such as comeback provisions are still being finalized but Tuscarora agreed to continue reducing its existing maximum system rates by 1.7 percent effective February 1, 2019 as noted in its limited NGA Section filing.

Iroquois

On December 6, 2018, Iroquois submitted its FERC Form No. 501-G in response to the FERC Final Rule along with an explanation as to why rate changes were not required (Option 3). On January 9, 2019, Iroquois notified FERC that it had reached a settlement-in-principle with its customers to address the changes proposed by the 2018 FERC Actions. Iroquois has agreed to reduce its existing maximum system rates by the impact of the 2017 Tax Act changes as shown in Iroquois' Form 501-G filed with FERC.

Tuscarora Goodwill Impairment

As noted above, in the fourth quarter of 2018, Tuscarora initiated its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its maximum rates. In connection with our annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, which included estimates related to discount rates and earnings multiples. In doing so, we incorporated the expected impact of Tuscarora's regulatory approach in response to the 2018 FERC Actions, in which it elected to make a limited NGA Section 4 filing to reduce its maximum rates and eliminate its deferred income tax balances previously used for rate setting. Additionally, we have considered in our overall conclusion the outcome of the January 2019 settlement-in-principle reached by Tuscarora with its customers.

Our analysis resulted in the estimated fair value of Tuscarora not exceeding its carrying value, including goodwill. The fair value was measured using a discounted cash flow approach whereby the expected cashflows were discounted using a risk adjusted discount rate to determine fair value.

As a result, we recorded a goodwill impairment charge amounting to $59 million against Tuscarora's goodwill balance of $82 million. The impairment charge was recorded in the Impairment of goodwill line on the Consolidated statement of operations and reduced our total consolidated goodwill balance from $130 million to $71 million. There is a risk that adverse changes in our key assumptions could result in an additional future impairment on Tuscarora's remaining goodwill of $23 million.

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.

	Ownership Interest at December 31,	Equity Earnings[b]			Equity Investments	
		Year ended December 31			December 31	
(millions of dollars)	**2018**	**2018**	2017	2016[c]	**2018**	2017
Northern Border[a]	50.00%	**68**	67	69	**497**	512
Great Lakes	46.45%	**59**	31	28	**489**	479
Iroquois	49.34%	**46**	26	–	**210**	222
		173	124	97	**1,196**	1,213

(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.

(c) Recast to eliminate equity earnings from PNGTS and consolidate PNGTS (Refer to Notes 2 and 8).

Distributions from Equity Investments

Distributions received from equity investments for the year ended December 31, 2018 were $198 million (2017 – $145 million; 2016 – $153 million) of which $10 million (2017 – $5 million and 2016 – 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 a subsidiary of ONEOK, Inc. TC PipeLines Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Northern Border. The Partnership effectively holds a 100% percent 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, 2018, 2017 and 2016. At December 31, 2018 the Partnership had a $115 million (December 31, 2017 – $115 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.

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

December 31 (millions of dollars)	**2018**	2017
Assets		
Cash and cash equivalents	**10**	14
Other current assets	**36**	36
Property, plant and equipment, net	**1,037**	1,063
Other assets	**13**	14
	1,096	1,127
Liabilities and Partners' Equity		
Current liabilities	**34**	38
Deferred credits and other	**35**	31
Long-term debt, net[(a)]	**264**	264
Partners' equity		
Partners' capital	**764**	795
Accumulated other comprehensive loss	**(1)**	(1)
	1,096	1,127

Year ended December 31 (millions of dollars)	**2018**	2017	2016
Transmission revenues	**289**	291	292
Operating expenses	**(78)**	(78)	(72)
Depreciation	**(60)**	(59)	(59)
Financial charges and other	**(15)**	(18)	(21)
Net income	**136**	136	140

(a) No current maturities as of December 31, 2018 or 2017.

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 effectively holds a 100 percent partnership interest in TC GL Intermediate Limited Partnership.

The Partnership recorded no undistributed earnings from Great Lakes for the years ended December 31, 2018, 2017, and 2016.

The Partnership made equity contributions to Great Lakes of $4 million and $5 million in the first and fourth quarter of 2018, 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.

At December 31, 2018, the equity method goodwill balance related to Great Lakes amounted to $260 million (December 31, 2017 – $260 million). The equity method goodwill relates to the Partnership's February 2007 acquisition of a 46.45 percent general partner interest in Great Lakes and is the difference between the carrying value of our investment in Great Lakes and the underlying equity in Great Lakes' net assets.

During the fourth quarter of 2018, Great Lakes finalized its regulatory approach in response to the 2018 FERC Actions and elected to make a limited NGA section 4 filing with FERC to reduce its maximum rates and eliminate its tax allowance and deferred income tax balances previously used for rate setting. As a result of this action, and because the estimated fair value of our investment in Great Lakes exceeded its carrying value by less than 10 percent in its 2017 valuation, we performed a quantitative test to determine if there was other than temporary decline in Great Lakes' fair value. At December 31, 2018, the estimation of the fair value of our remaining equity investment in Great Lakes was completed and we concluded the fair value of our investment exceeded its current carrying value by more than 10 percent.

The assumptions we used in the analysis related to the estimated fair value of our equity investment in Great Lakes included expected results from its limited NGA Section 4 filing, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment, which includes estimates related to discount rates and earnings multiples. Although our analysis indicated that 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 impairment of the carrying value of our investment in Great Lakes.

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

December 31 (millions of dollars)	**2018**	2017
Assets		
Current assets	**75**	107
Property, plant and equipment, net	**689**	701
	764	808
Liabilities and Partners' Equity		
Current liabilities	**26**	75
Long-term debt, net[(a)]	**240**	259
Other long-term liabilities	**4**	1
Partners' equity	**494**	473
	764	808

Year ended December 31 (millions of dollars)	**2018**	2017	2016
Transmission revenues	**246**	181	179
Operating expenses	**(68)**	(66)	(69)
Depreciation	**(32)**	(29)	(28)
Financial charges and other	**(18)**	(20)	(21)
Net income	**128**	66	61

(a) Includes current maturities of $21 million as of December 31, 2018 (December 31, 2017 – $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, 2018, The Partnership received distributions from Iroquois amounting to $56 million (2017 – $27 million) which includes the Partnership's 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately $10 million (2017 – $5 million) (Refer to Note 8). 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 year ended December 31, 2018 and for the period from June 1, 2017, acquisition date, through December 31, 2017. At December 31, 2018 and 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, 2018 is as follows:

December 31 (millions of dollars)	**2018**	2017
ASSETS		
Cash and cash equivalents	**80**	86
Other current assets	**32**	36
Property, plant and equipment, net	**581**	591
Other assets	**8**	8
	701	721
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	**19**	17
Net long-term debt, net[a]	**325**	329
Other non-current liabilities	**14**	9
Partners' equity	**343**	366
	701	721

(millions of dollars)	**Year ended December 31, 2018**	Period of 7 months ended December 31, 2017
Transmission revenues	**194**	110
Operating expenses	**(57)**	(32)
Depreciation	**(29)**	(17)
Financial charges and other	**(14)**	(9)
Net income	**94**	52

[a] Includes current maturities of $146 million as of December 31, 2018 (December 31, 2017 – $4 million).

NOTE 6 REVENUES

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for all periods in 2018 reflect the application of the new guidance, while the reported results for all periods in 2017 and 2016 were prepared under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP".

Disaggregation of Revenues

For the year ended December 31, 2018, virtually all of the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2 – Significant Accounting Policies.

During the fourth quarter of 2018, Bison received an unsolicited offer from Tenaska regarding the termination of its contract. Also during 2018, through a Permanent Capacity Release Agreement, Tenaska assumed Anadarko's ship-or-pay contract obligation on Bison, which was the largest contract on Bison. Bison and Tenaska mutually agreed to terms which included a non-refundable payment to Bison of $95.4 million in December 2018 in exchange for the termination of all its contract obligations with Bison. Following the amendment of its tariff to enable this transaction, another customer executed a similar agreement to terminate its contract on Bison in exchange for a non-refundable payment to Bison of approximately $2.0 million in December 2018. At the termination of the contracts, Bison was released from performing any future services with the two customers and as such, the amounts received were recorded in revenue in 2018. Accordingly, the Partnership considers the $97 million received as a result of the contract terminations as revenue from capacity and transportation contracts with customers and therefore no further disaggregation of revenue is needed (See also related discussion under Note 7 – Plant Property and Equipment).

As noted under Note 2 – Significant Accounting Policies, a portion of our revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. We use our best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue we recognized. Accordingly, as part of the 2018 GTN Settlement, we have issued the 2018 GTN Rate Refund and recognized a $10 million offset against revenue in the income statement (See also Note 4 for more information).

Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Partnership adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Partnership is not required to analyze completed contracts at the date of adoption. The adoption of the new guidance did not have a material impact on the Partnership's previously reported consolidated financial statements at December 31, 2017.

Pro-forma Financial Statements under Legacy U.S. GAAP

At December 31, 2018, had legacy U.S. GAAP been applied, there would be no change in the Partnership's reported balance sheet and income statement line items.

Contract Balances

All of the Partnership's contract balances pertain to receivable from contracts with customers amounting to $44 million at December 31, 2018 and $40 million at January 1, 2018 and are both recorded as Trade accounts receivable and reported as Accounts receivable and other in the Partnership's Consolidated Balance Sheet (Refer to Note 21). Additionally, our accounts receivable represents the Partnership's unconditional right to recognize revenue for services completed which includes billed and unbilled accounts.

Future revenue from remaining performance obligations

When the right to invoice practical expedient is applied, the guidance does not require disclosure of information related to future revenue from remaining performance obligations therefore no additional disclosure is required.

Additionally, in the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized on a monthly basis once the Partnership's performance obligation to provide capacity has been satisfied.

NOTE 7 PROPERTY, PLANT AND EQUIPMENT

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

	2018			2017		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Pipeline	**1,901**	**(876)**	**1,025**	2,577	(962)	1,615
Compression	**550**	**(182)**	**368**	533	(165)	368
Metering and other	**176**	**(52)**	**124**	182	(54)	128
Construction in progress	**12**	**–**	**12**	12	–	12
	2,639	**(1,110)**	**1,529**	3,304	(1,181)	2,123

Impairment of Bison's long-lived assets

With the advanced payments to Bison and related cancellation of certain customer transportation contracts as noted under Note 6-Revenues, Bison's future revenue will be reduced by approximately $47 million per year in both 2019 and 2020. Additionally, natural gas is currently not flowing on Bison as a result of the relative cost advantage of WCSB – and Bakken – sourced gas versus Rockies production. Since its inception in January 2011, Bison has not experienced a decrease in its revenue as its original ten-year contracts included ship-or-pay terms that resulted in payment to Bison regardless of gas flows. The customer contract cancellations coupled with the persistence of unfavorable market conditions which have inhibited system flows have prompted management to re-evaluate the carrying value of Bison's long-lived assets.

Although the Partnership continues to evaluate alternatives for recontracting or redevelopment of Bison, management is currently unable to quantify the future cash flows of a viable, operating plan beyond the remaining customer contracts' expiry in January 2021, and accordingly the Partnership evaluated for impairment the carrying value of its property, plant and equipment on Bison at December 31, 2018. The Partnership will continue to maintain Bison to stand ready for redevelopment and has concluded that the remaining obligations of Bison, primarily in the form of ad valorem tax obligations and operating and maintenance costs, exceed the net cash inflows that management currently considers probable and estimable.

Based on these factors, during the fourth quarter of 2018, the Partnership recognized an impairment charge of $537 million relating to the remaining carrying value of Bison's property, plant and equipment after determining that it was no longer recoverable. The impairment charge was recorded under Impairment of long-lived assets line on the Consolidated statement of operations.

NOTE 8 ACQUISITIONS

2017 Acquisition

On June 1, 2017, the Partnership acquired from subsidiaries of TransCanada a 49.34 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, which expired on January 3, 2019. 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 9) 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 of this acquisition transaction. The Partnership is expected to receive the $28.4 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 21, 2019, the Partnership has received approximately $18.1 million of the expected $28.4 million, of which $2.6 million was received as of February 21, 2019 (Refer to Note 25), 10.3 million in 2018 and 5.2 million in 2017.

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 2016 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.

NOTE 9 DEBT AND CREDIT FACILITIES

(millions of dollars)	2018	Weighted Average Interest Rate for the Year Ended December 31, 2018	2017	Weighted Average Interest Rate for the Year Ended December 31, 2017
TC PipeLines, LP				
Senior Credit Facility due 2021	**40**	3.14%	185	2.41%
2013 Term Loan Facility due 2022	**500**	3.23%	500	2.33%
2015 Term Loan Facility due 2020	**–**	–	170	2.22%
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)]	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	**35**	2.93%	55	2.02%
PNGTS				
Revolving Credit Facility due 2023	**19**	3.55%	–	–
5.90% Senior Secured Notes due 2018	**–**	–	30	5.90%[(a)]
Tuscarora				
Unsecured Term Loan due 2020	**24**	3.10%	25	2.27%
North Baja				
Unsecured Term Loan due 2021	**50**	3.54%	–	–
	2,118		2,415	
Less: unamortized debt issuance costs and debt discount	**10**		12	
Less: current portion	**36**		51[(b)]	
	2,072		2,352	

(a) Fixed interest rate.

(b) 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 $40 million was outstanding at December 31, 2018 (December 31, 2017 – $185 million), leaving $460 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 3.77 percent at December 31, 2018 (December 31, 2017 – 2.62 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 a dropdown transaction with TransCanada in 2013, 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 U.S. 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, 2018, 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 3.26 percent (2017 – 2.31 percent). Prior to hedging activities, the LIBOR-based interest rate was 3.60 percent at December 31, 2018 (December 31, 2017 – 2.62 percent).

In December 2018, the Partnership fully repaid its 2015 Term Loan Facility using proceeds primarily from Bison's early contract termination with two of its customers (Refer to Notes 6 and 17) and available cash.

The Senior Credit Facility and the 2013 Term Loan 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 3.12 to 1.00 as of December 31, 2018.

The Senior Credit Facility and the 2013 Term Loan Facility 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 2013 Term Loan Facility may become immediately due and payable.

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 8). The indenture for the notes contains customary investment grade covenants.

PNGTS

On April 5, 2018, PNGTS entered into a revolving credit agreement under which PNGTS has the ability to borrow up to $125 million with a variable interest rate based on LIBOR. The credit agreement matures on April 5, 2023 and requires PNGTS to maintain a leverage ratio not greater than 5.00 to 1.00. The leverage ratio was 0.35 to 1.00 as of December 31, 2018. The facility is utilized primarily to fund the costs of the PXP expansion project and to finance PNGTS' other funding needs. As of December 31, 2018, $19 million was drawn on the Revolving Credit Facility and the LIBOR-based interest rate was 3.60 percent.

GTN

On June 1, 2015, GTN entered into a $75 million unsecured variable rate term loan facility (GTN 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 GTN Unsecured Term Loan Facility was 3.30 percent at December 31, 2018 (December 31, 2017 – 2.31 percent). GTN's Unsecured Senior Notes, along with the GTN Unsecured Term 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, 2018 is 42.8 percent.

