

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

**FORM 10-Q**

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

For the quarterly period ended June 30, 2018

or

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number: 001-35358

**TC PipeLines, LP**

(Exact name of registrant as specified in its charter)

**Delaware**

(State or other jurisdiction of  
incorporation or organization)

**52-2135448**

(I.R.S. Employer  
Identification Number)

**700 Louisiana Street, Suite 700  
Houston, Texas**

(Address of principle executive offices)

**77002-2761**

(Zip code)

**877-290-2772**

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes  No

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

Large accelerated filer

Non-accelerated filer

(Do not check if a smaller reporting company)

Accelerated filer

Smaller reporting company

Emerging growth company

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes  No

As of August 1, 2018, there were 71,306,396 of the registrant's common units outstanding.

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

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

2013 Term Loan Facility	TC PipeLines, LP's term loan credit facility under a term loan agreement as amended, dated September 29, 2017
2015 GTN Acquisition	Partnership's acquisition of the remaining 30 percent interest in GTN on April 1, 2015
2015 Term Loan Facility	TC PipeLines, LP's term loan credit facility under a term loan agreement as amended, dated September 29, 2017
2017 Acquisition	Partnership's acquisition of an additional 11.81 percent interest in PNGTS and 49.34 percent in Iroquois on June 1, 2017
2017 Great Lakes Settlement	Stipulation and Agreement of Settlement for Great Lakes regarding its rates and terms and conditions of service approved by FERC on February 22, 2018
2017 Northern Border Settlement	Stipulation and Agreement of Settlement for Northern Border regarding its rates and terms and conditions of service approved by FERC on February 23, 2018
2017 Tax Act	H.R.1, originally known as the Tax Cuts and Jobs Act, enacted on December 22, 2017
2018 FERC Actions	FERC's March 15, 2018 issuance of (1) a 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 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; and 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
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM program	At-the-market equity issuance program
Bison	Bison Pipeline LLC
Consolidated Subsidiaries	GTN, Bison, North Baja, Tuscarora and PNGTS
C2C Contracts	PNGTS' Continent-to-Coast Contracts with several shippers for a term of 15 years for approximately 82,000 Dth/day
DOT	U.S. Department of Transportation
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.
Great Lakes	Great Lakes Gas Transmission Limited Partnership
GTN	Gas Transmission Northwest LLC
IDRs	Incentive Distribution Rights
ILPs	Intermediate Limited Partnerships
Iroquois	Iroquois Gas Transmission System, L.P.
LIBOR	London Interbank Offered Rate
MLPs	Master limited partnerships
NGA	Natural Gas Act of 1938
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
Our pipeline systems	Our ownership interests in GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, PNGTS and Iroquois
Partnership	TC PipeLines, LP including its subsidiaries, as applicable
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership

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PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
PXP	Portland XPress Project
Term Loan Facilities	The 2013 Term Loan Facility and the 2015 Term Loan Facility, collectively
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
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
VIEs	Variable Interest Entities

Unless the context clearly indicates otherwise, TC PipeLines, LP and its subsidiaries are collectively referred to in this quarterly 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).

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**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,” “assume,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “forecast,” “should,” “predict,” “could,” “will,” “may,” and other terms and expressions of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking. These statements are based on management’s beliefs and assumptions and on currently available information and include, but are not limited to, statements regarding anticipated financial performance, future capital expenditures, liquidity, dropdown opportunities, market or competitive conditions, regulations, organic or strategic growth opportunities, contract renewals and ability to market open capacity, business prospects, outcome of regulatory proceedings and cash distributions to unitholders.

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

- the ability of our pipeline systems to sell available capacity on favorable terms and renew expiring contracts which are affected by, among other factors:
  - demand for natural gas;
  - changes in relative cost structures and production levels of natural gas producing basins;
  - natural gas prices and regional differences;
  - weather conditions;
  - availability and location of natural gas supplies in Canada and the United States (U.S.) in relation to our pipeline systems;
  - competition from other pipeline systems;
  - natural gas storage levels; and
  - rates and terms of service;
- the performance by the shippers of their contractual obligations on our pipeline systems;
- the outcome and frequency of rate proceedings or settlement negotiations on our pipeline systems;
- the impact of the 2017 Tax Act and the 2018 FERC Actions on our future operating performance;
- other potential changes in taxation of master limited partnerships (MLPs) by state or federal governments;
- increases in operational or compliance costs resulting from changes in laws and governmental regulations affecting our pipeline systems, particularly regulations issued by the Federal Energy Regulatory Commission (FERC), the U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT);
- the impact of 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, terms and closure of future potential acquisitions;
- potential conflicts of interest between TC PipeLines GP, Inc., our general partner (General Partner), TransCanada Corporation (TransCanada) and us;
- the impact of any impairment charges;
- the ability to maintain secure operation of our information technology including management of cybersecurity threats, acts of terrorism and related distractions;
- the expected impact of future accounting changes, commitments and contingent liabilities (if any);
- operating hazards, casualty losses and other matters beyond our control;
- the level of our indebtedness, including the indebtedness of our pipeline systems, and the availability of capital;
- unfavorable conditions in capital and credit markets, inflation and fluctuations in interest rates; and
- the overall increase in the allocated management and operational expenses on our pipeline systems for functions performed by TransCanada.

These are not the only factors that could cause actual results to differ materially from those expressed or implied in any forward-looking statement. Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. These and other risks are described in greater detail in Part II, Item 1A “Risk Factors” of this report and in Part I, Item 1A. “Risk Factors” of our Annual Report on Form 10-K for the year ended December 31, 2017 as filed with the SEC on February 26, 2018. All forward-looking

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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.

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**PART I — FINANCIAL INFORMATION**

**Item 1. Financial Statements**

**TC PIPELINES, LP**

**CONSOLIDATED STATEMENTS OF INCOME**

(unaudited) (millions of dollars, except per common unit amounts)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Transmission revenues	111	101	226	213
Equity earnings (Note 5)	36	24	95	60
Operation and maintenance expenses	(17)	(17)	(33)	(31)
Property taxes	(7)	(7)	(14)	(14)
General and administrative	(1)	(2)	(2)	(4)
Depreciation	(24)	(25)	(48)	(49)
Financial charges and other (Note 15)	(23)	(19)	(46)	(36)
<b>Net income before taxes</b>	<b>75</b>	<b>55</b>	<b>178</b>	<b>139</b>
Income taxes (Note 18)	—	—	(1)	(1)
<b>Net income</b>	<b>75</b>	<b>55</b>	<b>177</b>	<b>138</b>
Net income attributable to non-controlling interests	2	—	8	6
<b>Net income attributable to controlling interests</b>	<b>73</b>	<b>55</b>	<b>169</b>	<b>132</b>
<b>Net income attributable to controlling interest allocation (Note 9)</b>				
Common units	72	50	166	122
General Partner	1	5	3	8
TransCanada and its subsidiaries	—	—	—	2
	<b>73</b>	<b>55</b>	<b>169</b>	<b>132</b>
<b>Net income per common unit (Note 9) – basic and diluted</b>	<b>\$ 1.00</b>	<b>\$ 0.73</b>	<b>\$ 2.33</b>	<b>\$ 1.78</b>
<b>Weighted average common units outstanding – basic and diluted (millions)</b>	<b>71.3</b>	<b>68.9</b>	<b>71.2</b>	<b>68.6</b>
<b>Common units outstanding, end of period (millions)</b>	<b>71.3</b>	<b>69.0</b>	<b>71.3</b>	<b>69.0</b>

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

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**TC PIPELINES, LP CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Net income	75	55	177	138
Other comprehensive income				
Change in fair value of cash flow hedges (Note 13)	(1)	—	6	1
Amortization of realized loss on derivative financial instruments (Note 13)	2	1	2	1
Reclassification to net income of gains and losses on cash flow hedges (Note 13)	3	(1)	3	(1)
<b>Comprehensive income</b>	<b>79</b>	<b>55</b>	<b>188</b>	<b>139</b>

Comprehensive income attributable to non-controlling interests	3	—	9	6
<b>Comprehensive income attributable to controlling interests</b>	<b>76</b>	<b>55</b>	<b>179</b>	<b>133</b>

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

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**TC PIPELINES, LP  
CONSOLIDATED BALANCE SHEETS**

(unaudited) (millions of dollars)	June 30, 2018	December 31, 2017
<b>ASSETS</b>		
Current Assets		
Cash and cash equivalents	51	33
Accounts receivable and other (Note 14)	40	42
Inventories	8	8
Other	9	7
	<u>108</u>	<u>90</u>
Equity investments (Note 5)	1,211	1,213
Plant, property and equipment (Net of \$1,229 accumulated depreciation; 2017 - \$1,181)	2,086	2,123
Goodwill	130	130
Other assets	11	3
	<u>3,546</u>	<u>3,559</u>
<b>LIABILITIES AND PARTNERS' EQUITY</b>		
Current Liabilities		
Accounts payable and accrued liabilities	27	31
Accounts payable to affiliates (Note 12)	6	5
Distribution payable	—	1
Accrued interest	12	12
Current portion of long-term debt (Note 7)	36	51
	<u>81</u>	<u>100</u>
Long-term debt, net (Note 7)	2,272	2,352
Deferred state income taxes (Note 18)	10	10
Other liabilities	28	29
	<u>2,391</u>	<u>2,491</u>
Partners' Equity		
Common units	912	824
Class B units (Note 8)	95	110
General partner	22	24
Accumulated other comprehensive income (AOCI)	15	5
Controlling interests	<u>1,044</u>	<u>963</u>
Non-controlling interests	<u>111</u>	<u>105</u>
	<u>1,155</u>	<u>1,068</u>
	<u>3,546</u>	<u>3,559</u>
Contingencies (Note 16)		
Variable Interest Entities (Note 17)		
Subsequent Events (Note 19)		

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

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**TC PIPELINES, LP  
CONSOLIDATED STATEMENT OF CASH FLOWS**

(unaudited) (millions of dollars)	Six months ended June 30,	
	2018	2017
<b>Cash Generated From Operations</b>		
Net income	177	138
Depreciation	48	49
Amortization of debt issue costs reported as interest expense	1	1

Amortization of realized loss on derivative instrument (Note 13)	2	1
Accrual for costs related to the 2017 Acquisition	—	1
Equity earnings from equity investments (Note 5)	(95)	(60)
Distributions received from operating activities of equity investments (Note 5)	96	68
Change in other long term liabilities	(1)	—
Change in operating working capital (Note 11)	(5)	7
	<u>223</u>	<u>205</u>
<b>Investing Activities</b>		
Investment in Great Lakes	(4)	(4)
Acquisition of a 49.34 percent in Iroquois and an additional 11.81 percent in PNGTS	—	(605)
Distribution received from Iroquois as return of investment (Note 5)	5	—
Capital expenditures	(9)	(16)
	<u>(8)</u>	<u>(625)</u>
<b>Financing Activities</b>		
Distributions paid (Note 10)	(123)	(135)
Distributions paid to Class B units (Note 8)	(15)	(22)
Distributions paid to non-controlling interests	(3)	(5)
Distributions paid to former parent of PNGTS	—	(1)
Common unit issuance, net (Note 8)	40	92
Long-term debt issued, net (Note 7)	130	607
Long-term debt repaid (Note 7)	(225)	(128)
Debt issuance costs	(1)	(1)
	<u>(197)</u>	<u>407</u>
<b>Decrease in cash and cash equivalents</b>	<b>18</b>	<b>(13)</b>
Cash and cash equivalents, beginning of period	33	64
<b>Cash and cash equivalents, end of period</b>	<b><u>51</u></b>	<b><u>51</u></b>

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

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

(unaudited)	Limited Partners				General Partner	Accumulated Other Comprehensive Income <sup>(a)</sup>	Non-Controlling Interest	Total Equity
	Common Units		Class B Units					
	millions of units	millions of dollars	millions of units	millions of dollars	millions of dollars	millions of dollars	millions of dollars	millions of dollars
Partners' Equity at December 31, 2017	70.6	824	1.9	110	24	5	105	1,068
Net income	—	166	—	—	3	—	8	177
Other comprehensive income	—	—	—	—	—	10	1	11
ATM equity issuances, net (Note 8)	0.7	39	—	—	1	—	—	40
Distributions	—	(117)	—	(15)	(6)	—	(3)	(141)
Partners' Equity at June 30, 2018	<u>71.3</u>	<u>912</u>	<u>1.9</u>	<u>95</u>	<u>22</u>	<u>15</u>	<u>111</u>	<u>1,155</u>

<sup>(a)</sup> Gains (Losses) related to cash flow hedges reported in Accumulated Other Comprehensive Income and expected to be reclassified to Net income in the next 12 months are estimated to be \$3 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.

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

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**TC PIPELINES, LP**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)**

**NOTE 1 ORGANIZATION**

TC PipeLines, LP and its subsidiaries are collectively referred to herein as the Partnership. The Partnership was formed by TransCanada PipeLines Limited, a wholly owned subsidiary of TransCanada Corporation (TransCanada Corporation together with its subsidiaries collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America.