Tuscarora

On August 21, 2017, Tuscarora refinanced all of its outstanding debt by amending its existing Unsecured Term Loan Facility (Tuscarora 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. The Tuscarora 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, 2018, the ratio was 10.29 to 1.00.

The LIBOR-based interest rate on the Tuscarora Unsecured Term Loan Facility was 3.47 percent at December 31, 2018 (December 31, 2017 – 2.49 percent).

North Baja

On December 19, 2018, North Baja entered into a $50 million unsecured variable rate term loan facility, which matures on December 19, 2021. The net proceeds were used for general partnership purposes. The variable interest rate is based on LIBOR plus an applicable margin. The LIBOR-based interest rate on this term loan facility was 3.54 percent at December 31, 2018. North Baja's Term Loan Facility contains a covenant that limits total debt to no greater than 70 percent of North Baja's total capitalization. North Baja's total debt to total capitalization ratio at December 31, 2018 is 37.7 percent.

Partnership (TC PipeLines, LP and its subsidiaries)

At December 31, 2018, 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)	
2019	36
2020	123
2021	440
2022	500
2023	19
Thereafter	1,000
	2,118

NOTE 10 OTHER LIABILITIES

December 31 (millions of dollars)	2018	2017
Regulatory liabilities	**27**	26
Other liabilities	**2**	3
	29	29

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 on 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 11 PARTNERS' EQUITY

At December 31, 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 a 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 2018, the Partnership issued 0.7 million common units under the ATM Program generating net proceeds of approximately $39 million, plus an additional $1 million from the General Partner to maintain its effective two percent interest. The commissions to our sales agents were nil. The net proceeds were used to repay a portion of the borrowings under the Senior Credit Facility and for general partnership purposes.

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.

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.

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, the amount associated with these rights was reclassified back to partners' equity. At December 31, 2018, there were no outstanding common units subject to rescission on the Partnership's consolidated balance sheet.

Issuance of Class B units

The Class B Units issued on April 1, 2015 to finance a portion of the Partnership's acquisition of the remaining 30 percent interest from TransCanada represent a limited partner interest in us and entitle TransCanada to an annual 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. 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.

Additionally, the Class B Distribution was reduced by 35 percent, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018. The Class B Reduction was implemented during the first quarter of 2018 following the Partnership's common unit distribution reduction of 35 percent from its fourth quarter 2017 distribution level per common unit. The Class B Reduction will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit.

The Class B units' equity account is increased by the "Class B Distribution", less the "Class B Reduction", if any until such amount is declared for distribution and paid every first quarter of the subsequent year. For the years ended December 31, 2018, 2017 and 2016, the Class B units' equity account was increased by $13 million, $15 million and $22 million, respectively. (Refer to Notes 14 and 15).

NOTE 12 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**	Equity Investments	Total
Balance at December 31, 2015[(a)]	**(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 20)*[(a)]	**1**	–	1
Net other comprehensive income[(a)]	**2**	–	2
Balance at December 31, 2016[(a)]	**(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 20)*	**1**		1
Other comprehensive income – effects of Iroquois' retirement benefit plans	**–**	1	1
Net other comprehensive income	**6**	1	7
Balance at December 31, 2017	4	1	5
Change in fair value of cash flow hedges	**(2)**	–	(2)
Amounts reclassified from AOCI	**5**	–	5
PNGTS' amortization of realized loss on derivative instrument *(Note 20)*	**1**	–	1
Other comprehensive income (loss) – effects of Iroquois' retirement benefit plans	**–**	(1)	(1)
Net other comprehensive income (loss)	**4**	(1)	3
Balance as of December 31, 2018	**8**	–	8

(a) Recast to consolidate PNGTS (Refer to in Notes 2 and 8). Additionally, AOCI as presented here is net of non-controlling interest on PNGTS.

NOTE 13 FINANCIAL CHARGES AND OTHER

Year ended December 31 (millions of dollars)	**2018**	2017	2016[a]
Interest expense[b]	**95**	83	69
Net realized loss related to the interest rate swaps	**(2)**	–	3
PNGTS' amortization of realized loss on derivative instrument *(Note 20)*	**1**	1	1
Other	**(2)**	(2)	(2)
	92	82	71

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 8).

[b] Interest expense includes amortization of debt issuance costs and discount costs.

NOTE 14 NET INCOME (LOSS) 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 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 15).

The amount allocable to the Class B units is based upon 30 percent of GTN's distributable cash flow during the year ended December 31, 2018 after certain annual thresholds and adjustments (Refer to Note 11).

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

(millions of dollars, except per common unit amounts)	**2018**	2017	2016
Net income (loss) attributable to controlling interests[a]	**(182)**	252	248
Net income attributable to PNGTS' former parent[a][b]	**–**	(2)	(4)
Net income (loss) allocable to General Partner and Limited Partners	**(182)**	250	244
Incentive distributions attributable to the General Partner[c]	**–**	(12)	(7)
Net income attributable to the Class B units[d]	**(13)**	(15)	(22)
Net income (loss) allocable to the General Partner and common units	**(195)**	223	215
Net (income) loss allocable to the General Partner's two percent interest	**4**	(4)	(4)
Net income (loss) attributable to common units	**(191)**	219	211
Weighted average common units outstanding *(millions)* – basic and diluted	**71.3**	69.2	65.7[e]
Net income (loss) per common unit – basic and diluted[f]	**$(2.68)**	$3.16	$3.21

[a] Recast to consolidate PNGTS in 2016 (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 11, 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 and Class B Reduction. 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 distribution in an amount equal to 30 percent of GTN's total distributable cash flows during the year ended December 31, 2018 less the threshold level of $20 million (2017 and 2016 – less $20 million) and less the Class B Reduction. The Class B Reduction did not apply during 2017 and 2016. During the year ended December 31, 2018, 30 percent of GTN's total distributable cash flow was $40 million. After applying the $20 million annual threshold and the Class B Reduction of

$7 million, $13 million of net income attributable to controlling interests was allocated to the Class B units at December 31, 2018 (2017 – $15 million; 2016 – $22 million).

(e) Includes the common units subject to rescission. These units are treated as outstanding for financial reporting purposes (Refer to Note 11).

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

NOTE 15 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 after providing for Class B distributions based on the specified target distribution levels. The percentage interests set forth below for our General Partner include its IDRs and effective two percent general partner interest through December 31, 2018 and two percent general partner interest thereafter and assume our General Partner has contributed any additional capital necessary to maintain its two percent general partner interest. The percentage interest distributions to the General Partner illustrated below that are in excess of its two percent general partner interest represent 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[b]	2%	IDRs[a]	Total Cash Distribution
1/21/2016	2/12/2016	$0.89	$57	$12	$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	$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	2/13/2018	$1.00	$71	$15	$2	$3	$91
5/1/2018	5/15/2018	$0.65	$46	$ –	$1	$–	$47
7/26/2018	8/15/2018	$0.65	$46	$ –	$1	$–	$47
10/23/2018	11/14/2018	$0.65	$46	$ –	$1	$–	$47
1/22/2019[c]	2/11/2019[c]	$0.65	$46	$13	$1	$–	$60

(a) The distributions paid during the year ended December 31, 2018 included incentive distributions to the General Partner of $3 million (2017 – $10 million, 2016 – $6 million).

(b) 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 and adjustments (refer to Note 11)

(c) On February 11, 2019, we paid a cash distribution of $0.65 per unit on our outstanding common units to unitholders of record at the close of business on February 1, 2019 (refer to Note 25).

NOTE 16 CHANGE IN OPERATING WORKING CAPITAL

Year Ended December 31 (millions of dollars)	**2018**	2017	2016[b]
Change in accounts receivable and other	**(6)**	4	(4)
Change in other current assets	**(1)**	2	(4)
Change in accounts payable and accrued liabilities[a]	**3**	(7)	5
Change in accounts payable to affiliates	**1**	(3)	–
Change in accrued interest	**–**	2	2
Change in operating working capital	**(3)**	(2)	(1)

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

(b) Recast to consolidate PNGTS (Refer to Notes 2 and 8).

NOTE 17 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 revenues for the years ended December 31, 2018, 2017 and 2016:

Year Ended December 31 (millions of dollars)	**2018**	2017	2016
Anadarko/Tenaska customer group[d]	**144[d]**	48	48
Pacific Gas[c]	**32[a][b]**	33[a][b]	36

At December 31, 2018 and 2017, Anadarko owed the Partnership approximately $4 million, which is approximately 10 percent of our consolidated trade accounts receivable (Refer to Note 2).

(a) Less than 10 percent of trade accounts receivable

(b) Less than 10 percent of consolidated revenue

(c) On January 29, 2019, GTN's largest customer, Pacific Gas, filed for Chapter 11 bankruptcy protection. The Partnership's accounts receivable from Pacific Gas at December 31, 2018 has been collected and for the year ended December 31, 2018, Pacific Gas accounted for approximately 6 percent of Partnership's consolidated revenue.

(d) As noted under Note 6, Tenaska assumed Anadarko's ship-or-pay contract obligation on Bison. After assuming the transportation obligation, Bison accepted an offer from Tenaska to buy out its contract. For the year ended December 31, 2018, the amount reported here are both revenues from Anadarko and Tenaska since the revenue earned by the Partnership from these customers are essentially coming from the same contract.

NOTE 18 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, 2018 (2017 – $4 million, 2016 – $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, 2018, 2017 and 2016 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at December 31, 2018 and 2017 are summarized in the following tables:

Year ended December 31 (millions of dollars)	**2018**	2017	2016
Capital and operating costs charged by TransCanada's subsidiaries to:			
Great Lakes[(a)]	**44**	36	30
Northern Border[(a)]	**36**	43	32
PNGTS[(a)(b)]	**9**	9	8
GTN	**34**	34	27
Bison	**6**	6	2
North Baja	**4**	4	4
Tuscarora	**4**	4	5
Impact on the Partnership's net income attributable to controlling interests:			
Great Lakes	**19**	15	13
Northern Border	**16**	16	12
PNGTS[(b)]	**5**	5	5
GTN	**28**	29	24
Bison	**6**	6	3
North Baja	**4**	4	4
Tuscarora	**4**	4	4

December 31 (millions of dollars)	**2018**	2017
Amount payable to TransCanada's subsidiaries for costs charged in the year by:		
Great Lakes[(a)]	**3**	3
Northern Border[(a)]	**3**	4
PNGTS[(a)]	**1**	1
GTN	**4**	3
Bison	**1**	1
North Baja	**–**	–
Tuscarora	**1**	–

(a) Represents 100 percent of the costs.

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

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 rates. For the year ended December 31, 2018, Great Lakes earned 73 percent of its transportation revenues from TransCanada and its affiliates (2017 – 57 percent; 2016 – 68 percent). Additionally, included in Great Lakes' other revenues were cost recovery charges to its affiliates for use of office space in the building it owns and is less than one percent of its total revenues in 2018 (2017 – 1 percent; 2016 – 1 percent).

At December 31, 2018, $18 million was included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2017 – $20 million).

During 2017, Great Lakes operated under a FERC approved 2013 rate settlement that included a revenue sharing mechanism that required Great Lakes to share with its customers certain percentages of any qualifying revenues earned above certain ROEs. During the second quarter of 2018, the refund was settled with its customers and a significant portion of the refund was with its affiliates. Under the terms of the 2017 Great Lakes Settlement, beginning in 2018, the revenue sharing was eliminated.

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, 2018 and 2017, Great Lakes had outstanding receivables from this arrangement amounting to $36 million and $64 million, respectively.

Great Lakes has a long-term transportation agreement with TransCanada's Canadian Mainline that commenced on November 1, 2017 for a ten-year period and allows TransCanada to transport up to 0.711 billion cubic feet of natural gas per day on the Great Lakes system. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from

TransCanada's long-term fixed price service on its Canadian Mainline that was launched in 2017. For the year ended December 31, 2018 and 2017, the total revenue earned by Great Lakes on this contract was $76 million and $13 million, respectively.

During the second quarter of 2018, Great Lakes reached an agreement on the terms of new long-term transportation capacity contracts with its affiliate, ANR Pipeline Company. The contracts are for a term of 15 years from November 2021 to October 31, 2036 with a total contract value of approximately $1.3 billion. The contracts contain reduction options (i) at any time on or before April 1, 2019 for any reason and (ii) any time before April 2021, if TransCanada is not able to secure the required regulatory approval related to anticipated expansion projects.

PNGTS
For the years ended December 31, 2018, 2017 and 2016, PNGTS provided transportation services to a related party. Revenues from TransCanada Energy Ltd., a subsidiary of TransCanada, for 2018, 2017 and 2016 were approximately $1 million, $1 million and $2 million, respectively. At December 31, 2018, PNGTS had nil outstanding receivables from TransCanada Energy Ltd. in the consolidated balance sheets (December 31, 2017 – nil).

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, 2018, the total costs incurred by these affiliates was approximately $47 million (December 31, 2017 – $3 million).

NOTE 19 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected unaudited financial data for the four quarters in 2018 and 2017:

Quarter ended (millions of dollars except per common unit amounts)	Mar 31	Jun 30	Sept 30	Dec 31
2018				
Transmission revenues	**115**	**111**	**103**[(b)]	**220**[(c)]
Equity earnings	**59**	**36**	**34**	**44**
Net income (loss)	**102**	**75**	**65**	**(406)**
Net income (loss) attributable to controlling interests	**96**	**73**	**62**	**(413)**
Net income (loss) per common unit	**$1.32**	**$1.00**	**$0.79**	**$(5.80)**
Cash distributions paid to common units[(a)]	**76**	**47**	**47**	**47**
Cash distribution paid to Class B units	**15**	**–**	**–**	**–**
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 distributions paid to common units[(a)]	68	68	74	74
Cash distribution paid to Class B units	22	–	–	–

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

(b) Net of a $9 million provision for revenue sharing recognized as part of the 2018 GTN Settlement, in which GTN agreed to issue a refund of $10 million allocated amongst its firm customers from January 1, 2018 to October 1, 2018 (Refer to Note 4).

(c) Net of a $1 million provision for revenue sharing recognized as part of the 2018 GTN Settlement, in which GTN agreed to issue a refund of $10 million allocated amongst its firm customers from January 1, 2018 to October 1, 2018 (Refer to Note 4). This amount also includes the $97 million proceeds received by Bison from the termination of certain customer contracts (Refer to Note 6).

NOTE 20 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 are classified as Level 1 in fair value hierarchy. Accordingly, the carrying values 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 as a Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified as a 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, 2018 and December 31, 2017 was $2,101 million and $2,475 million, respectively.

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

The Partnership's 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. From January 1 to June 30, 2018, the Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps at a weighted average fixed interest rate of 2.31 percent. Beginning July 1, 2018 and until its October 2, 2022 maturity, the 2013 Term Loan Facility was hedged using forward starting interest rate swaps at an average rate of 3.26 percent.

At December 31, 2018, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $8 million (on both gross and net basis). 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). The change in fair value of interest rate derivative instruments recognized in other comprehensive income was a loss of $2 million for the year ended December 31, 2018 (2017 – gain of $5 million and 2016 – gain of $3 million). During the year ended December 31, 2018, the amount reclassified from other comprehensive income to net income was a gain of $5 million (2017 – nil and 2016 – loss of $2 million). In 2018, the net realized gain related to the interest rate swaps was $2 million, and was included in financial charges and other (2017 – nil, 2016 – gain of $3 million). Refer to Note 13 – Financial Charges and Other.