The Partnership owns its pipeline assets through three intermediate limited partnerships (ILPs), TC GL Intermediate Limited Partnership, TC PipeLines Intermediate Limited Partnership and TC Tuscarora Intermediate Limited Partnership.

**NOTE 2 SIGNIFICANT ACCOUNTING POLICIES**

The accompanying financial statements and related notes have been prepared in accordance with United States generally accepted accounting principles (GAAP) and amounts are stated in U.S. dollars. The results of operations for the three and six months ended June 30, 2018 and 2017 are not necessarily indicative of the results that may be expected over the full fiscal year.

The accompanying financial statements should be read in conjunction with the audited financial statements and notes thereto for the year ended December 31, 2017 included in our Annual Report on Form 10-K. That report contains a more comprehensive summary of the Partnership's significant accounting policies. In the opinion of management, the accompanying financial statements contain all of the appropriate adjustments, all of which are normally recurring adjustments unless otherwise noted, and considered necessary to present fairly the financial position of the Partnership, the results of operations and cash flows for the respective periods. Our significant accounting policies are consistent with those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017, except as described in Note 3, Accounting Pronouncements.

### **Basis of Presentation**

The Partnership consolidates its interests in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. The Partnership uses the equity method of accounting for its investments in entities over which it is able to exercise significant influence.

Acquisitions by the Partnership from TransCanada are considered common control transactions. When businesses are acquired from TransCanada that will be consolidated by the Partnership, the historical financial statements are required to be recast, except net income 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.

### **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.

## **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

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

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

In January 2018, the FASB issued new guidance on accounting for land easements which provides an optional transition practical expedient to not evaluate existing or expired land easements not accounted for as leases prior to entity's adoption of the new 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 continues to monitor and analyze additional guidance and clarifications provided by the FASB.

The new guidance is effective on January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership has substantially completed an analysis and preliminary inventory listing of existing lease agreements, and continues to analyze contracts that may contain leases. The Partnership continues to evaluate the financial impact of the application of the new guidance on its consolidated financial statements. The Partnership has also selected a system solution and is in the testing stage of its implementation. The Partnership continues to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

### **Goodwill Impairment**

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

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### **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. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

### **NOTE 4 REGULATORY**

In December 2016, FERC issued a Notice of Inquiry (NOI) Regarding the Commission's Policy for Recovery of Income Tax Costs (Docket No. PL17-1-000) requesting initial comments regarding how to address any "double recovery" resulting from FERC's current income tax allowance and rate of return policies that 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 H.R.1, originally known as the Tax Cuts and Jobs Act (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. We are 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 (1) a 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 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 (collectively, the "2018 FERC Actions"). The Final Rule will become effective September 13, 2018, and is subject to requests for further rehearing and clarification. Each 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 Tax Law Changes for Interstate Natural Gas Companies***

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rates settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantifies the isolated rate impact of the



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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:

- 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;
- 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 either by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date;
- file a statement explaining its rationale for why it does not believe the pipeline's rates must change; and
- 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.

We continue to evaluate this Final Rule and our next course of action, however, we do not expect an immediate or a retroactive impact from the Final Rule or the Revised Policy Statement described above.

***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.

***Impairment Considerations***

As noted under Note 2, 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 at the date of the financial statements. Although we believe these estimates and assumptions are reasonable, actual results could differ.

We review property, plant and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstance indicate that it might be impaired. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, an impairment test is not performed.

Until the 2018 FERC Actions are implemented through individual rate proceedings or settlements, and we have fully evaluated our respective alternatives to minimize any negative impact on our future operating performance and cash flows, we believe that it is not more likely than not that the fair values of our reporting units are less than their respective carrying values. Therefore, a goodwill impairment test was not performed. Also, we have determined there is no indication that the carrying values of property, plant and equipment and equity investments potentially impacted by the 2018 FERC Actions are not recoverable.

We will continue to monitor developments and assess our goodwill for impairment. We will also review our property, plant and equipment and equity investments for recoverability as new information becomes available.

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At December 31, 2017, the estimated fair value of our investment in Great Lakes exceeded its carrying value by less than 10 percent. There is a risk that the 2018 FERC Actions, once implemented through the individual rate proceeding or settlement, could result in an impairment charge to our equity method goodwill on Great Lakes which amounted to \$260 million at June 30, 2018 (December 31, 2017 — \$260 million). Additionally, given that the estimated fair value of Tuscarora exceeded its carrying value by less than 10 percent in its most recent valuation, there is also a risk that the \$82 million goodwill at June 30, 2018 (December 31, 2017 - \$82 million) related to Tuscarora could be negatively impacted by the 2018 FERC Actions once implemented through the individual rate proceeding or settlement.

**NOTE 5 EQUITY INVESTMENTS**

The Partnership has equity interests in Northern Border, Great Lakes and 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 17).

(unaudited) (millions of dollars)	Interest at June 30, 2018	Three months ended June 30,		Six Months ended June 30,		June 30, 2018	December 31, 2017
		2018	2017	2018	2017		
Northern Border <sup>(a)</sup>	50%	15	15	32	34	505	512
Great Lakes	46.45%	12	6	36	23	485	479
Iroquois <sup>(b)</sup>	49.34%	9	3	27	3	221	222
		<u>36</u>	<u>24</u>	<u>95</u>	<u>60</u>	<u>1,211</u>	<u>1,213</u>

(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 interest in April 2006.

(b) Equity earnings from Iroquois is net of the 29-year amortization of a \$10 million purchase price discrepancy assumed by the Partnership from TransCanada at the time of the 2017 Acquisition.

### Distributions from Equity Investments

Distributions received from equity investments for the three and six months ended June 30, 2018 were \$56 million and \$101 million, respectively (2017 — \$40 million and \$68 million) of which \$2.6 million and \$5.2 million, respectively, (2017 - 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 did not have undistributed earnings from Northern Border for the three and six months ended June 30, 2018 and 2017.

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

(unaudited) (millions of dollars)	June 30, 2018	December 31, 2017
<b>ASSETS</b>		
Cash and cash equivalents	11	14
Other current assets	34	36
Plant, property and equipment, net	1,056	1,063
Other assets	14	14
	<u>1,115</u>	<u>1,127</u>
<b>LIABILITIES AND PARTNERS' EQUITY</b>		
Current liabilities	37	38
Deferred credits and other	33	31
Long-term debt, net <sup>(a)</sup>	264	264
Partners' capital	782	795
Accumulated other comprehensive loss	(1)	(1)
	<u>1,115</u>	<u>1,127</u>

(a) No current maturities as of June 30, 2018 and December 31, 2017.

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(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Transmission revenues	68	69	140	144
Operating expenses	(19)	(18)	(38)	(36)
Depreciation	(15)	(15)	(30)	(30)
Financial charges and other	(4)	(5)	(7)	(9)
<b>Net income</b>	<u>30</u>	<u>31</u>	<u>65</u>	<u>69</u>

### Great Lakes

The Partnership made an equity contribution to Great Lakes of \$4 million in the first quarter of 2018. This amount represents the Partnership's 46.45 percent share of a \$9 million cash call from Great Lakes to make a scheduled debt repayment.

The Partnership did not have undistributed earnings from Great Lakes for the three and six months ended June 30, 2018 and 2017.

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

(unaudited) (millions of dollars)	June 30, 2018	December 31, 2017
<b>ASSETS</b>		
Current assets	89	107

Plant, property and equipment, net	695	701
	<u>784</u>	<u>808</u>
<b>LIABILITIES AND PARTNERS' EQUITY</b>		
Current liabilities	49	75
Net long-term debt, including current maturities <sup>(a)</sup>	250	259
Other long term liabilities	—	1
Partners' equity	485	473
	<u>784</u>	<u>808</u>

<sup>(a)</sup> Includes current maturities of \$21 million as of June 30, 2018 (December 31, 2017 - \$19 million).

(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Transmission revenues	53	41	134	103
Operating expenses	(15)	(17)	(32)	(30)
Depreciation	(8)	(7)	(16)	(14)
Financial charges and other	(5)	(5)	(9)	(10)
<b>Net income</b>	<u>25</u>	<u>12</u>	<u>77</u>	<u>49</u>

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### Iroquois

On June 1, 2017, the Partnership, through its interest in TC PipeLines Intermediate Limited Partnership acquired a 49.34 percent interest in Iroquois. During the three and six months ended June 30, 2018, the Partnership received distributions from Iroquois amounting to \$14 million and \$28 million, respectively, which includes the Partnership's 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately \$2.6 million and \$5.2 million, respectively. The unrestricted cash does not represent a distribution of Iroquois' cash from operations during the period and therefore it was reported as distributions received as return of investment in the Partnership's consolidated statement of cash flows.

Iroquois declared its second quarter 2018 distribution of \$29 million on July 25, 2018, of which the Partnership received its 49.34 percent share of \$14 million on August 1, 2018. The distribution includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately \$2.6 million. The Partnership did not have undistributed earnings from Iroquois for the three and six months ended June 30, 2018 and 2017.

The summarized financial information provided to us by Iroquois for the period from the June 1, 2017 acquisition date through June 30, 2018 is as follows:

(unaudited) (millions of dollars)	June 30, 2018	December 31, 2017
<b>ASSETS</b>		
Cash and cash equivalents	100	86
Other current assets	26	36
Plant, property and equipment, net	584	591
Other assets	10	8
	<u>720</u>	<u>721</u>
<b>LIABILITIES AND PARTNERS' EQUITY</b>		
Current liabilities	17	17
Net long-term debt, including current maturities <sup>(a)</sup>	327	329
Other non-current liabilities	13	9
Partners' equity	363	366
	<u>720</u>	<u>721</u>

<sup>(a)</sup> Includes current maturities of \$145 million as of June 30, 2018 (December 31, 2017 - \$4 million).

(unaudited) (millions of dollars)	Three months ended June 30, 2018	One month ended June 30, 2017	Six months ended June 30, 2018	One month ended June 30, 2017
Transmission revenues	44	14	105	14
Operating expenses	(14)	(5)	(28)	(5)
Depreciation	(7)	(2)	(15)	(2)
Financial charges and other	(4)	(1)	(7)	(1)
<b>Net income</b>	<u>19</u>	<u>6</u>	<u>55</u>	<u>6</u>

### NOTE 6 REVENUES

In 2014, the FASB issued new guidance on revenue from contracts with customers. The Partnership adopted the new guidance on January 1, 2018 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

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## Disaggregation of Revenues

For the three and six months ended June 30, 2018, virtually all of the Partnership’s revenues were from capacity arrangements and transportation contracts with customers as discussed in more detail below.

### Capacity Arrangements and Transportation Contracts

The Partnership’s performance obligations in its contracts with customers consist primarily of capacity arrangements and natural gas transportation contracts.

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. The Partnership has elected to utilize the practical expedient of recognizing revenue as invoiced.

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. 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.

### 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 June 30, 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

<u>(unaudited-millions of dollars)</u>	<u>June 30, 2018</u>	<u>January 1, 2018</u>
Receivables from contracts with customers <sup>(a)</sup>	37	40
Contract assets <sup>(b)</sup>	—	—

<sup>(a)</sup> Recorded as Trade accounts receivable and reported as Accounts receivable and other in the consolidated balance sheet (Refer also to Note 14)

<sup>(b)</sup> Contract assets primarily relate to the Partnership’s right to recognize revenues for services completed but not invoiced at the reporting date. Any change in Contract assets is primarily related to the transfer to Accounts receivable when the right to recognize revenue becomes unconditional and the customer is invoiced as well as when revenue increases but remains to be invoiced. The Partnership did not have any Contract assets at January 1, 2018 and June 30, 2018.

### Future revenue from remaining performance obligations

As required by the new revenue recognition guidance, the Partnership is required to provide disclosure on future revenue allocated to remaining performance obligations on our contracts with customers that have not yet been recognized. However, all of the Partnership’s contracts qualify for the use of a practical expedient listed below and therefore no disclosure on future revenues from remaining performance obligations is necessary:

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- 1) The original expected duration of the contract is one year or less.
- 2) The Partnership recognizes revenue from the contract that is equal to the amount invoiced. This is referred to as the ‘right to invoice’ practical expedient.
- 3) The variable revenue generated from the contract is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation in a series. A single performance obligation in a series occurs when the promises under a contract are a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over time.

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 on a monthly basis once the Partnership’s performance obligation to provide capacity has been satisfied. In

addition, the Partnership considers interruptible transportation service revenues to be variable revenues as volumes cannot be estimated. These variable revenues are recognized on a monthly basis when the Partnership's performance obligation of natural gas deliveries is made at the agreed-upon delivery point.

Lastly, future revenues from the Partnership's firm capacity contracts include fixed revenues for the time periods when current rate settlements are in effect, which is approximately one to four years. Many of these contracts are long-term in nature and revenues from the remaining performance obligations on these contracts will be recognized using the FERC approved rates once the performance obligation to provide capacity has been satisfied.