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 no effect on the consolidated balance sheet as of December 31, 2018 and 2017.

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its 5.90% 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. At December 31, 2018, and as a result of the repayment of the 5.90% Senior Secured Notes, the remaining balance of the $20.9 million realized loss in AOCI included in other comprehensive income at the termination date was fully amortized against earnings. For the years ended December 31, 2018, 2017 and 2016, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $1 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, 2018, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At December 31, 2018, we had a credit risk concentration on one of our customers and the amount owed is approximately 10 percent of our trade accounts receivable and consolidated revenues (refer also to Note 17 for more details).

(c) Other

The estimated fair value measurements on Tuscarora's goodwill, Bison's long-lived assets and our equity investment in Great Lakes, are classified as Level 3. In the determination of fair value utilized in the recoverability assessments for the respective assets, 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 Notes 4 (Tuscarora), 5 (Great Lakes) and 7 (Bison).

NOTE 21 ACCOUNTS RECEIVABLE AND OTHER

December 31 (millions of dollars)	**2018**	2017
Trade accounts receivable, net of allowance of nil	**44**	40
Imbalance receivable from affiliates	**2**	1
Other	**2**	1
	48	42

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. – In 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar Steel 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. Following Great Lakes' several unsuccessful attempts at recovering the payments through the U.S. federal court system, Essar Minnesota subsequently filed for bankruptcy in July 2016 and a performance bond was released into the bankruptcy court proceedings. In 2017, after Great Lakes came to an agreement with creditors on an allowed claim, the bankruptcy court approved Great Lakes' claim in the amount of $31.5 million.

The Foreign Essar Affiliates have not filed for bankruptcy and the case against the Foreign Essar Affiliates in Minnesota state court remains pending. At December 31, 2018, Great Lakes' is unable to estimate the timing or the extent to which its claims in bankruptcy and state court will be recoverable, therefore, it did not recognize any gain contingency on its outstanding claim against Essar and the Essar Foreign Affiliates. Additionally, Great Lakes has concluded that the future recovery on this claim is remote.

Additionally, at December 31, 2018, 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.

NOTE 23 VARIABLE INTEREST ENTITIES (VIEs)

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 intermediate partnerships and mainly 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 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, Iroquois, and effective December 31, 2018, North Baja 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, 2018[a]**	December 31, 2017[b]
ASSETS (LIABILITIES)		
Cash and cash equivalents	**16**	19
Accounts receivable and other	**39**	30
Inventories	**8**	6
Other current assets	**6**	5
Equity investments	**1,196**	1,213
Property, plant and equipment	**1,240**	1,133
Other assets	**1**	1
Accounts payable and accrued liabilities	**(33)**	(24)
Accounts payable to affiliates, net	**(40)**	(42)
Distributions payable	**–**	(1)
Accrued interest	**(2)**	(2)
Current portion of long-term debt	**(36)**	(51)
Long-term debt	**(341)**	(308)
Other liabilities	**(27)**	(26)
Deferred state income tax	**(9)**	(10)

[a] Bison, an asset held through our consolidated VIEs, is excluded at December 31, 2018 as the assets of this entity can be used for purposes other than the settlement of the VIE's obligations.

[b] North Baja, which is also asset held through our consolidated VIEs, and Bison, are excluded at December 31, 2017 as the assets of these entities can be used for purposes other than the settlement of the VIE's obligations.

NOTE 24 INCOME TAXES

The Partnership's income taxes relate to business profits tax (BPT) levied at the partnership (PNGTS) level by the state of New Hampshire (NH). 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, 2018, 2017 and 2016 relate primarily to utility plant. The NH BPT effective tax rate was 3.5 percent for the year ended December 31, 2018, and 3.8 percent for the periods ended December 31, 2017 and 2016, 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)	**2018**	2017	2016[a]
State income taxes			
Current	**2**	1	1
Deferred	**(1)**	–	–
	1	1	1

[a] Recast to consolidate PNGTS (Refer to Notes 2 and 8).

NOTE 25 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through February 21, 2019, 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 22, 2019, the board of directors of our General Partner declared the Partnership's fourth quarter 2018 cash distribution in the amount of $0.65 per common unit and was paid on February 11, 2019 to unitholders of record as of February 1, 2019. The declared distribution totaled $47 million and is payable in the following manner: $46 million to common unitholders (including $4 million to the General Partner as a holder of 5,797,106 common units and $7 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $1 million to the General Partner for its two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the fourth quarter 2018.

On January 22, 2019, the board of directors of our General Partner declared its annual distribution to Class B units in the amount of $13 million which was paid on February 11, 2018. The Class B distribution represents an amount equal to 30 percent of GTN's distributable cash flow during the year ended December 31, 2018 less $20 million and the Class B Reduction.

Northern Border

Northern Border declared its December 2018 distribution of $18 million on January 7, 2019, of which the Partnership received its 50 percent share or $9 million on January 31, 2019.

Northern Border declared its January 2019 distribution of $20 million on February 14, 2019, of which the Partnership will receive its 50 percent share or $10 million on February 28, 2019.

Great Lakes

Great Lakes declared its fourth quarter 2018 distribution of $36 million on January 15, 2019, of which the Partnership received its 46.45 percent share or $17 million on February 1, 2019.

Iroquois

Iroquois declared its fourth quarter 2018 distribution of $28 million on January 22, 2019, of which the Partnership received its 49.34 percent share or $14 million on February 1, 2019. The $14 million includes our proportionate share of Iroquois' unrestricted cash amounting to $2.6 million (refer to Note 8).

PNGTS

PNGTS declared its fourth quarter 2018 distribution of $19 million on January 9, 2019, of which $7 million was paid to its non-controlling interest owner on January 31, 2018.

NORTHERN BORDER PIPELINE COMPANY
INDEPENDENT AUDITORS' REPORT

The Management Committee
Northern Border Pipeline Company:

We have audited the accompanying financial statements of Northern Border Pipeline Company (the Partnership), which comprise the balance sheets as of December 31, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 15, 2019

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

December 31, 2018 and 2017 (In thousands)	**2018**	2017
Assets		
Current assets:		
Cash and cash equivalents	**$ 9,599**	14,010
Accounts receivable	**25,641**	24,738
Related party receivables	**3,271**	3,049
Materials and supplies	**5,612**	5,216
Prepaid expenses and other	**2,132**	3,761
Total current assets	**46,255**	50,774
Property, plant and equipment:		
In-service natural gas transmission plant	**2,638,014**	2,605,625
Construction work in progress	**2,866**	5,692
Total property, plant and equipment	**2,640,880**	2,611,317
Less: Accumulated provision for depreciation and amortization	**1,604,566**	1,548,635
Property, plant and equipment, net	**1,036,314**	1,062,682
Other assets:		
Regulatory assets	**13,215**	13,994
Other	**–**	7
Total other assets	**13,215**	14,001
Total assets	**$1,095,784**	1,127,457
Liabilities and Partners' Equity		
Current liabilities:		
Accounts payable	**$ 6,028**	9,737
Related party payables	**3,680**	4,154
Accrued taxes other than income	**19,306**	19,609
Accrued interest	**4,731**	4,691
Other	**–**	243
Total current liabilities	**33,745**	38,434
Long-term debt, net	**264,455**	264,056
Deferred credits and other liabilities		
Regulatory liability	**29,598**	27,031
Other	**4,740**	4,336
Total deferred credits and other liabilities	**34,338**	31,367
Total liabilities	**332,538**	333,857
Partners' equity:		
Partners' capital	**764,209**	794,869
Accumulated other comprehensive loss	**(963)**	(1,269)
Total partners' equity	**763,246**	793,600
Total liabilities and partners' equity	**$1,095,784**	1,127,457

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

Years ended December 31, 2018, 2017, and 2016 (In thousands)	**2018**	2017	2016
Operating revenue	**$289,418**	291,396	291,642
Operating expenses:			
Operations and maintenance	**54,576**	54,374	47,652
Depreciation and amortization	**60,492**	59,426	58,813
Taxes other than income	**23,892**	23,480	24,200
Operating expenses	**138,960**	137,280	130,665
Operating income	**150,458**	154,116	160,977
Interest expense:			
Interest expense	**19,943**	22,257	25,433
Interest expense capitalized	**(101)**	(176)	(100)
Interest expense, net	**19,842**	22,081	25,333
Other income (expense):			
Allowance for equity funds used during construction	**623**	573	297
Other income	**4,505**	3,936	4,151
Other expense	**(37)**	(238)	(113)
Other income, net	**5,091**	4,271	4,335
Net income to partners	**$135,707**	136,306	139,979

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2018, 2017, and 2016 (In thousands)	**2018**	2017	2016
Net income to partners	**$135,707**	136,306	139,979
Other comprehensive income:			
Changes associated with hedging transactions	**306**	285	264
Total comprehensive income	**$136,013**	136,591	140,243

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

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

Years ended December 31, 2018, 2017, and 2016 (In thousands)	**2018**	2017	2016
Cash flows from operating activities:			
Net income to partners	**$ 135,707**	136,306	139,979
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	**60,492**	59,426	58,813
Allowance for equity funds used during construction	**(623)**	(573)	(297)
Changes in components of working capital	**(5,909)**	(1,411)	217
Other	**2,912**	406	45
Total adjustments	**56,872**	57,848	58,778
Net cash provided by operating activities	**192,579**	194,154	198,757
Cash flows used in investing activities:			
Capital expenditures	**(31,269)**	(27,054)	(21,592)
Other	**646**	(722)	(982)
Net cash used in investing activities	**(30,623)**	(27,776)	(22,574)
Cash flows used in financing activities:			
Equity contributions from partners	**–**	166,000	–
Distributions to partners	**(166,367)**	(165,903)	(209,792)
Proceeds from issuance of debt	**–**	–	128,000
Repayment of debt	**–**	(166,000)	(108,000)
Debt issuance costs	**–**	–	(150)
Net cash used in financing activities	**(166,367)**	(165,903)	(189,942)
Net change in cash and cash equivalents	**(4,411)**	475	(13,759)
Cash and cash equivalents at beginning of year	**14,010**	13,535	27,294
Cash and cash equivalents at end of year	**$ 9,599**	14,010	13,535
Supplemental disclosure for cash flow information:			
Cash paid for interest, net of amount capitalized	**$ 19,098**	21,301	26,746
Accruals for property, plant and equipment	**1,479**	2,592	63
Changes in components of working capital:			
Accounts receivable	**$ (903)**	(1,254)	(973)
Related party receivables	**(222)**	454	(1,163)
Materials and supplies	**(396)**	511	(78)
Prepaid expenses and other	**(167)**	319	374
Accounts payable	**(5,834)**	(1,702)	3,369
Related party payables	**2,119**	709	318
Accrued taxes other than income	**(303)**	(676)	520
Accrued interest	**40**	(15)	(2,150)
Other current liabilities	**(243)**	243	–
Total	**$ (5,909)**	(1,411)	217

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, 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
Net income to partners	67,854	67,853	–	135,707
Changes associated with hedging transactions	–	–	306	306
Distributions to partners	(83,184)	(83,183)	–	(166,367)
Partners' equity at December 31, 2018	$ 382,104	382,105	(963)	763,246

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

NORTHERN BORDER PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2018 AND 2017

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, 2018 and 2017 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) 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 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.

(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, 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 2018 and 2017 were not material to the Partnership's financial statements.

(e) Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered to or received from a pipeline system differs from the amount of natural gas scheduled to be delivered or received. The Partnership values these imbalances due to or from shippers and 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 related party payables. In addition, the Partnership classifies all imbalances as current as the Partnership expects to settle them within a year.

(f) Material and Supplies

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

(g) 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 liability at December 31, 2018 and 2017:

	December 31,		Remaining recovery/ settlement
	2018	2017	period
	(In thousands)		*(Years)*
Regulatory Assets			
Fort Peck right-of-way cost option	**$11,831**	12,149	37
Pipeline extension project	**1,384**	1,845	3
Volumetric fuel tracker	**182**	1,161	(a)
Compressor usage surcharge	**6**	823	(b)
	13,403	15,978	
Less: Current portion included in Prepaid expenses and other	**188**	1,984	
	$13,215	13,994	
Regulatory Liability			
Negative salvage	**$29,598**	27,031	(c)
	$29,598	27,031	

(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(h))

(h) 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 36 years.

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 a regulatory liability in this respect in the balance sheets. 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*. 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 recorded 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.

(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 generated from contractual arrangements for committed capacity and from transportation of natural gas which are treated as a bundled performance obligation. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed. Revenues are invoiced and paid on a monthly basis. The Partnership's pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline systems are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained, as applicable, at the time a regulatory decision becomes final. As of December 31, 2018 and 2017, there are no refund provisions reflected in these financial statements.

(k) 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's 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, 2018 and 2017. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(l) 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 or losses that were accumulated in other comprehensive income related to the hedging relationship.

(m) Debt Issuance Costs

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

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.

(n) Income Taxes

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

(o) 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. Judgment is required in developing these estimates.

3. ACCOUNTING CHANGES

(a) Changes in Accounting Policies for 2018

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 from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Partnership's "performance obligations." The total consideration to which the Partnership expects to be entitled can include fixed and variable amounts. The Partnership has variable revenue that is subject to factors outside the Partnership's influence, such as market volatility, actions of third parties and weather conditions. The Partnership considers this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided. The Partnership has elected to utilize the practical expedient of recognizing revenue as invoiced, also known as the "right to invoice" practical expedient.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and the related cash flows. Effective January 1, 2018, the new guidance was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 9, for further information related to the impact of adopting the new guidance and the Partnership's updated accounting policies related to revenue recognition from contracts with customers.

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 early adopt this guidance and prospectively applied this guidance effective January 1, 2018. The application of this guidance did not have a material impact on its financial statements.

(b) Future Accounting Changes

Leases
In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required 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. 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. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of income. The new guidance does not make extensive changes to lessor accounting.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Partnership will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Partnership will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Partnership will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The Partnership will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard. The Partnership will elect all of the new standard's available transition practical expedients.

The Partnership believes that the most significant effects of adoption relate to the recognition of new ROU assets and lease liabilities on the Partnership's balance sheet for its operating leases and providing significant new disclosures about the Partnership's leasing activities. The guidance will not impact the Partnership's income statement. The Partnership's adoption of this guidance will not have a material impact on its financial statements. The new standard also provides practical expedients for a Partnership's ongoing accounting. The Partnership will elect the short-term lease recognition exemption for all leases. This means, for those leases that qualify, the Partnership will not recognize ROU assets or lease liabilities. The Partnership also currently expects to elect the practical expedient to not separate lease and non-lease components for all leases for which the Partnership is the lessee.

Measurement of Credit Losses on Financial Instruments
In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. The Partnership is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on the Partnership's financial statements.

Fair Value Measurement
In August 2018, the FASB issued new guidance that amends certain disclosure requirements for the fair value measurements as part of its disclosure framework project. This new guidance is effective January 1, 2020; however, early adoption of certain or all requirements is permitted. The Partnership is currently evaluating the impact of adoption of this guidance and has not yet determined the effect on its financial statements.