## NOTE 7 DEBT AND CREDIT FACILITIES

(unaudited) (millions of dollars)	June 30, 2018	Weighted Average Interest Rate for the Six Months Ended June 30, 2018	December 31, 2017	Weighted Average Interest Rate for the Year Ended December 31, 2017
<b>TC PipeLines, LP</b>				
Senior Credit Facility due 2021	140	2.99%	185	2.41%
2013 Term Loan Facility due 2022	500	3.02%	500	2.33%
2015 Term Loan Facility due 2020	170	2.91%	170	2.22%
4.65% Unsecured Senior Notes due 2021	350	4.65% <sup>(a)</sup>	350	4.65% <sup>(a)</sup>
4.375% Unsecured Senior Notes due 2025	350	4.375% <sup>(a)</sup>	350	4.375% <sup>(a)</sup>
3.90% Unsecured Senior Notes due 2027	500	3.90% <sup>(a)</sup>	500	3.90% <sup>(a)</sup>
<b>GTN</b>				
5.29% Unsecured Senior Notes due 2020	100	5.29% <sup>(a)</sup>	100	5.29% <sup>(a)</sup>
5.69% Unsecured Senior Notes due 2035	150	5.69% <sup>(a)</sup>	150	5.69% <sup>(a)</sup>
Unsecured Term Loan Facility due 2019	35	2.71%	55	2.02%
<b>PNGTS</b>				
Revolving Credit Facility due 2023	—	—	—	—
5.90% Senior Secured Notes due 2018	—	—	30 <sup>(b)</sup>	5.90% <sup>(a)</sup>
<b>Tuscarora</b>				
Unsecured Term Loan due 2020	25	2.87%	25	2.27%
	<u>2,320</u>		<u>2,415</u>	
Less: unamortized debt issuance costs and debt discount	12		12	
Less: current portion	36		51 <sup>(b)</sup>	
	<u>2,272</u>		<u>2,352</u>	

<sup>(a)</sup> Fixed interest rate

<sup>(b)</sup> Includes the PNGTS portion due at December 31, 2017 amounting to \$5.8 million that was paid on January 2, 2018.

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### TC PipeLines, LP

The Partnership's Senior Credit Facility consists of a \$500 million senior revolving credit facility with a banking syndicate, maturing November 10, 2021, under which \$140 million was outstanding at June 30, 2018 (December 31, 2017 - \$185 million), leaving \$360 million available for future borrowing. The LIBOR-based interest rate on the Senior Credit Facility was 3.24 percent at June 30, 2018 (December 31, 2017 — 2.62 percent).

As of June 30, 2018, the variable interest rate exposure related to the 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 2.31 percent (December 31, 2017 — 2.31 percent). Prior to hedging activities, the LIBOR-based interest rate on the 2013 Term Loan Facility was 3.24 percent at June 30, 2018 (December 31, 2017 — 2.62 percent).

The LIBOR-based interest rate on the 2015 Term Loan Facility was 3.13 percent at June 30, 2018 (December 31, 2017 — 2.51 percent).

The 2013 Term Loan Facility and the 2015 Term Loan Facility (collectively, the Term Loan Facilities) and the Senior Credit Facility require the Partnership to maintain a certain leverage ratio (debt to adjusted cash flow [net income plus cash distributions received, extraordinary losses, interest expense, expense for taxes paid or accrued, and depreciation and amortization expense less equity earnings and extraordinary gains]) no greater than 5.00 to 1.00 for each fiscal quarter, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the leverage ratio is to be no greater than 5.50 to 1.00. The leverage ratio was 4.28 to 1.00 as of June 30, 2018.

### GTN

GTN's Unsecured Senior Notes, along with GTN's Unsecured Term Loan Facility contain a covenant that limits total debt to no greater than 70 percent of GTN's total capitalization. GTN's total debt to total capitalization ratio at June 30, 2018 was 42.3 percent. The LIBOR-based interest rate on the GTN's Unsecured Term Loan Facility was 2.93 percent at June 30, 2018 (December 31, 2017 — 2.31 percent).

### 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 (Revolving Credit Facility). 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 facility will be utilized primarily to fund the costs of the PXP expansion project and to finance PNGTS' other funding needs.

On May 10, 2018, PNGTS paid the remaining principal balance of its 5.90% Senior Secured Notes due 2018 (2003 Senior Secured Notes) using its available cash.

## Tuscarora

Tuscarora's Unsecured Term Loan contains a covenant that requires Tuscarora to maintain a debt service coverage ratio (cash available from operations divided by a sum of interest expense and principal payments) of greater than or equal to 3.00 to 1.00. As of June 30, 2018, the ratio was 11.2 to 1.00.

The LIBOR-based interest rate on the Tuscarora's Unsecured Term Loan Facility was 3.11 percent at June 30, 2018 (December 31, 2017 — 2.49 percent).

At June 30, 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 Third Amended and Restated Agreement of Limited Partnership (Partnership Agreement), incurring additional debt and distributions to unitholders. Refer also to Note 19 for important information relating to a distribution reduction to retain cash that will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage our financial metrics in response to the impact of the 2018 FERC Actions on our future operating performance and cashflows.

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

<b>(unaudited)</b> <b>(millions of dollars)</b>	
2018	1
2019	36
2020	293
2021	490
2022	500
Thereafter	1,000
	<u>2,320</u>

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### **NOTE 8 PARTNERS' EQUITY**

#### **ATM equity issuance program (ATM program)**

During the six months ended June 30, 2018, we issued 0.7 million common units under our ATM program (none during the three months ended June 30, 2018) generating net proceeds of approximately \$39 million, plus \$1 million contributed by the General Partner to maintain its effective two percent general partner interest. The commissions to our sales agents in the six months ended June 30, 2018 were nil. The net proceeds were used for general partnership purposes.

#### **Class B units issued to TransCanada**

The Class B Units issued on April 1, 2015 to finance a portion of the 2015 GTN Acquisition 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. Additionally, the Class B distribution will be further reduced by the percentage by which distributions payable to the common units is reduced for the calendar year (Class B Reduction).

For the year ending December 31, 2018, the Class B units' equity account will be increased by the excess of 30 percent of GTN's distributions less the annual threshold of \$20 million and the Class B Reduction and until such amount is declared for distribution and paid in the first quarter of 2019. During the six months ended June 30, 2018, the threshold was not exceeded.

For the year ended December 31, 2017, the Class B distribution was \$15 million and was declared and paid in the first quarter of 2018.

### **NOTE 9 NET INCOME PER COMMON UNIT**

Net income per common unit is computed by dividing net income attributable to controlling interests, after deduction of net income attributable to PNGTS' former parent, amounts attributable to the General Partner and Class B units, by the weighted average number of common units outstanding.

The amount allocable to the General Partner equals an amount based upon the General Partner's effective two percent general partner interest, plus an amount equal to incentive distributions. Incentive distributions are paid to the General Partner if quarterly cash distributions on the common units exceed levels specified in the Partnership Agreement.

The amount allocable to the Class B units in 2018 equals 30 percent of GTN's distributable cash flow during the year ended December 31, 2018 less \$20 million and the Class B Reduction (December 31, 2017 — \$20 million). During the three and six months ended June 30, 2018 and 2017, no amounts were allocated to the Class B units as the annual threshold was not exceeded.

Net income per common unit was determined as follows:

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<b>(unaudited)</b> <b>(millions of dollars, except per common unit amounts)</b>	<b>Three months ended</b>		<b>Six months ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2018</b>	<b>2017</b>	<b>2018</b>	<b>2017</b>

Net income attributable to controlling interests	73	55	169	132
Net income attributable to PNGTS' former parent <sup>(a)</sup>	—	—	—	(2)
Net income attributable to General and Limited Partners	73	55	169	130
Incentive distributions allocated to the General Partner <sup>(b)</sup>	—	(3)	—	(5)
Net income attributable to the General Partner and common units	73	52	169	125
Net income attributable to General Partner's two percent interest	(1)	(2)	(3)	(3)
<b>Net income attributable to common units</b>	<b>72</b>	<b>50</b>	<b>166</b>	<b>122</b>
Weighted average common units outstanding (millions) – basic and diluted	71.3	68.9	71.2	68.6
<b>Net income per common unit – basic and diluted</b>	<b>\$ 1.00</b>	<b>\$ 0.73</b>	<b>\$ 2.33</b>	<b>\$ 1.78</b>

<sup>(a)</sup> 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.

<sup>(b)</sup> 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.

## NOTE 10 CASH DISTRIBUTIONS

During the three and six months ended June 30, 2018, the Partnership distributed \$0.65 and \$1.65 per common unit, respectively, (June 30, 2017 — \$0.94 and \$1.88 per common unit, respectively) for a total of \$47 million and \$123 million, respectively, (June 30, 2017 - \$68 million and \$135 million, respectively).

The distribution paid to our General Partner during the three months ended June 30, 2018 for its effective two percent general partner interest was \$1 million (June 30, 2017 - \$1 million for the effective two percent interest and a \$2 million IDR payment). The General Partner did not receive any distributions in respect of its IDRs in the second quarter 2018.

The distribution paid to our General Partner during the six months ended June 30, 2018 for its effective two percent general partner interest was \$3 million along with an IDR payment of \$3 million for a total distribution of \$6 million (June 30, 2017 - \$2 million for the effective two percent interest and a \$4 million IDR payment).

## NOTE 11 CHANGE IN OPERATING WORKING CAPITAL

(unaudited) (millions of dollars)	Six months ended June 30,	
	2018	2017
Change in accounts receivable and other	2	11
Change in other current assets	(1)	2
Change in accounts payable and accrued liabilities <sup>(a)</sup>	(6)	(5)
Change in accounts payable to affiliates	—	(2)
Change in accrued interest	—	1
Change in operating working capital	(5)	7

<sup>(a)</sup> Excludes certain non-cash items primarily related to capital accruals.

## NOTE 12 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the General Partner. The General Partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the General Partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to conduct the business.

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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. For both the three and six months ended June 30, 2018 and 2017, total costs charged to the Partnership by the General Partner were \$1 million and \$2 million, respectively.

As operator of our pipelines except Iroquois, 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. Therefore, Iroquois does not receive any capital and operating services from TransCanada.

Capital and operating costs charged to our pipeline systems, except for Iroquois, for the three and six months ended June 30, 2018 and 2017 by TransCanada's subsidiaries and amounts payable to TransCanada's subsidiaries at June 30, 2018 and December 31, 2017 are summarized in the following tables:

(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017

Capital and operating costs charged by TransCanada's subsidiaries to:

Great Lakes <sup>(a)</sup>	16	9	24	17
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Northern Border <sup>(a)</sup>	9	10	18	20
GTN	8	9	16	16
Bison	1	1	3	2
North Baja	1	1	2	2
Tuscarora	1	1	2	2
PNGTS	2	2	4	4
Impact on the Partnership's net income:				
Great Lakes <sup>(a)</sup>	7	4	11	7
Northern Border <sup>(a)</sup>	4	4	8	7
GTN	7	7	14	14
Bison	1	1	3	2
North Baja	1	1	2	2
Tuscarora	1	1	2	2
PNGTS	1	1	2	2

(unaudited)  
(millions of dollars)

June 30, 2018

December 31, 2017

Net amounts payable to TransCanada's subsidiaries is as follows:

Great Lakes <sup>(a) (b)</sup>	3	3
Northern Border <sup>(a)</sup>	3	4
GTN	3	3
Bison	1	1
North Baja	—	—
Tuscarora	—	—
PNGTS <sup>(a)</sup>	1	1

<sup>(a)</sup> Represents 100 percent of the costs.

<sup>(b)</sup> Excludes any amounts owed to affiliates relating to revenue sharing. See discussion below.

### Great Lakes

Great Lakes earns significant transportation revenues from TransCanada and its affiliates, some of which are provided at discounted rates and some at maximum recourse rates. For the three and six months ended June 30, 2018, Great

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Lakes earned 72 percent and 70 percent, respectively, of transportation revenues from TransCanada and its affiliates (2017 — 43 percent and 57 percent, respectively).

At June 30, 2018, \$3 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. For the year ended December 31, 2017, Great Lakes recorded an estimated revenue sharing provision amounting to \$40 million. 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, its revenue sharing provision was eliminated (Refer to our Annual Report on Form 10-K for the year ended December 31, 2017).

During the second quarter of 2018, Great Lakes reached an agreement on the terms of a new long-term transportation capacity contracts with its affiliate, ANR Pipeline Company (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.

### PNGTS

PNGTS earns transportation revenues from TransCanada and its affiliates. For both three and six months ended June 30, 2018, PNGTS earned approximately \$1 million of its transportation revenues from TransCanada and its affiliates (2017 — nil).

At June 30, 2018, nil was included in PNGTS' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2017 — nil).

In connection with anticipated future commercial opportunities, PNGTS has entered into an arrangement with its affiliates regarding 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. At June 30, 2018, the total costs incurred by these affiliates was approximately \$15 million.