4. U.S. TAX REFORM IMPACT

On December 22, 2017, the President of the United States signed into law H.R. 1 (the 2017 Tax Act). This legislation provides for major changes to U.S. corporate federal tax law including a reduction of the U.S. federal corporate income tax rate. 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 2017 Tax Act.

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.

2018 FERC Actions

On March 15, 2018, FERC issued (1) a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) to address the treatment of income taxes for ratemaking purposes for Master Limited Partnerships (MLPs), (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact of the federal income tax rate reduction and the Revised Policy Statement could have on a pipeline's Return on Equity (ROE) assuming a single-issue adjustment to a pipeline's rates, and (3) an NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes (ADIT) and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement (Order on Rehearing) dismissing rehearing requests related to the Revised Policy Statement and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR. On November 15, 2018, FERC issued a policy statement on the Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset a policy statement (Excess ADIT Policy Statement) addressing certain issues raised in the NOI issued last March 15, 2018 (collectively, the "2018 FERC Actions"). Each of the 2018 FERC Actions is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates
The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regard to ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as the refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on FERC Rate Changes for Interstate Natural Gas Companies
The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantifies the isolated rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. Pipelines filing the one-time report will have four options:

- Option 1: make a limited Natural Gas Act (NGA) Section 4 filing to reduce its rates by the reduction in its cost of service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G shows the pipeline's estimated ROE as being 12 percent or less. Under the Final Rule and notwithstanding the Revised Policy Statement, a pipeline organized as an MLP is not required to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance, along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base used for rate-making purposes;
- Option 2: commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. If the pipeline commits to file by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it does not believe the pipeline's rates must change; and
- Option 4: take no other action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

On December 6, 2018, the Partnership filed its respective FERC Form No. 501-G and elected Option 1 (see further discussion below).

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates
In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, is required by FERC related to the ADIT that were reserved in anticipation of being paid to the Internal Revenue Service (IRS), but which no longer accurately reflect the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated rates or earnings.

As noted above, FERC's Order on Rehearing provided guidance with regard to ADIT for MLP pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

The Excess ADIT Policy Statement also addressed how to disclose reversals of ADIT account balances in FERC's annual financial report filings. The policy statement also stated that, for those pipelines that continue to have an income tax allowance, excess/deficient ADIT associated with an asset that is sold or retired after December 31, 2017 must continue to be amortized in rates even after the sale or retirement of the asset.

2017 Rate Case and subsequent limited section 4 rate reductions
The Partnership operates on rates approved by FERC effective January 1, 2018 (2017 Settlement). The 2017 Settlement provided for tiered rate reductions from January 1, 2018 to December 31, 2019 that equates to an overall rate reduction of 12.5% by January 1, 2020 (10.5% by December 31, 2019 and 2% by January 1, 2020). The 2017 Settlement did not contain a moratorium and the Partnership is required to file new rates effective July 1, 2024. Effective for 2019, FERC approved an additional 2% rate reduction and elimination of the Partnership's tax allowance and ADIT liability from rate base pursuant to its limited Section 4 filing (Option 1). The removal of ADIT increased the net recoverable rate base and mitigated the loss of the Partnership's tax allowance. The Partnership is in discussion with customers to extend the additional 2% rate reduction beyond 2019.

Compressor Usage Surcharge

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, 2018 and 2017, the Partnership had recorded nil and $0.8 million as prepaid expenses other, respectively, on the accompanying balance sheets for the net over recoveries of compressor usage related costs.

(c) Commitments

The Partnership makes payments under a non-cancelable lease on office space and right-of-way commitments. The Partnership's expense incurred for these commitments was $3.0 million for each of the years ended December 31, 2018, 2017, and 2016, respectively. The Partnership's future minimum payments on these arrangements are as follows:

Year Ending (In thousands)	Right-of-Way	Office Space	Total
2019	2,215	28	2,243
2020	2,232	28	2,260
2021	2,567	28	2,595
2022	2,568	28	2,596
2023	2,569	28	2,597
Thereafter	37,375	57	37,432
	$49,526	$197	$49,723

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 commitment 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)	**2018**	2017
2011 Credit Agreement – average interest rate of 3.475% at December 31, 2018 due 2020	**$15,500**	15,500
2001 Senior Notes – 7.50%, due 2021	**250,000**	250,000
Unamortized debt discount	**(143)**	(188)
Unamortized debt expense	**(902)**	(1,256)
	$264,455	264,056

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 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 December 31, 2018, 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 1.00. 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 1.00 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, 2018, 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 2019, 2022, or 2023.

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, 2018, the Partnership reclassified the below amounts from AOCL into earnings for these terminated derivatives.

Net Loss Reclassified from AOCL into Income (Effective Portion) *(In thousands)*	Statements of Income Caption	Years Ended December 31, **2018**	2017	2016
Cash flow hedges	Interest expense	**$(306)**	(285)	(264)

At December 31, 2018 and 2017, AOCL was $1.0 million and $1.3 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 2019. The Partnership had no other derivative instruments during the period ended December 31, 2018.

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, 2018 and 2017. 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.

	2018		2017	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial asset:				
Cash and cash equivalents	**$9,599**	**9,599**	14,010	14,010
Financial liability:				
Long-term debt	**$265,500**	**286,250**	265,500	294,154

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, which is classified as Level 1 in the "Fair Value Hierarchy".

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, 2018 and 2017:

	2018		2017	
(In thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Natural gas imbalance asset	**$604**	**604**	815	815
Natural gas imbalance liability	**429**	**429**	1,232	1,232
Related party natural gas imbalance liability	**$293**	**293**	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. REVENUES

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for all periods in 2018 reflect the application of the new guidance, while the reported results for all periods in 2017 and 2016 were prepared under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP".

(a) Disaggregation of Revenues

For the year ended December 31, 2018, virtually all of the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2(i).

(b) Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Partnership adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Partnership is not required to analyze completed contracts at the date of adoption. The adoption of the new guidance did not have a material impact on the Partnership's previously reported financial statements at December 31, 2017.

(c) Pro-forma Financial Statements under Legacy U.S. GAAP

At December 31, 2018, had legacy U.S. GAAP been applied, there would be no change in the Partnership's reported balance sheet and income statement line items.

(d) Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under Accounts receivable in the balance sheet. Additionally, our accounts receivable represents the Partnership's unconditional right to recognize revenue for services completed which includes billed and unbilled accounts.

(e) Future Revenue from Remaining Performance Obligations

When the right to invoice practical is applied, the guidance does not require disclosure of information related to future revenue from remaining performance obligations therefore no additional disclosure is required.

Additionally, in the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied.

10. TRANSACTIONS WITH MAJOR CUSTOMERS

For the year ended December 31, 2018, shippers providing significant operating revenues to the Partnership were Tenaska Marketing Ventures, ONEOK Rockies Midstream, L.L.C. (ONEOK Rockies), a subsidiary of ONEOK, Sequent Energy Management, and BP Canada with revenues of $38.7 million, $29.4 million, $27.8 million, and $27.5 million, respectively. At December 31, 2018, Tenaska Marketing Ventures and ONEOK Rockies, owed the Partnership approximately $4.2 million and $3.2 million, respectively, which is greater than 10 percent of the Partnership's trade accounts receivable.

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.

11. 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, 2018, 2017, and 2016, the Partnership's charges from TransCanada and its affiliates totaled approximately $35.6 million, $43.3 million, and $32.0 million, respectively. The impact of these charges on the Partnership's income was $32.2 million, $31.3 million, and $24.4 million, respectively. At December 31, 2018 and 2017, the Partnership owed $3.3 million and $3.6 million, respectively, to these affiliates classified to related party accounts on the balance sheets.

For the years ended December 31, 2018, 2017, and 2016, the Partnership had contracted firm capacity held by one customer affiliated with one of the Partnership's general partners. Revenues from ONEOK Rockies for 2018, 2017, and 2016 were $29.4 million, $31.5 million, and $28.4 million, respectively. At December 31, 2018 and 2017, the Partnership had outstanding receivables from ONEOK Rockies of $3.2 million and $2.8 million, respectively.

12. 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 has the responsibility to determine 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, 2018, 2017, and 2016, the Partnership paid distributions to its general partners of $166.4 million, $165.9 million, and $209.8 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.

13. SUBSEQUENT EVENTS

On January 7, 2019, the Partnership declared a cash distribution in the amount of $18.5 million. The distribution was paid on January 31, 2019.

On February 14, 2019, the Partnership declared a cash distribution in the amount of $20 million. The distribution will be paid on February 28, 2019.

Subsequent events have been assessed through February 15, 2019, which is the date the financial statements were issued, and we concluded there were no events or transactions during this period that would require recognition or disclosure in the financial statements other than those already reflected.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
INDEPENDENT AUDITORS' REPORT

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

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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 15, 2019

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
BALANCE SHEETS

December 31, 2018 and 2017 (In Thousands)	2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$ 49	44
Demand loan receivable from affiliate (*Note 8(a)*)	35,934	64,040
Accounts receivable:		
Trade	8,582	7,409
Affiliates	18,754	20,236
Materials and supplies	9,951	9,689
Other	1,504	5,356
Total current assets	74,774	106,774
Property, plant, and equipment:		
Property, plant, and equipment	2,116,001	2,105,808
Construction work in progress	7,741	1,330
	2,123,742	2,107,138
Less accumulated depreciation and amortization	(1,434,748)	(1,406,348)
Total property, plant, and equipment, net	688,994	700,790
Total assets	$ 763,768	807,564
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable:		
Trade	$ 5,628	8,095
Affiliates	3,815	4,919
Provision for revenue sharing refund *(Note 9)*	–	39,601
Provision for rate refund (*Note 4(b)*)	–	7,972
Current maturities of long-term debt	21,000	19,000
Taxes payable (other than income)	8,184	7,916
Accrued interest	5,912	6,240
Other current liabilities	2,389	–
Total current liabilities	46,928	93,743
Long-term debt, net of current maturities	218,782	239,753
Regulatory liabilities	3,664	744
Other noncurrent liabilities	220	212
Partners' capital	494,174	473,112
Total liabilities and partners' capital	$ 763,768	807,564

See accompanying notes to financial statements.

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

Years ended December 31, 2018, 2017, and 2016 (In Thousands)	**2018**	2017	2016
Operating revenues, *net (Note 9)*	**$ 245,646**	181,487	179,133
Operating expenses:			
Operation and maintenance	**56,613**	54,885	58,048
Depreciation and amortization	**31,813**	29,474	27,911
Taxes, other than income	**11,651**	10,830	10,872
Total operating expenses	**100,077**	95,189	96,831
Operating income	**145,569**	86,298	82,302
Other income, net	**371**	480	521
Interest and debt expense	**(19,194)**	(20,831)	(22,295)
Affiliated interest income	**916**	372	114
Net income	**$ 127,662**	66,319	60,642
Partners' capital:			
Balance at beginning of year	**$ 473,112**	462,293	484,951
Net income	**127,662**	66,319	60,642
Distributions to partners	**(125,600)**	(74,500)	(102,300)
Contributions from partners	**19,000**	19,000	19,000
Balance at end of year	**$ 494,174**	473,112	462,293

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
STATEMENTS OF CASH FLOWS

Years ended December 31, 2018, 2017, and 2016 (In Thousands)	**2018**	2017	2016
Cash flows from operating activities:			
Net income	**$ 127,662**	66,319	60,642
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**31,813**	29,474	27,911
Allowance for funds used during construction, equity	**(308)**	(116)	(263)
Amortization of debt issuance cost, reported as part of interest expense	**29**	41	82
Asset and liability changes:			
Accounts receivable	**309**	(1,109)	(4,437)
Other current assets	**3,590**	(2,608)	321
Accounts payable	**(3,207)**	(1,792)	1,043
Provision for revenue sharing refund	**(44,722)**	32,401	5,300
Provision for rate refund	**(2,851)**	7,972	–
Other current liabilities	**2,329**	(3,144)	2,712
Noncurrent liabilities	**8**	(14)	(9)
Net cash provided by operating activities	**114,652**	127,424	93,302
Cash flows from (used in) investing activities:			
Additions to property, plant, and equipment	**(17,178)**	(13,814)	(14,885)
Net change in demand loan receivable from affiliate	**28,106**	(36,896)	23,928
Other	**25**	(2,209)	(54)
Net cash provided by (used in) investing activities	**10,953**	(52,919)	8,989
Cash flows used in financing activities:			
Payments for retirement of long-term debt	**(19,000)**	(19,000)	(19,000)
Distributions to partners	**(125,600)**	(74,500)	(102,300)
Contributions from partners	**19,000**	19,000	19,000
Net cash used in financing activities	**(125,600)**	(74,500)	(102,300)
Net change in cash and cash equivalents	**5**	5	(9)
Cash and cash equivalents at beginning of year	**44**	39	48
Cash and cash equivalents at end of year	**$ 49**	44	39
Supplemental cash flow information:			
Interest paid, net of capitalized interest	**$ 19,599**	20,791	22,529
Accruals for property, plant and equipment	**$ 1,886**	1,497	–

See accompanying notes to financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2018 AND 2017

(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, 2018 and 2017 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, 2018 and 2017:

	December 31,		Remaining recovery/ settlement period
	2018	2017	
	(In thousands)		*(Years)*
Regulatory Assets			
Volumetric fuel tracker	–	2,787	(a)
Less: Current portion included in Other	–	2,787	
	$ –	–	
Regulatory Liabilities			
Negative salvage	**$ 3,664**	744	(b)
Volumetric fuel tracker	**2,389**	–	(a)
	6,053	744	
Less: Current portion included in Other	**2,389**	–	
	$ 3,664	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 2(h)).

(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 2018 and 2017.

(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 depreciation rates approved by FERC in the Partnership's last rate proceeding. 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 6 to 44 years.

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*. 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 recorded 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 generated from contractual arrangements for committed capacity and from transportation of natural gas. These are treated as a bundled performance obligation. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed. Revenues are invoiced and paid monthly. The Partnership's pipeline systems do not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline systems are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained, as applicable, at the time a regulatory decision becomes final.

(i) 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 fair value of a liability for an asset retirement obligation is recorded during the period in which the liability is incurred and 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 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, 2018 and 2017. The Partnership continues to evaluate its asset retirement obligations and future developments that could impact amounts it records.

(k) Income Taxes

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

(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) 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. Judgment is required in developing these estimates.

(3) ACCOUNTING CHANGES

Effective January 1, 2018

Revenue from contracts with customers
In 2014, the Financial Accounting Standards Board (FASB) issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Partnership's "performance obligations." The total consideration to which the Partnership expects to be entitled can include fixed and variable amounts. The Partnership has variable revenue that is subject to factors outside the Partnership's influence, such as market volatility, actions of third parties and weather conditions. The Partnership considers this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided. The Partnership has elected to utilize the practical expedient of recognizing revenue as invoiced, also known as the "right to invoice" practical expedient.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and the related cash flows. Effective January 1, 2018, the new guidance was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 8 – Revenues, for further information related to the impact of adopting the new guidance and the Partnership's updated accounting policies related to revenue recognition from contracts with customers.

Future Accounting Changes

Leases
In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required 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. 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. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of income.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Partnership will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Partnership will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Partnership will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The Partnership will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard. The Partnership will elect all of the new standard's available transition practical expedients.