## NOTE 13 FAIR VALUE MEASUREMENTS

### (a) Fair Value Hierarchy



Under Accounting Standards Codification (ASC) 820, *Fair Value Measurements and Disclosures*, fair value measurements are characterized in one of three levels based upon the inputs 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 and accrued interest approximate their fair values because of the short maturity or duration of these instruments, or because the instruments bear a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership's 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.

Long-term debt is recorded at amortized cost and classified as Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified as 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

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prices. The estimated fair value of the Partnership's debt as at June 30, 2018 and December 31, 2017 was \$2,311 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. The Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps maturing July 1, 2018, at a weighted average fixed interest rate of 2.31 percent. At June 30, 2018, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of \$15 million (both on a 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 \$1 million and a gain of \$6 million for the three and six months ended June 30, 2018, respectively (2017 — nil and gain of \$1 million). During the three and six months ended June 30, 2018, gain of \$3 million was reclassified from other comprehensive income to net income (2017 — loss of \$1 million). For the three and six months ended June 30, 2018, the net realized gain related to the interest rate swaps was \$1 million and \$2 million, respectively, and was included in financial charges and other (2017 - nil) (Refer to Note 15).

The Partnership's \$500 million 2013 Term Loan is hedged using fixed interest rate swaps until July 1, 2018 at an average rate of 2.31 percent. During the fourth quarter of 2017, the Partnership implemented an interest rate hedging strategy that hedged the \$500 million 2013 Term Loan until its October 2, 2022 maturity using forward starting swaps at an average rate of 3.26 percent.

The Partnership has no master netting agreements; however, it has derivative contracts containing 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 June 30, 2018 (net asset of \$5 million as of December 31, 2017).

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with Accounting Standards Codification (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 accumulated other comprehensive income as of the termination date. The previously recorded loss was amortized against earnings over the life of the PNGTS Senior Secured Notes. On May 10, 2018, PNGTS paid the remaining principal balance of its 2003 Senior Secured Notes using its available cash and, as a result, our 61.71 percent proportionate share of the net unamortized loss on PNGTS included in other comprehensive income was all amortized against earnings (December 31, 2017 - \$1 million). For the three and six months ended June 30, 2018, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was \$1 million (2017 - \$1 million).

## NOTE 14 ACCOUNTS RECEIVABLE AND OTHER

(unaudited) (millions of dollars)	June 30, 2018	December 31, 2017
Trade accounts receivable, net of allowance of nil	37	40
Imbalance receivable from affiliates	1	1
Other	2	1
	<u>40</u>	<u>42</u>

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## NOTE 15 FINANCIAL CHARGES AND OTHER

(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Interest Expense <sup>(a)</sup>	24	19	48	36
PNGTS' amortization of loss on derivative instruments (Note 13)	2	1	2	1
Net realized gain related to the interest rate swaps	(1)	—	(2)	—
Other Income	(2)	(1)	(2)	(1)
	<u>23</u>	<u>19</u>	<u>46</u>	<u>36</u>

<sup>(a)</sup> Includes amortization of debt issuance costs and discount costs.

## NOTE 16 CONTINGENCIES

*Great Lakes v. Essar Steel Minnesota LLC, et al.* — On October 29, 2009, Great Lakes filed suit in the U.S. District Court, District of Minnesota, against Essar Minnesota LLC (Essar Minnesota) and certain Foreign Essar Affiliates (collectively, Essar) for breach of its monthly payment obligation under its transportation services agreement with Great Lakes. Great Lakes sought to recover approximately \$33 million for past and future payments due under the agreement. In September 2015, the federal district court judge entered a judgment in the amount of \$32.9 million in favor of Great Lakes. Essar successfully appealed this decision to the United States Court of Appeals for the Eighth Circuit (Eighth Circuit) based on an allegation of improper jurisdiction and various other rulings by the federal district judge. The Eighth Circuit vacated Great Lakes' judgment against Essar finding that there was no federal jurisdiction. In May 2017, the federal district court awarded Essar Minnesota approximately \$1.2 million for costs, including recovery of the premium for the performance bond Essar was required to post pending appeal.

Essar Minnesota filed for bankruptcy in July 2016. Following Essar's successful appeal and award of \$1.2 million of costs, Great Lakes was required to release the \$1.2 million into the bankruptcy estates. Great Lakes filed a claim against Essar Minnesota in the bankruptcy court. The bankruptcy court approved Great Lakes' unsecured claim in the amount of \$31.5 million in April 2017. Great Lakes is unable to estimate the timing or the extent to which its claim will be recoverable in the bankruptcy proceedings.

The Foreign Essar Affiliates have not filed for bankruptcy and Great Lakes' case against the Foreign Essar Affiliates in Minnesota state court remains pending. The Foreign Essar Affiliates gave an offer of judgment (Offer of Judgment) in the federal district court proceeding whereby the Foreign Essar Affiliates agreed to satisfy any judgment awarded to Great Lakes. The Foreign Essar Affiliates dispute that the Offer of Judgment is enforceable because the federal court judgment was vacated on appeal. Great Lakes has obtained a consent order from the bankruptcy court permitting it to petition the state court to enforce the Offer of Judgment. If unsuccessful in state court, Great Lakes can return to bankruptcy court for an order permitting it to proceed to trial in state court on its claims under the transportation services agreement against the Foreign Essar Affiliates.

At June 30, 2018, Great Lakes is unable to estimate the timing or the extent to which its claim will be recoverable in the bankruptcy proceedings, therefore, it did not recognize any gain contingency on its outstanding claim against Essar.

Additionally, at June 30, 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 17 VARIABLE INTEREST ENTITIES

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

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

### Consolidated VIEs

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

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

(unaudited) (millions of dollars)	June 30, 2018	December 31, 2017
--------------------------------------	---------------	-------------------

<b>ASSETS (LIABILITIES) *</b>		
Cash and cash equivalents	7	19
Accounts receivable and other	27	30
Inventories	7	6
Other current assets	6	5
Equity investments	1,211	1,213
Plant, property and equipment, net	1,117	1,133
Other assets	2	1
Accounts payable and accrued liabilities	(18)	(24)
Accounts payable to affiliates, net	(44)	(42)
Distributions payable	—	(1)
Accrued interest	(3)	(2)
Current portion of long-term debt	(36)	(51)
Long-term debt	(273)	(308)
Other liabilities	(27)	(26)
Deferred state income tax	(10)	(10)

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

## NOTE 18 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. 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 June 30, 2018 and December 31, 2017 relate primarily to utility plant. At June 30, 2018 and December 31, 2017 the New Hampshire BPT effective tax rate was 3.8 percent for both periods and was applied to PNGTS' taxable income.