The Partnership believes that the most significant effects of adoption will relate to the recognition of new ROU assets and lease liabilities on the Partnership's balance sheet for its operating leases and providing significant new disclosures about the Partnership's leasing activities. The guidance will not impact the Partnership's income statement. The Partnership's adoption of this guidance will not have a material impact on its financial statements. The new standard also provides practical expedients for the Partnership's ongoing accounting. The Partnership currently will elect the short-term lease recognition exemption for all leases. This means, for those leases that qualify, the Partnership will not recognize ROU assets or lease liabilities.

Measurement of Credit Losses on Financial Instruments
In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. The Partnership is currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on the Partnership's financial statements.

Fair Value Measurement
In August 2018, the FASB issued new guidance that amends certain disclosure requirements for the fair value measurements as part of its disclosure framework project. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Partnership is currently evaluating the impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

(4) U.S TAX REFORM IMPACT

On December 22, 2017, the President of the United States signed into law H.R. 1 (the 2017 Tax Act). This legislation provides for major changes to U.S. corporate federal tax law including a reduction of the federal corporate income tax rate. As a Delaware 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 2017 Tax Act.

(5) COMMITMENTS AND CONTINGENCIES

(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) Legal Proceedings

In 2009, the Partnership filed suit in the U.S. District Court, District of Minnesota, against Essar Steel Minnesota LLC (Essar Minnesota) and certain Foreign Essar Affiliates (collectively, Essar) for breach of Essar's 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. Following the Partnership's several attempts at recovering the payments through the Federal court system, Essar Minnesota subsequently filed for bankruptcy in 2016 and a performance bond was released into the bankruptcy court proceedings. In 2018, the Partnership came to an agreement for an allowed claim and the bankruptcy court approved the Partnership's claim in the amount of $31.5 million.

The Foreign Essar Affiliates have not filed for bankruptcy and the Partnership's case against the Foreign Essar Affiliates in Minnesota state court remains pending.

At December 31, 2018, the Partnership is unable to estimate the timing or the extent to which its claims in bankruptcy and state court will be recoverable, therefore, the Partnership did not recognize any gain contingency on its outstanding claim against Essar and the Essar Foreign Affiliates. Additionally, the Partnership has concluded that the future recovery on this claim is remote.

Finally, at December 31, 2018 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.

(c) Regulatory Matters

On March 15, 2018, FERC issued (1) a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) to address the treatment of income taxes for ratemaking purposes for Master Limited Partnerships (MLPs), (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact that the U.S. federal income tax rate reduction and the Revised Policy Statement could have on a pipeline's Return on Equity (ROE) assuming a single-issue adjustment to a pipeline's rates, and (3) a NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes (ADIT) and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement (Order on Rehearing) dismissing rehearing requests related to the Revised Policy Statement and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR. On November 15, 2018, FERC issued a policy statement on the Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset, a policy statement (Excess ADIT Policy Statement) addressing certain issues raised in the NOI issued March 15, 2018 (collectively, the "2018 FERC Actions"). Each of the 2018 FERC Actions is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates
The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regard to ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as the refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on FERC Rate Changes for Interstate Natural Gas Companies
The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantifies the isolated rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. Pipelines filing the one-time report will have four options:

- Option 1: make a limited Natural Gas Act (NGA) Section 4 filing to reduce its rates by the reduction in its cost of service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G shows the pipeline's estimated ROE as being 12 percent or less. Under the Final Rule and notwithstanding the Revised Policy Statement, a pipeline organized as an MLP is not required to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance, along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base used for rate-making purposes;
- Option 2: commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. If the pipeline commits to file by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date;
- Option 3: file a statement explaining its rationale for why it does not believe the pipeline's rates must change; or
- Option 4: take no other action. FERC would then consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

The Partnership filed its respective FERC Form No. 501-G on December 6, 2018 and elected Option 1 (see further discussion below).

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates
In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, is required by FERC related to the ADIT that were reserved in anticipation of being paid to the Internal Revenue Service (IRS), but which no longer accurately reflect the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated cost-of-service rates or earnings.

As noted above, FERC's Order on Rehearing provided guidance with regard to ADIT for MLP pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

The Excess ADIT Policy Statement also addressed how to disclose reversals of ADIT account balances in FERC's annual financial report filings. The policy statement also stated that, for those pipelines that continue to have an income tax allowance, excess/deficient ADIT associated with an asset that is sold or retired after December 31, 2017 must continue to be amortized in rates even after the sale or retirement of the asset.

2017 Rate Case and subsequent limited section 4 rate reduction

The Partnership operates under a settlement approved by FERC effective January 1, 2018 (2017 Great Lakes Settlement). The 2017 Great Lakes Settlement did not contain a moratorium and eliminated its revenue sharing mechanism with customers. The Partnership is required to file new rates effective October 1, 2022. Under the terms of the 2017 Settlement, the revenue sharing mechanism was eliminated. Additionally, 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.

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 and refunded in the first quarter of 2018.

Effective February 1, 2019, FERC approved an additional 2% rate reduction and elimination of its tax allowance and ADIT liability from rate base pursuant to the Partnership's limited Section 4 filing (Option 1). The removal of ADIT increases net recoverable rate base and mitigated the loss of the Partnership's tax allowance.

(d) 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 expired during the second quarter of 2018 on approximately 7.6 miles of pipeline. The Partnership is negotiating to renew the rights-of-way with the tribal authorities and continues to operate the pipeline during its good faith negotiations to renew these agreements. During the second quarter of 2018, the Partnership began accruing the estimated costs and the associated liability related to these pending agreements and has accrued approximately $1.4 million at December 31, 2018 classified as Other current liabilities in the Balance Sheet.

(6) LONG-TERM DEBT

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

(In thousands)	**2018**	2017
6.73% series Senior Notes due 2016 to 2018	**$–**	9,000
9.09% series Senior Notes due 2016 to 2021	**30,000**	40,000
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
Less: Unamortized debt issuance costs	**218**	247
	239,782	258,753
Less: current maturities	**21,000**	19,000
Total long-term debt, net	**$218,782**	239,753

The aggregate annual required repayment of long-term debt is $21.0 million per year for 2019 and 2020, $31.0 million for 2021, and $21.0 million for 2022. Aggregate required repayments of long-term debt thereafter total $146.0 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 $129.2 million of partners' capital was restricted as to distributions as of December 31, 2018. As of December 31, 2018, 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 represents carrying amounts and estimated fair values of the Partnership's financial instruments at December 31, 2018 and 2017. 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, which is classified as Level 1.

Demand loan receivable – The carrying amount of the demand loan receivable approximates fair value due to the short maturity of these investments, which is classified as Level 1.

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, 2018 the carrying value of the long-term debt is $240 million and the fair value amount is $288 million. At December 31, 2017 the carrying value of the long-term debt is $259 million and the fair value amount is $335 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, 2018 and 2017:

	2018		2017	
(In thousands)	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Affiliate natural gas imbalance asset	**$882**	**882**	325	325
Natural gas imbalance asset	**$2,829**	**2,829**	343	343
Affiliate natural gas imbalance liability	**$486**	**486**	1,796	1,796
Natural gas imbalance liability	**$1,048**	**1,048**	3,089	3,089

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, 2018 and 2017, the Partnership had a demand loan receivable from TransCanada of $35.9 million and $64.0 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 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.

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

(In thousands)	**2018**	2017	2016
Transportation revenues from affiliates[a]	**$178,366**	130,165	127,932
Cost recovery from affiliates[b]	**1,332**	1,556	1,680
Costs charged from affiliates	**43,737**	35,381	30,100

[a] Transportation revenues from affiliates represent the amount recognized by the Partnership before any allowance on revenue sharing and provision for rate refund, which represent 73%, 57% and 68%, of the Partnership's total revenues for the year ended December 31, 2018, 2017 and 2016, respectively.

[b] Cost recovery from affiliates represents the Partnership's recovery of a portion of the costs of the facility it owns by charging its affiliates for use of office space in Troy, Michigan.

The Partnership has a long-term transportation agreement with TransCanada's Canadian Mainline (Canadian Mainline) that commenced on November 1, 2017 for a ten-year period that allows TransCanada to transport up to 0.711 billion cubic feet of natural gas per day. This contract, which contains volume reduction options up to full contract quantity beginning in year three, was a direct benefit from TransCanada's long-term fixed price service on its Canadian Mainline that was launched in 2017. During the years ended December 31, 2018 and 2017, the Partnership recognized transportation revenue of $75.8 million and $13.0 million, respectively related to this contract.

During the year-ended December 31, 2018, the Partnership's remaining $102.6 million of transportation revenues from affiliates was associated with its other transportation contracts with Canadian Mainline amounting to $48.6 million and another affiliate, TransCanada's ANR Pipeline Company (ANR) amounting to $54.0 million.

During the second quarter of 2018, the Partnership reached an agreement on the terms of a new long-term transportation capacity contracts with ANR. The contracts are for a term of 15 years from November 2021 to October 31, 2036 with a total contract value of approximately $1.3 billion. The contracts contain reduction options (i) at anytime on or before April 1, 2019 for any reason and (ii) anytime before April 2021, if ANR is not able to secure the required regulatory approval related to anticipated expansion projects.

(9) REVENUES

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for all periods in 2018 reflect the application of the new guidance, while the reported results for all periods in 2017 and 2016 were prepared under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP".

Disaggregation of Revenues

For the year ended December 31, 2018, virtually all the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2 – Significant Accounting Policies.

Revenues Subject to Refund

Also noted under Note 2 – Significant Accounting Policies, a portion of our revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. The Partnership uses its best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue we recognized.

During the year ended December 31, 2017 and 2016, the Partnership operated under a FERC approved 2013 rate settlement that included a revenue sharing mechanism that requires the Partnership to 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 and 2016 were net of $39.6 million and $7.2 million estimated revenue sharing provision, respectively. As discussed under Note 5(b), beginning in 2018, the revenue sharing mechanism was eliminated as part of the 2017 Settlement.

Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Partnership adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Partnership is not required to analyze completed contracts at the date of adoption. The adoption of the new guidance did not have a material impact on the Partnership's previously reported financial statements at December 31, 2017.

Pro-forma Financial Statements under Legacy U.S. GAAP

At December 31, 2018, had legacy U.S. GAAP been applied, there would be no change in the Partnership's reported balance sheet and income statement line items.

Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under Accounts receivable in the balance sheet. Additionally, our accounts receivable represents the Partnership's unconditional right to recognize revenue for services completed which includes billed and unbilled accounts.

Future Revenue from Remaining Performance Obligations

When the right to invoice practical expedient is applied, the guidance does not require disclosure of information related to future revenue from remaining performance obligations therefore no additional disclosure is required.

Additionally, in the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the capacity contracted and variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied.

(10) DISTRIBUTIONS

The Partnership's distribution policy generally results in a quarterly cash distribution equal to 100 percent 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 15, 2019, the Management Committee of the Partnership declared a cash distribution in the amount of $36.2 million to the partners. The distribution was paid on February 1, 2019.

(11) SUBSEQUENT EVENTS

Subsequent events have been assessed through February 15, 2019, 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.

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.
INDEPENDENT AUDITORS' REPORT

To the Partners of Iroquois Gas Transmission System, L.P.:

We have audited the accompanying consolidated financial statements of Iroquois Gas Transmission System, L.P., and its subsidiaries (the Partnership), which comprise the consolidated balance sheets as of December 31, 2018 and 2017, and the related consolidated statements of comprehensive income, changes in partners' equity and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of consolidated 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 consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated 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 consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Iroquois Gas Transmission System, L.P., and its subsidiaries as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

Blum, Shapiro & Company, P.C.

Blum, Shapiro & Company, P.C.
West Hartford, Connecticut
February 19, 2019

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (thousands of dollars)	**2018**	2017	2016
Operating revenues (Notes 7, 8, 9, and 10)	**$193,780**	$193,460	$195,212
Operating expenses:			
Operation and maintenance (Note 2 and 12)	**29,158**	27,900	30,644
Depreciation and amortization (Note 3)	**29,177**	28,849	34,917
Taxes other than income taxes	**27,628**	27,348	27,344
Total operating expenses	**85,963**	84,097	92,905
Operating income	**107,817**	109,363	102,307
Other income / (expenses):			
Interest income	**911**	332	114
Allowance for equity funds used during construction	**2,098**	2,210	2,101
Other, net (Note 2 and 12)	**1,216**	(714)	604
	4,225	1,828	2,819
Interest expense:			
Interest expense	**19,203**	19,522	19,881
Allowance for borrowed funds used during construction	**(1,009)**	(924)	(884)
	18,194	18,598	18,997
Net income	**$93,848**	$92,593	$86,129
Other comprehensive (loss)/income – effects of retirement benefit plans (Note 11)	**(2,521)**	1,830	(38)
Comprehensive income	**$91,327**	$94,423	$86,091

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.
CONSOLIDATED BALANCE SHEETS

At December 31 (thousands of dollars)	**2018**	2017
Assets		
Current Assets:		
Cash and temporary cash investments	**$ 80,393**	$ 85,595
Accounts receivable – trade	**17,106**	20,720
Prepaid property taxes	**10,722**	10,450
Other current assets	**4,164**	5,260
Total Current Assets	**$ 112,385**	$ 122,025
Natural Gas Transmission Plant:		
Natural gas plant in service	**1,296,895**	1,286,936
Construction work in progress	**55,495**	48,003
	1,352,390	1,334,939
Accumulated depreciation and amortization	**(771,344)**	(743,899)
Net Natural Gas Transmission Plant (Note 3)	**581,046**	591,040
Other Assets and Deferred Charges:		
Other assets and deferred charges	**7,336**	7,885
Total Other Assets and Deferred Charges	**7,336**	7,885
Total Assets	**$ 700,767**	$ 720,950
Liabilities and Partners' Equity		
Current Liabilities:		
Accounts payable	**$ 3,483**	$ 1,255
Accrued interest	**1,953**	1,993
Current portion of long-term debt (Note 4)	**146,000**	4,000
Customer deposits	**11,091**	10,684
Other current liabilities	**2,742**	3,450
Total Current Liabilities	**$ 165,269**	$ 21,382
Long-Term Debt (Note 4)	**179,000**	325,000
Other Non-Current Liabilities:		
Other non-current liabilities	**13,607**	8,756
Other Non-Current Liabilities	**13,607**	8,756
Commitments and Contingencies (Note 7)		
Total Liabilities	**357,876**	355,138
Partners' Equity	**342,891**	365,812
Total Liabilities and Partners' Equity	**$ 700,767**	$ 720,950

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 *(thousands of dollars)*	**2018**	2017	2016
Cash flows from operating activities:			
Net Income	**$ 93,848**	$ 92,593	$ 86,129
Adjusted for the following:			
Depreciation and amortization	**29,177**	28,849	34,917
Allowance for equity funds used during construction	**(2,098)**	(2,210)	(2,101)
Other assets and deferred charges	**1,548**	(1,100)	(913)
Other non-current liabilities	**1,331**	4,814	637
Changes in working capital:			
Accounts receivable	**3,614**	(1,884)	(1,786)
Prepaid property taxes	**(272)**	20	84
Other current assets	**(168)**	(259)	(9)
Accounts payable	**381**	(1,367)	1,066
Customer deposits	**407**	151	442
Accrued interest	**(40)**	(60)	(56)
Other current liabilities	**556**	(231)	(356)
Net cash provided by operating activities	**128,284**	119,316	118,054
Cash flows from investing activities:			
Capital expenditures	**(15,238)**	(14,067)	(13,424)
Net cash used for investing activities	**(15,238)**	(14,067)	(13,424)
Cash flows from financing activities:			
Partner distributions	**(114,248)**	(100,476)	(90,000)
Repayments of long-term debt	**(4,000)**	(5,500)	(5,500)
Net cash used for financing activities	**(118,248)**	(105,976)	(95,500)
Net (decrease)/increase in cash and temporary cash investments	**(5,202)**	(727)	9,130
Cash and temporary cash investments at beginning of year	**85,595**	86,322	77,192
Cash and temporary cash investments at end of year	**$ 80,393**	$ 85,595	$ 86,322
Supplemental disclosure of cash flow information:			
Cash paid for interest	**$ 18,874**	$ 19,192	$ 19,523
Accounts payable accruals for capital expenditures	**$ 2,161**	$ 314	$ 308

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY

(thousands of dollars)	Net Income	Distributions to Partners	Contributions by Partners	Accumulated Other Comprehensive (Loss)/Income	Total Partners' Equity
December 31, 2015					
Balance	$1,416,115	$(1,316,544)	$279,381	$(3,178)	$375,774
Net Income	86,129	–	–	–	86,129
Equity Distributions to Partners (Note 1)	–	(90,000)	–	–	(90,000)
Other Comprehensive Loss (Note 11)	–	–	–	(38)	(38)
December 31, 2016					
Balance	$1,502,244	$(1,406,544)	$279,381	$(3,216)	$371,865
Net Income	92,593	–	–	–	92,593
Equity Distributions to Partners (Note 1)	–	(100,476)	–	–	(100,476)
Other Comprehensive Income (Note 11)	–	–	–	1,830	1,830
December 31, 2017					
Balance	$1,594,837	$(1,507,020)	$279,381	$(1,386)	$365,812
Net Income	93,848	–	–	–	93,848
Equity Distributions to Partners (Note 1)	–	(114,248)	–	–	(114,248)
Other Comprehensive Loss (Note 11)	–	–	–	(2,521)	(2,521)
December 31, 2018					
Balance	$1,688,685	$(1,621,268)	$279,381	$(3,907)	$342,891

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

IROQUOIS GAS TRANSMISSION SYSTEM, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF PARTNERSHIP:

Iroquois Gas Transmission System, L.P., (the Partnership or Iroquois) is a Delaware limited partnership that owns and operates a natural gas transmission pipeline from the Canada-United States border near Waddington, NY, to South Commack, Long Island, NY and Hunt's Point, Bronx, New York. In accordance with the limited partnership agreement, the Partnership shall continue in existence until October 31, 2089, and from year to year thereafter, until the partners elect to dissolve the Partnership and terminate the limited partnership agreement.

Effective April 1, 2016, TCPL Northeast Ltd. (TransCanada PipeLines) acquired ownership interests formerly owned by TEN Transmission Company (Avangrid) (4.87%). On May 1, 2016 TCPL Northeast Ltd. (TransCanada PipeLines) acquired ownership interests of 0.65% from Dominion Iroquois, Inc. (Dominion Energy).

On June 1, 2017, TCPL Northeast Ltd. and TransCanada Iroquois Ltd. sold its 21.00% and 28.34% interest in the Partnership, respectively, to its affiliate, TC PipeLines Intermediate Limited Partnership (TCILP) for a total 49.34% interest in the Partnership. TransCanada's Master Limited Partnership, TC PipeLines, LP is TCILP's parent.

As of December 31, 2018, the partners consist of TC PipeLines Intermediate Limited Partnership (TC PipeLines, LP) (49.34%), Iroquois GP Holding Company, LLC (Dominion Energy Midstream) (25.93%), Dominion Iroquois, Inc. (Dominion Energy) (24.07%), and TransCanada Iroquois Ltd. (TransCanada PipeLine USA Ltd.) (0.66%). Iroquois Pipeline Operating Company, a wholly-owned subsidiary, is the administrative operator of the pipeline. IGTS, Inc. of Connecticut is an additional wholly owned subsidiary formed to hold title to certain Connecticut property interests.

Income and expenses are allocated to the partners and credited to their respective equity accounts in accordance with the partnership agreements and their respective percentage interests. Distributions to partners are made concurrently to all partners in proportion to their respective partnership interests. The Partnership made cash distributions to partners of $114.2 million in 2018, which includes $21.0 million of surplus cash distributions, and $100.5 million in 2017, which includes $10.4 million of surplus cash distributions (Refer to Note 7). The Partnership made cash distributions to partners of $90.0 million in 2016.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Basis of Presentation

The consolidated financial statements of the Partnership are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The Partnership's natural gas pipeline is subject to regulation by the Federal Energy Regulatory Commission (FERC). Generally accepted accounting principles for regulated entities allow the Partnership to give accounting recognition to the actions of regulatory authorities. In accordance with GAAP, the Partnership has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or an obligation relieved in the future through the rate-making process.

Principles of Consolidation

The consolidated financial statements include the accounts of the Partnership, Iroquois Pipeline Operating Company and IGTS, Inc. of Connecticut. Intercompany transactions have been eliminated in consolidation.

Cash and Temporary Cash Investments

The Partnership considers all highly liquid temporary cash investments purchased with an original maturity date of three months or less to be cash equivalents.

Natural Gas Plant In Service

Natural gas plant in service is carried at original cost. The majority of the natural gas plant in service is categorized as natural gas transmission plant. Natural gas transmission plant assets are depreciated at 2.77% through August 31, 2016. Effective September 1, 2016, as a result of the rate case (refer to Note 7) the rate for transmission plant assets has been changed to a range of 1.7% to 2.95%. The rate for general plant assets which includes primarily vehicles, leasehold improvements and computer equipment has been reduced from 20.0% to a range of 1.9% to 12.0%. The rates for intangible plant assets has been reduced from 2.77% to a range of 0.35% to 2.0%.

Construction Work In Progress

At December 31, 2018 and December 31, 2017 construction work in progress primarily included preliminary construction costs relating to the Wright Interconnect (WIP) Project. The Partnership also has commitments of approximately $2.4 million relating to the WIP Project at December 31, 2018.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) represents the cost of funds used to finance natural gas transmission plant under construction. The AFUDC rate includes a component for borrowed funds as well as equity. The AFUDC is capitalized as an element of natural gas plant in service.

Revenue Recognition

The Partnership's revenues are generated from contractual arrangements for committed capacity and from transportation of natural gas which are treated as a bundled performance obligation. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed. Revenues are invoiced and paid monthly. The Partnership's pipeline system does not take ownership of the natural gas that is transported for customers. Revenues from contracts with customers are recognized net of any taxes collected from customers, which are subsequently remitted to governmental authorities.

The Partnership's pipeline system is subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained, as applicable, at the time a regulatory decision becomes final.

Income Taxes

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 the 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.

CT Pass-Through Entity Tax

On May 31, 2018, Connecticut passed legislation establishing a new pass-through entity tax. Iroquois will elect to utilize the alternative tax base which excludes any income attributable to publicly traded partnerships or corporations and therefore will not owe any tax.

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The key estimates include determining the economic useful lives of the Partnership's assets, the fair values used to determine possible asset impairment charges, exposures under contractual indemnifications, calculations of pension expense and various other recorded or disclosed amounts. The Partnership believes that its estimates for these items are reasonable, but cannot assure that actual amounts will not vary from estimated amounts.

Asset Retirement Obligations

The Partnership accounts for asset retirement obligations in accordance with GAAP, which requires entities to record the fair value of a liability for an asset retirement obligation during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. 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 establish a liability for the obligations.

Accounting Pronouncements

Changes in Accounting Policies for 2018

Compensation-Retirement Benefits

In March 2017, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2017-07, Compensation-Retirement Benefits, which improves the presentation of the net periodic pension cost and net periodic postretirement benefit cost. The amendments require that an employer report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit costs are required to be presented in the consolidated statements of comprehensive income separately from the service cost component and outside a subtotal of income from operations. This ASU is effective for public businesses for annual periods beginning after December 15, 2017 and for other entities for annual periods beginning after December 15, 2018. The Partnership has elected early adoption of the amendments for the quarter ended March 31, 2018. The amendments have been retrospectively applied. As a result, service costs of $0.6 million have been reclassified to operation and maintenance expenses from other, net in the consolidated statements of comprehensive income for 2017 and 2016.

Revenue from contracts with customers

In 2014, the Financial Accounting Standards Board (FASB) issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Partnership's performance obligations. The total consideration to which the Partnership expects to be entitled can include fixed and variable amounts. The Partnership has variable revenue that is subject to factors outside the Partnership's influence, such as market volatility, actions of third parties and weather conditions. The Partnership considers this variable revenue to be constrained as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided. The Partnership has elected to utilize the practical expedient of recognizing revenue as invoiced, also known as the right to invoice practical expedient.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and the related cash flows. Effective January 1, 2018, the new guidance was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 10 – Revenues, for further information related to the impact of adopting the new guidance and the Partnership's updated accounting policies related to revenue recognition from contracts with customers.

Future Accounting Changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required 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. 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 consolidated balance sheet for all leases with a term longer than 12 months. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statements of comprehensive income.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Partnership will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Partnership will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Partnership will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019. The Partnership will recognize its cumulative effect transition adjustment, if applicable, as of January 1, 2019.

The Partnership will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard. The Partnership expects to elect all of the new standard's available transition practical expedients.

The Partnership believes that the most significant effects of adoption will relate to the recognition of new ROU assets and lease liabilities on the Partnership's consolidated balance sheet for its operating leases and providing significant new disclosures about the Partnership's leasing activities. The guidance will not impact the Partnership's consolidated statements of comprehensive income. The Partnership's adoption of this guidance will not have a material impact on its consolidated financial statements. The new standard also provides practical expedients for a Partnership's ongoing accounting. The Partnership will elect the short-term lease recognition exemption for all leases. This means, for those leases that qualify, the Partnership will not recognize ROU assets or lease liabilities. The Partnership will also elect the practical expedient to not separate lease and non-lease components for all leases for which the Partnership is the lessee.

Subsequent Events

On January 22, 2019, the Partnership approved a distribution in the amount of $27.6 million. The distribution, which was paid on February 1, 2019, includes its seventh surplus cash distribution in the amount of $5.2 million as discussed in Note 7 – Distributions. As of February 19, 2019, the Partnership has distributed approximately $36.7 million of the expected $57.4 million surplus cash distribution.

The Partnership has evaluated all subsequent events through February 19, 2019, which is the date on which the financial statements were available to be issued.

NOTE 3 NATURAL GAS TRANSMISSION PLANT:

	Balances at December 31,	
(thousands of dollars)	**2018**	**2017**
Classification		
Transmission Plant	**$1,273,929**	$1,266,602
General Plant	**22,966**	20,334
	1,296,895	1,286,936
Less Accumulated Depreciation	**(771,344)**	(743,899)
Construction Work in Progress	**55,495**	48,003
Net Natural Gas Transmission Plant	**$581,046**	$591,040

Depreciation and amortization expense was $29.2 million in 2018, $28.8 million in 2017 and $34.9 million in 2016.

NOTE 4 LONG TERM DEBT:

Detailed information on long-term debt is as follows (thousands of dollars):

	2018	**2017**
At December 31		
Senior Notes – 6.63% due May 2019	**140,000**	140,000
Senior Notes – 4.84% due April 2020	**150,000**	150,000
Senior Notes – 6.10% due August 2027	**35,000**	39,000
Total	**325,000**	329,000
Less Current Maturities of Long-Term Debt	**146,000**	4,000
Long-Term Debt	**179,000**	325,000

The combined schedule of repayments at December 31, 2018 is as follows (millions of dollars):

Year	Scheduled Repayment
2019	$146.0
2020	$153.0
2021	$4.5
2022	$3.0
2023	$4.5
Thereafter	$14.0

The above loans and facilities require the Partnership to maintain compliance with certain restrictive covenants relating to, among other things, certain ratios of indebtedness to total capitalization, and debt service coverage, as defined in the credit agreements and bond indentures. The Partnership is in compliance with these covenants as of and for the years ended December 31, 2018, December 31, 2017 and December 31, 2016.

On June 14, 2018, the $10.0 million revolving credit facility was renewed for 364 days. As of December 31, 2018 there are no amounts outstanding under the revolving credit facility.

On May 13, 2019, the Partnership has $140.0 million of senior notes scheduled to mature which it is in the process of refinancing by issuing new senior unsecured notes by the maturity date.

NOTE 5 CONCENTRATIONS OF CREDIT RISK:

The Partnership's cash and temporary cash investments and trade accounts receivable represent concentrations of credit risk. Management believes that the credit risk associated with cash and temporary cash investments is mitigated by its practice of limiting its investments primarily to commercial paper rated P-1 or higher by Moody's Investors Services and A-1 or higher by Standard and Poor's, and its cash deposits to large, highly-rated financial institutions. Management also believes that the credit risk associated with trade accounts receivable is mitigated by the restrictive terms of the FERC gas tariff that require customers to pay for service within 20 days after the end of the month of service delivery. Also, the Partnership's FERC-approved tariff provides that, subject to certain exceptions, the Partnership has the right to require that shippers have an investment grade rating or obtain a written shipper guarantee from a third party with an investment grade rating, or provide other financial assurances before service can be provided.

NOTE 6 FAIR VALUE OF FINANCIAL INSTRUMENTS:

The fair value amounts disclosed below have been reported to meet the disclosure requirements of GAAP, and are not necessarily indicative of the amounts that the Partnership could realize in a current market exchange.

As of December 31, 2018 and December 31, 2017, the carrying amounts of cash and temporary cash investments, accounts receivable, accounts payable and accrued expenses approximate fair value.

The fair value of long-term debt is estimated by the Partnership's underwriter based on treasury rates and comparable spreads at fiscal year-end. As of December 31, 2018 and December 31, 2017, the carrying amounts and estimated fair values of the Partnership's long-term debt including current maturities were as follows (in thousands of dollars):

Year	**Carrying Amount**	**Fair Value**
2018	**$325,000**	**$332,372**
2017	$329,000	$350,413

NOTE 7 COMMITMENTS AND CONTINGENCIES:

Regulatory Proceedings

Mainline and Eastchester Rate Case Settlement

On January 21, 2016, the FERC opened Docket RP 16-301-000 to examine the appropriateness of the recourse rates charged by the Partnership for both its mainline and Eastchester shippers (2016 Rate Case). On April 5, 2016, the Partnership filed an analysis of its existing revenues and costs with the FERC as required by the January 21, 2016 order. Settlement conferences occurred on April 28, 2016, May 18, 2016, June 1, 2016 and June 16, 2016 which culminated in an agreement in principal resolving the 2016 Rate Case issues (Settlement). On August 18, 2016, as agreed to by the Parties, the Settlement was filed with FERC concurrent with a motion for interim rates to be placed into effect on September 1, 2016. On August 26, 2016, the Chief Administrative Law Judge issued an order approving the interim rates effective September 1, 2016.

On October 20, 2016, the FERC issued an order approving the Settlement reached between the Partnership and the other parties. Pursuant to the Settlement, there will be a rate moratorium wherein no new firm recourse rates can be placed into effect on the Partnership's mainline or Eastchester facilities until September 1, 2020. Following the conclusion of the moratorium, if no rate case is filed or if no new rate settlement is reached, the Partnership must file a Section 4 rate case no later than September 1, 2022. During the period of the moratorium, Iroquois will reduce its 100% load factor interzone rate by approximately $0.075 per dekatherm (approximately $0.02 beginning September 1, 2016, an additional $0.02 beginning September 1, 2017, and an additional $0.035 beginning September 1, 2018). Also during the moratorium period, Iroquois will reduce its 100% load factor Eastchester rate by approximately $0.24 per dekatherm (approximately $0.18 beginning September 1, 2016, and an additional $0.06 beginning September 1, 2018).

Based on long-term firm service contracts in place on September 1, 2016, the approved settlement has resulted in reductions in long-term firm revenue of $2.5 million in 2016, $6.4 million in 2017, and $6.6 million in 2018. It is also expected to result in reductions in long-term firm revenue of approximately $9.3 million in 2019. The settlement also required a modification to the Partnership's depreciation rates which is described in Natural Gas Plant in service in Note 2.

Income Tax

In December 2016, FERC issued 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 had been 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 (MLP) receiving a tax allowance and a return on equity (ROE) derived from the discounted cash flow (DCF) methodology did not result in double recovery of taxes.

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 including a reduction of the federal corporate income tax rate. Under the 2017 Tax Act, the Partnership continues to be a non-taxable limited partnership for federal income tax purposes and federal 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 with respect to federal income taxes as a result of the 2017 Tax Act.

On March 15, 2018, FERC issued the following: (1) the Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) to address the treatment of income taxes for ratemaking purposes for MLPs, (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact that the NOPR federal income tax rate reduction and the Revised Policy Statement could have on a pipeline's ROE assuming a single-issue adjustment to a pipeline's rates, and (3) an Notice of Inquiry (NOI) seeking comment on how FERC should address changes related to accumulated deferred income taxes (ADIT) and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement (Order on Rehearing) dismissing rehearing requests related to the Revised Policy Statement and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR. On November 15, 2018, FERC issued a policy statement on the Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset (Excess ADIT Policy Statement) addressing certain issues raised in the NOI issued last March 15, 2018 (collectively, the "2018 FERC Actions"). Each of the 2018 FERC Actions is further described below.

FERC Revised Policy Statement on Income Tax Allowance Cost Recovery in MLP Pipeline Rates

The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance regarding ADIT for MLP pipelines and other pass through entities. FERC found that to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as the refund or collection of excess or deficient deferred income tax assets or liabilities.

NOI Regarding the Effect of the 2017 Tax Act on Commission-Jurisdictional Rates

In the NOI, FERC sought comments to determine what additional action as a result of the 2017 Tax Act, if any, was required by FERC related to the ADIT that were reserved in anticipation of being paid to the IRS, but which no longer accurately reflected the future income tax liability. The NOI also sought comments on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of the 2017 Tax Act on regulated rates or earnings.

As noted above, FERC's Order on Rehearing provided guidance regarding ADIT for MLP pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its cost-of-service rates.

As noted above, on November 15, 2018, FERC issued the Excess ADIT Policy Statement addressing certain (but not all) issues raised in this NOI. The Excess ADIT Policy Statement clarified the FERC accounts in which pipelines should record amortization of excess and/or deficient ADIT for accounting and ratemaking purposes.

The Excess ADIT Policy Statement also addressed how to disclose reversals of ADIT account balances in FERC's annual financial report filings. The policy statement also stated that for pipelines that continue to have an income tax allowance, excess/deficient ADIT associated with an asset that is sold or retired after December 31, 2017 must continue to be amortized in rates even after the sale or retirement of the asset.

Final Rule on Tax Law Changes for Interstate Natural Gas Companies

On July 19, 2018, FERC issued a Final Rule to address the treatment of income taxes for ratemaking purposes. The Final Rule established a schedule by which interstate pipelines must have either (i) filed a new uncontested rates settlement or (ii) filed a one-time report, called FERC Form No. 501-G that quantified the rate impact of the 2017 Tax Act on FERC regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. In addition to filing the one-time report, each pipeline had four options: (1) Each pipeline may simultaneously make a limited section 4 filing to reduce its rates by the percentage reduction in its cost of service shown in its FERC Form No. 501-G; (2) Each pipeline may simultaneously commit to file either a prepackaged uncontested rate settlement or a general NGA section 4 rate case if it believes that using the limited section 4 option will not result in a just and reasonable rate. If the pipeline commits to file either by December 31, 2018, FERC will not initiate a section 5 investigation of its rates prior to that date; (3) Alternatively, each pipeline that does not believe it has to change its rates may choose to file a statement explaining why; (4) Finally, a pipeline may file the one-time report without taking any other action. At that point, FERC would consider whether to initiate a section 5 investigation of any pipeline that has not submitted a limited section 4 rate reduction filing or committed to file a general section 4 rate case.

Iroquois filed its FERC Form No. 501-G on December 6, 2018 under option 3 explaining that no changes are warranted to its rates primarily because of the approved settlement rate moratorium in Docket RP16-301 and approved by the FERC on October 20, 2016. On January 8, 2019, Iroquois convened a settlement conference, at which the parties reached a settlement in principle to resolve any potentially outstanding issues relating to FERC's Final Rule relating to the treatment of income taxes for ratemaking purposes. Under the settlement in principle, Iroquois will reduce its tariff rates to reflect the impacts of the federal income tax changes as shown on Iroquois' Form No. 501-G. Iroquois anticipates that the settlement will be uncontested.

Brookfield, Connecticut Site Clean Up

On June 27, 2003, the Partnership purchased real property in Brookfield, Connecticut upon which it constructed its Brookfield compressor station (Brookfield Site or Site). On November 3, 2004, the Connecticut Department of Energy and Environmental Protection (DEEP) approved the Site's remediation plan and scope of work schedule. After the major clean-up, re-grading, and seeding work at the Brookfield Site was completed (with the exception of buried tires on the property which is discussed below), Iroquois received a Letter of No Audit (LNA) from the DEEP dated November 13, 2014. The LNA states that the DEEP agrees with Iroquois' Licensed Environmental Professional (LEP) that the site is now clean (with the exception of the buried tires on the property) and closes the Environmental Condition Assessment Form (ECAF) for the Brookfield Voluntary Cleanup. For the remaining buried tires on the Brookfield site, Iroquois has entered into the state Stewardship Program. The stewardship program authorization expires in May of 2022 at which time Iroquois will file for an additional 10-year extension. The program requires monitoring of the tire area until 2041 and remediation of any erosion, subsidence, or tires that have worked their way to the surface. It is not anticipated that the ongoing monitoring of this site will have a material adverse effect on the Partnership's financial condition or results of operations.

Wright Interconnect Project

In December of 2012, the Partnership entered into a Precedent Agreement (PA) with Constitution Pipeline Company, LLC (Constitution). The PA requires the Partnership to expand its current compression station located in Wright, New York. The project, which consists of constructing two new compressor units in addition to new metering facilities, and other minor facility modifications, would enable the Partnership to accept up to 650,000 Dth/d of gas from the proposed Constitution pipeline and deliver this gas into either the Partnership's currently existing mainline or into the Tennessee Gas Pipeline. Pursuant to the PA, Constitution and the Partnership will enter into a capacity lease agreement in which Constitution leases the transmission capacity made available by the new compressor units. This lease agreement is for a period of fifteen years with an option for Constitution to extend the lease an additional five years. This project will require FERC and other regulatory approvals. On June 13, 2013, the Partnership and Constitution filed for FERC approval of the project. On December 2, 2014, the Partnership received its 7(c) Certificate Order from FERC granting approval for the project (as well as Constitutions' pipeline project), with the approval conditioned on the Partnership obtaining all outstanding permits. The Partnership continues to work with State and Local authorities to obtain all required permits. On November 5, 2018, FERC granted a 2-year extension to complete construction of the project to the Partnership and Constitution.

On April 22, 2016, the New York State Department of Environmental Conservation (DEC) denied Constitution's application for a water quality certification (WQC) under Section 401 of the Clean Water Act. Constitution had applied for the 401 WQC in order to construct its 124 mile pipeline. On May 16, 2016, Constitution filed a petition for review of the denial to the U. S. Court of Appeals for the Second Circuit (Second Circuit), arguing that the DEC's denial was arbitrary and capricious. On August 18, 2017, the Second Circuit issued its opinion denying in part and dismissing in part Constitution's petition. The Second Circuit declined to rule on Constitution's argument that DEC's long-delayed decision on Constitution's Section 401 application triggered a waiver of the DEC's WQC authority under Section 401. The Second Circuit determined that it lacked jurisdiction to address that issue, as jurisdiction lay exclusively with the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) under the Natural Gas Act (NGA). On Constitution's merit arguments, the Second Circuit upheld the DEC's denial of the WQC. Constitution's petition for rehearing of the Second Circuit's decision, and its petition for a writ of certiorari to the U.S. Supreme Court, were both denied. On October 11, 2017, Constitution petitioned the FERC for a declaratory order finding that the DEC failed to act within the statutorily prescribed period of time on Constitution's WQC Application and that such failure to act constitutes a waiver of the DEC's Section 401 authority. FERC issued an Order on January 11, 2018, denying Constitution's petition, and denied rehearing of that order on July 19, 2018. Constitution has petitioned the D.C. Circuit for review of the two orders issued by FERC. The matter is pending.

The Partnership is required to obtain a Title V Facility Permit (Permit), under the Clean Air Act, for the construction and operations of the WIP facilities. On July 26, 2013, the Partnership filed a Permit application with the DEC, and the DEC subsequently published a Notice of Complete Application (NOCA) on December 24, 2014. The DEC and the Environmental Protection Agency (EPA) regulations implementing the Clean Air Act, state that final action on a Title V Permit must be taken within eighteen months of publishing the NOCA. However, the DEC failed to submit the Permit to the Environmental Protection Agency on or before June 24, 2016, thus violating the eighteen month requirement of the Clean Air Act. The Partnership filed a petition with the DC Circuit on July 13, 2016, pursuant to the NGA, regarding the DEC's failure to timely submit the Permit to the EPA. On October 6, 2016, as amended February 15, 2018, the Partnership and the DEC entered into and filed a Stipulation of Settlement and a Joint Motion to Hold Petition in Abeyance Pending Performance of Stipulation of Settlement. Among other provisions, the Stipulation requires the DEC to submit the Permit to the EPA in the event that Constitution prevails in its litigation regarding the DEC WQC, or is otherwise able to resolve the matter and obtain authority from FERC to commence construction. It is anticipated that, once the Permit is submitted to the EPA, final action on the Permit will be taken.

As of December 31, 2018 the Partnership has incurred approximately $48.6 million of expenditures primarily related to engineering and procurement of materials and has made approximately $2.4 million in additional project related commitments. An unfavorable resolution on the WIP Project could result in the impairment of a significant portion of these construction work in progress costs. However, due to contractual agreements in place, including a guarantee from Williams Partners, L.P., a 41% owner of Constitution, the Partnership does not believe it is at financial risk for these expenditures.

Litigation Proceedings

The Partnership is a party to various legal matters incidental to its business. However, the Partnership believes that the outcome to these proceedings will not have a material adverse effect on the Partnership's financial condition or results of operations.

No liabilities have been recorded by the Partnership in conjunction with any legal matters.

Commitments

The Partnership leases its office space under operating lease arrangements. The leases expire at various dates through 2022 and are renewable at the Partnership's option. The Partnership also has a right-of-way commitment on Long Island, NY, which requires annual payments escalating 5% per year over the 39-year term of the agreement, which expires in 2030. In addition, the Partnership leases various equipment under non-cancelable operating leases.

During the years ended December 31, 2018, 2017, and 2016, the Partnership made payments of $1.2 million per year under these arrangements, which were recorded as rental expense. Future minimum payments are as follows (millions of dollars).

Year	**Amount**
2019	$1.1
2020	$1.2
2021	$0.6
2022	$0.3
2023	$0.2
Thereafter	$2.2

Distributions

The Partnership adopted a distribution resolution to distribute surplus cash to its partners of $57.4 million to be paid as part of its quarterly distributions over 11 quarters. Under the terms of the resolution an additional $5.2 million will be paid per quarter, which began with the second quarter 2017 distributions. As of December 31, 2018 the Partnership made six surplus cash distributions, in accordance with the resolution, totaling $31.4 million.

NOTE 8 AFFILIATED PARTY TRANSACTIONS:

The following table summarizes the Partnership's affiliated party transactions (thousands of dollars):

2018	Payments to Affiliated Parties	Due to Related Parties	Due from Affiliated Parties	Revenue from Affiliated Parties	Equity Distributions to Affiliated Parties
TC PipeLines Intermediate Limited Partnership	$–	$–	$–	$–	$56,370
Iroquois GP Holding Company, LLC	–	–	–	–	29,625
Dominion Iroquois, Inc.	184	–	–	–	27,499
TransCanada Iroquois Ltd.	–	–	–	–	754
Totals	$184	$–	$–	$–	$114,248

2017	Payments to Affiliated Parties	Due to Related Parties	Due from Affiliated Parties	Revenue from Affiliated Parties	Equity Distributions to Affiliated Parties
TC PipeLines Intermediate Limited Partnership	$–	$–	$–	$–	$27,372
Iroquois GP Holding Company, LLC	–	–	–	–	26,054
Dominion Iroquois, Inc.	–	–	–	–	24,136
TransCanada Iroquois Ltd.	–	–	–	–	13,416
TCPL Northeast, Ltd.	–	–	–	–	9,498
Totals	$–	$–	$–	$–	$100,476

2016	Payments to Affiliated Parties	Due to Related Parties	Due from Affiliated Parties	Revenue from Affiliated Parties	Equity Distributions to Affiliated Parties
TransCanada PipeLines	$1	$–	$–	$5	$42,419
Dominion Resources	–	–	–	–	22,052
Avangrid*	6	–	–	2,647	2,192
Dominion Midstream	–	–	–	–	23,337
Totals	$7	$–	$–	$2,652	$90,000

* Affiliated party through March 31, 2016.

Revenues from affiliated parties were primarily for gas transportation services. Payments to affiliated parties in 2018 primarily consisted of an interconnect project settlement. Payments to affiliated parties in 2016 primarily consisted of a refund due to transportation capacity release, and utility bills.

NOTE 9 MAJOR CUSTOMERS:

For the years ended December 31, 2018, December 31, 2017 and December 31, 2016, two customers provided significant operating revenues totaling $49.1 million, $46.7 million, and $46.9 million, respectively.

NOTE 10 REVENUES:

On January 1, 2018, the Partnership adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. The reported results for all periods in 2018 reflect the application of the new guidance, while the reported results for all periods in 2017 and 2016 were prepared under previous revenue recognition guidance which is referred to herein as legacy U.S. GAAP.

Disaggregation of Revenues

For the year ended December 31, 2018, virtually all the Partnership's revenues were from capacity arrangements and transportation contracts with customers as discussed under Note 2-Significant Accounting Policies.

Also noted under Note 2 – Significant Accounting Policies, a portion of the Partnership's revenues collected may be subject to refund when a rate proceeding is ongoing or as part of a rate case settlement with customers. The Partnership uses its best estimate based on the facts and circumstances of the proceeding to provide for allowances for these potential refunds in the revenue we recognized.

During the year ended December 31, 2017 and 2018, the Partnership operated under a FERC approved 2016 rate settlement.

Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Partnership adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Partnership is not required to analyze completed contracts at the date of adoption. The adoption of the new guidance did not have a material impact on the Partnership's previously reported financial statements at December 31, 2017.

Pro-forma Financial Statements under Legacy U.S. GAAP

At December 31, 2018, had legacy U.S. GAAP been applied, there would be no change in the Partnership's reported consolidated balance sheet and consolidated statements of comprehensive income line items.

Contract Balances

The Partnership's contract balances consist primarily of receivables from contracts with customers reported under accounts receivable-trade on the consolidated balance sheet. Additionally, the accounts receivable represents the Partnership's unconditional right to recognize revenue for services completed which includes billed and unbilled accounts.

Future Revenue from Remaining Performance Obligations

In the application of the right to invoice practical expedient, the Partnership's revenues from regulated capacity arrangements are recognized based on rates specified in the contract. Therefore, the amount invoiced, which includes the variable volume of natural gas transported, corresponds directly to the value the customer received. These revenues are recognized monthly once the Partnership's performance obligation to provide capacity has been satisfied. The Partnership has also utilized the associated practical expedient that does not require disclosure of information related to its remaining performance obligations.

NOTE 11 OTHER COMPREHENSIVE LOSS:

For the years ended December 31, 2018, December 31, 2017, and December 31, 2016, the accumulated balances related to other comprehensive loss consisted of the following (thousands of dollars):

	Adjustment to Retirement Benefit Plans	Unrealized Gain on Excess Benefit Plan Investments	Accumulated Other Comprehensive (Loss)/Income
Balance as of 12/31/17	$(1,517)	$131	$(1,386)
Current-period other comprehensive (loss)	(2,458)	(63)	(2,521)
Balance as of 12/31/18	$(3,974)	$68	$(3,907)

	Adjustment to Retirement Benefit Plans	Unrealized Gain on Excess Benefit Plan Investments	Accumulated Other Comprehensive (Loss)/Income
Balance as of 12/31/16	$(3,264)	$48	$(3,216)
Current-period other comprehensive income	1,747	83	1,830
Balance as of 12/31/17	$(1,517)	$131	$(1,386)

	Adjustment to Retirement Benefit Plans	Unrealized Gain/ (Loss) on Excess Benefit Plan Investments	Accumulated Other Comprehensive Loss
Balance as of 12/31/15	$(3,185)	$7	$(3,178)
Current-period other comprehensive (loss)/income	(79)	41	(38)
Balance as of 12/31/16	$(3,264)	$48	$(3,216)

NOTE 12 RETIREMENT BENEFIT PLANS:

The Partnership has established a noncontributory cash balance retirement plan (the Plan) covering substantially all employees. Pension benefits are based on years of credited service and employees' career earnings, as defined in the Plan. The Partnership's funding policy is to contribute, annually, an amount at least equal to that which will satisfy the minimum funding requirements of the Employee Retirement Income Security Act (ERISA) plus such additional amounts, if any, as the Partnership may determine to be appropriate from time to time.

The Partnership also has adopted an excess benefit plan (EBP) that provides retirement benefits to executive officers. The EBP recognizes total compensation and service that would otherwise be disregarded due to Internal Revenue Code limitations on compensation in determining benefits under the regular retirement plan. The EBP is not considered to be funded for ERISA purposes and benefits are paid when due from general corporate assets. A Rabbi Trust, which is included in other assets and deferred charges on the Partnership's consolidated balance sheets, has been established to partially cover this obligation. The Rabbi Trust is an irrevocable trust which can be used to satisfy creditors.

The consolidated net cost for pension benefit plans included in the consolidated statements of comprehensive income for the years ending December 31 (which is the measurement date for each year), includes the following components (thousands of dollars):

	2018	2017	2016
Service cost	**$1,544**	$1,553	$1,550
Interest cost	**843**	885	744
Expected return on plan assets	**(1,749)**	(1,680)	(1,562)
Recognition of net actuarial loss	**187**	201	222
Net periodic benefit cost	**$825**	$959	$954

In the consolidated statements of operations, service cost is included in operation and maintenance expenses and the other components of net periodic benefit cost are included in other, net.

The following tables represent the Plans' combined funded status reconciled to amounts included in the consolidated balance sheets as of December 31, 2018 and 2017 (thousands of dollars):

	2018	2017
Change in benefit obligation		
Benefit obligation at beginning of year	**$24,814**	$22,792
Service cost	**1,544**	1,553
Interest cost	**843**	885
Actuarial (gain)/loss	**(1,043)**	432
Benefits Paid	**(1,412)**	(848)
Benefit obligation at end of year	**$24,746**	$24,814
Change in plan assets		
Fair value of plan assets at beginning of year	**$28,549**	$24,418
Actual return on plan assets	**(1,939)**	3,658
Employer contribution	**1,221**	1,321
Benefits Paid	**(1,412)**	(848)
Fair value of plan assets at end of year	**$26,419**	$28,549
Funded Status	**$1,673**	$3,735
	2018	2017
Amount Recognized in Consolidated Balance Sheets Consisted of:		
Non-current asset	**$2,770**	$4,759
Current liability	**(50)**	(32)
Non-current liability	**(1,047)**	(992)
Net amount recognized	**$1,673**	$3,735

	Plan Assets			**Benefit Obligations**		
	2018	2017	2016	**2018**	2017	2016
Plans in overfunded status	**$26,419**	$28,549	$24,418	**$23,649**	$23,790	$21,898
Plans in underfunded status	**–**	–	–	**1,097**	1,024	894

The accumulated benefit obligation for the Partnership's retirement benefit plans was $24.7 million, $24.8 million and $22.8 million at December 31, 2018, 2017 and 2016, respectively.

Amounts recognized in accumulated other comprehensive income at December 31 (thousands of dollars):

	2018	2017	2016
Transition obligation	**–**	–	–
Prior service cost	**–**	–	–
Net loss	**$3,974**	$1,517	$3,264
Total Recognized in Accumulated Other Comprehensive Income	**$3,974**	$1,517	$3,264

Estimated net periodic benefit cost amortizations for the periods January 1 – December 31 (thousands of dollars):

	2019
Amortization of transition obligation	–
Amortization of prior service cost	–
Amortization of net loss	$158
Total Estimated Net Periodic Benefit Cost Amortizations	$158

The following table summarizes the weighted average assumptions used to determine benefit obligations as of December 31 (rates shown are rates at end of measurement period):

	Cash Balance Retirement Plan			**Excess Benefit Plans**		
	2018	2017	2016	**2018**	2017	2016
Discount rate	**4.15%**	3.50%	4.00%	**4.05%**	3.45%	3.85%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%

The following table summarizes the weighted average assumptions used to determine the net periodic benefit cost for years ended December 31 (rates shown are rates at beginning of measurement period):

	Cash Balance Retirement Plan			Excess Benefit Plans		
	2018	2017	2016	**2018**	2017	2016
Discount rate	**3.50%**	4.00%	3.70%	**3.45%**	3.85%	3.70%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%
Expected long-term return on plan assets	**7.00%**	7.00%	7.25%			

The expected long-term rate of return assumption was developed using a variety of factors including long-term historical return information, the current level of expected returns and general industry expectations. Adjustments are made to the expected long-term rate of return assumption when deemed necessary based upon revised expectations of future investment performance of the overall capital markets. The building block methodology was used to generate the capital market assumptions, to the extent that the expected return has not shifted the long term expected rate will not be adjusted.

The discount rate was selected to reflect the rates of return currently available on high quality fixed income securities whose cash flows match the timing and amount of future benefit payments of the plan. In particular, the discount rate takes into consideration the population of our pension plan and the anticipated payment stream as compared to the Citigroup Discount Yield Curve Index.

The following table summarizes the expected future benefit payments over the next five years and aggregate five years thereafter (thousands of dollars):

Year	**Benefit Payment**
2019	$655
2020	$1,147
2021	$1,634
2022	$1,743
2023	$1,428
2024-2028	$10,598

Plan Assets

The following table sets forth the Partnership's pension plans weighted average asset allocations and target asset allocations, and fair value of the plan assets at December 31, 2018 and December 31, 2017.

	Weighted Average Asset Allocation		Plan Target Asset Allocation		Fair Value of Plan Assets (thousands of dollars)	
	2018	2017	**2018**	2017	**2018**	2017
Mutual Funds						
U.S. Equities	**36%**	35%	**35%**	35%	**$9,457**	$9,919
International Equities	**22%**	18%	**22%**	18%	**5,787**	5,174
Real Estate	**3%**	3%	**3%**	3%	**931**	851
U.S. Fixed Income	**36%**	41%	**37%**	41%	**9,479**	11,751
Other	**3%**	3%	**3%**	3%	**765**	854
				Total	**$26,419**	$28,549

The Partnership's investment goal is to obtain a competitive risk adjusted return on the pension plan assets commensurate with prudent investment practices and the plan's responsibility to provide retirement benefits for its participants, retirees and their beneficiaries. The Plan's asset allocation targets are strategic and long term in nature and are designed to take advantage of the risk reducing impacts of asset class diversification.

Plan assets are periodically rebalanced to their asset class targets to reduce risk and to retain the portfolio's strategic risk/return profile. Investments within each asset category are further diversified with regard to investment style and concentration of holdings.

The Plan's investments are diversified to minimize the risk of a large loss. The Plan is constructed and maintained to provide prudent diversification among the asset classes in accordance with the asset allocation objectives. Within each asset class, there is prudent diversification with regard to investment styles and concentration of holdings.

Under the plans investment guidelines the portfolio may contain mutual funds which are managed in accordance with the diversification and industry concentration restrictions set forth in the Investment Company Act of 1940, as amended (the 1940 Act). Pursuant to the provisions of the 1940 Act, a mutual fund may not, with respect to 75% of its assets, (i) purchase securities of any issuer (except securities issued or guaranteed by the United States Government, its agencies or instrumentalities) if, as a result, more than 5% of its total assets would be invested in the securities of such issuer; or (ii) acquire more than 10% of the outstanding voting securities of any one issuer.

In addition, no mutual fund may purchase any securities which would cause more than 25% of its total assets to be invested in the securities of one or more issuers conducting their principal business activities in the same industry, provided that this limitation does not apply to investments in securities issued or guaranteed by the United States Government, its agencies or instrumentalities.

All but one of the assets within Iroquois' Pension Plan are valued using Level 1 inputs in accordance with GAAP. Level 1 inputs are defined as the quoted market process for identical assets on an active market to which an entity has access at the measurement date. As of December 31, 2018, one of the Plan's assets totaling $0.9 million is valued using Level 2 inputs, and the Partnership has the ability to redeem the asset or liability in the near term subsequent to the measurement date. Level 2 inputs are defined as inputs from other than quoted market prices that are observable for the asset or liability, either directly or indirectly (i.e. quoted market prices for similar assets or liabilities).

Contributions

Iroquois expects to contribute approximately $1.2 million to its pension plan in 2019.

GLOSSARY OF TERMS

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

2013 Term Loan Facility	TC PipeLines, LP's term loan credit facility under a term loan agreement as amended on September 29, 2017
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	Public Law No. 115-97, commonly known as the Tax Cuts and Jobs Act, enacted on December 22, 2017
2018 FERC Actions	FERC's March 15, 2018 issuance of (1) a revised Policy Statement to address the treatment of income taxes for rate-making purposes for master limited partnerships (MLPs), (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact of the U.S. federal income tax rate reduction and the revised Policy Statement could have on pipelines' revenue requirements, and (3) a Notice of Inquiry (NOI) seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation; FERC's July 18, 2018 issuance of (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing related to the revised Policy Statement and (2) a Final Rule adopting procedures from, and clarifying aspects of, the NOPR; and FERC's November 15, 2018, issuance of Accounting and Rate-making Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset and policy statement (Excess ADIT Policy Statement) addressing certain issues raised in the NOI issued on March 15, 2018
2018 GTN Settlement	Stipulation and Agreement of Settlement for GTN regarding its rates and terms and conditions of service approved by FERC on November 30, 2018
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
Class B Distribution	Annual distribution to TransCanada 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

Class B Reduction	Approximately 35 percent reduction applied to the estimated annual Class B Distribution beginning in 2018, which is equivalent to the percentage by which distributions payable to the common units were reduced in 2018. The Class B Reduction will continue to apply for any particular calendar year until distributions payable in respect of common units for such calendar year equal or exceed $3.94 per common unit
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
ILPs	Intermediate Limited Partnerships
IRS	Internal Revenue Service
Iroquois	Iroquois Gas Transmission System, L.P.
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
MLPs	Master limited partnerships
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	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership
Partnership ILPs	TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership

PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
PXP	Portland XPress Project of PNGTS to re-contract certain system capacity set to expire in 2019 as well as construct incremental compression facilities within PNGTS' existing footprint in Maine
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 XPress Project does not proceed.
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin
Westbrook XPress	Westbrook XPress Project of PNGTS that is part of a coordinated offering to transport incremental Western Canadian Sedimentary Basin natural gas supplies to the Northeast U.S. and Atlantic Canada markets through additional compression capability at an existing PNGTS facility
VIEs	Variable Interest Entities
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).

Corporate Information

Board of Directors [1]

Stanley G. Chapman, III
Chairman, TC PipeLines GP, Inc.
Executive Vice-President and President
U.S. Natural Gas Pipelines
TransCanada Corporation
Calgary, Alberta

Nathaniel A. Brown
President and Director
TC PipeLines GP, Inc.
Vice-President, U.S. Natural Gas Pipelines
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TransCanada PipeLines Limited
Houston, Texas

Jack F. Stark [2] [3] [4]
Former Chief Financial Officer
Imergy Power Systems
Fremont, California

Malyn K. Malquist [5] [6]
Retired Executive Vice-President and
Chief Financial Officer
Avista Corporation
Spokane, Washington

Walentin (Val) Mirosh [4] [6]
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Nadine E. Berge
Director, Corporate Compliance and
Legal Services
TransCanada PipeLines Limited
Calgary, Alberta

Sean M. Brett
Senior Vice-President, Energy
TransCanada PipeLines Limited
Calgary, Alberta

(1) Board of Directors of TC PipeLines GP, Inc.,
the General Partner of TC PipeLines, LP
(2) Lead Director
(3) Chair, Conflicts Committee
(4) Member, Audit Committee
(5) Chair, Audit Committee
(6) Member, Conflicts Committee

Officers [1]

Stanley G. Chapman, III
Chairman

Nathaniel A. Brown
President

Janine M. Watson
Vice-President and General Manager

William C. (Chuck) Morris
Vice-President, Principal Financial Officer and
Treasurer

Nancy F. Priemer
Vice-President, Taxation

Jon A. Dobson
Secretary

(1) Officers of TC PipeLines GP, Inc.,
the General Partner of TC PipeLines, LP

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