(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
State income taxes				
Current	—	—	1	1
Deferred	—	—	—	—
	—	—	1	1

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## NOTE 19 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through August 2, 2018, the date the financial statements were issued, and concluded there were no events or transactions during this period that would require recognition or disclosure in the consolidated financial statements other than what is disclosed here and/or those already disclosed in the preceding notes.

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 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 effective two percent general partner interest. The General Partner did not receive any distributions in respect of its IDRs for the second quarter 2018. This distribution and our first quarter 2018 distribution each represent a 35 percent reduction compared to the Partnership's fourth quarter 2017 distribution of \$1.00 per common unit. Cash retained by the Partnership will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage our financial metrics in response to the impact of the 2018 FERC Actions on our future operating performance and cash flows.

Northern Border declared its June 2018 distribution of \$12 million on July 11, 2018, of which the Partnership received its 50 percent share or \$6 million on July 31, 2018.

Great Lakes declared its second quarter 2018 distribution of \$29 million on July 17, 2018, of which the Partnership received its 46.45 percent share or \$13 million on August 1, 2018.

PNGTS declared its second quarter 2018 distribution of \$3 million on July 20, 2018, of which \$1 million will be paid to its non-controlling interest owner on August 1, 2018.

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## Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the unaudited financial statements and notes included in Item 1 "Financial Statements" of this Quarterly Report on Form 10-Q, as well as our Annual Report on Form 10-K for the year ended December 31, 2017.

## RECENT BUSINESS DEVELOPMENTS

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 an MLP receiving a tax allowance and a return on equity derived from the 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. We are 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, (2) the NOPR and (3) the NOI. On July 18, 2018, FERC issued (1) Order on Rehearing and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR. The Final Rule will become effective September 13, 2018, and is subject to requests for further rehearing and clarification. 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 Tax Law Changes for Interstate Natural Gas Companies***

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rates settlement or (ii) file a one-time report, called FERC Form No. 501-G, that quantifies 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 will have four options:

- 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 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

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- liability, this elimination would have the effect of increasing the pipeline’s rate base used for rate-making purposes;
- 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 either by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date;
- file a statement explaining its rationale for why it does not believe the pipeline’s rates must change; and
- take no 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.

We continue to evaluate this Final Rule and our next course of action, however, we do not expect an immediate or a retroactive impact from the Final Rule or the Revised Policy Statement described above.

### ***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 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.

### ***Partnership Specific Considerations***

While certain uncertainties exist with respect to changes resulting from the 2018 FERC Actions, the net effect of the potential reduction of our pipeline systems’ maximum allowable or recourse rates on the Partnership’s revenues could have a material negative impact on the earnings, cash flow, and financial position of the Partnership and could diminish its relative ability to attract capital to fund future growth. The Partnership’s pipeline systems do not currently have a requirement to file for new rates earlier than 2022 as a result of their existing rate settlements. However, the timing may be accelerated by the Final

Rule and represents a revision of our previous expectations. Proceedings related to the 2018 FERC Actions could begin as early as late 2018 and could result in a reset of certain of our pipelines' maximum allowable rates.

While the Partnership does not anticipate any FERC mandated action to reduce recourse rates in 2018, the Partnership believes that any impact would take effect prospectively upon the completion or settlement of a rate case, including one that may be initiated by the FERC or customers. Should the Partnership choose to proactively address the issues contemplated by the 2018 FERC Actions, prospective changes in our pipeline systems' revenues could occur as early as late 2018.

The 2018 FERC Actions directly address two components of our pipeline systems' cost of service based rates: the allowance for income taxes and the amount of ADIT. 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, including those partially owned by corporations such as Great Lakes, Northern Border, Iroquois and PNGTS pipelines. Additionally, FERC has indicated that any rate reduction is not expected to affect negotiated rate or non-recourse rate contracts.

Given the potential variability of outcomes arising from the 2018 FERC Actions, we are unable to precisely quantify the ultimate timing and amount of the reductions in revenue and earnings on our future operating performance and cash flows. The Partnership continues to re-examine its next steps following the changes noted above and alternatives now available under the Final Rule. As noted above, the change in the Final Rule to allow MLPs to remove the ADIT liability from rate base, and thus increase net recoverable rate base, would partially mitigate the loss of the tax allowance in cost-of-service based rates. Various uncertainties still exist around an optimized approach for our assets, however, we do believe that the range of possible outcomes has improved when compared to the estimated outcomes based on the 2018 FERC Actions proposed in March 2018. Currently, the estimated overall impact of the tax-related changes to our revenue and cashflow is in a range of negative \$40 million to \$60 million per year as we execute our regulatory strategies through the process initiated by these FERC Actions. These estimates could change due to numerous assumptions around the resolution of related issues as they are applied individually across our pipeline systems. In addition, approximately half of the Partnership's share of revenues (including those accounted for in the earnings of our equity investments) are derived from contracts that are non-recourse, which are not expected to be impacted by the 2018

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FERC Actions. Accordingly, any reduction to the recourse rates would not have a proportional reduction on overall revenues.

### **Partnership Response and Outlook of Our Business**

While revenues from our pipeline systems are not expected to decrease prior to individual rate proceedings, the Partnership took proactive measures to conserve capital for near-term capital requirements and to manage its leverage metrics given the magnitude and timing of the potential future cash flow decreases as a result of the 2018 FERC Actions.

Accordingly, the Partnership reduced its first and second quarter 2018 cash distributions to unitholders to \$0.65 per quarter representing a 35 percent reduction from its fourth quarter 2017 distribution of \$1.00 per common unit. Cash retained by the Partnership will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage our financial metrics in anticipation of the reduction of revenues should our pipeline systems' rates be reset in response to the 2018 FERC Actions that could begin as early as late 2018.

TransCanada, the ultimate parent company of our General Partner, has historically viewed us as an element of its capital financing strategy. Following the 2018 FERC Actions initially proposed in March 2018, TransCanada stated that further dropdowns to the Partnership were no longer considered to be a viable funding lever. As a result of the Final Rule issued on July 18, 2018, TransCanada continues to monitor developments in the Partnership in order to determine whether the Partnership might be restored as a competitive financing option in the future. Therefore, our traditional source of growth is currently not accessible under the current circumstances, and our options for further growth could be significantly limited. We are continuing to consider various options that would best position the Partnership for the long term to further minimize any negative effects of the 2018 FERC Actions. To respond to new information or changes in strategies in the future, the Partnership may consider further distribution level changes, either as a standalone action or in combination with other strategies.

Our focus remains on safe and reliable operations of our pipeline assets and we expect our assets to continue to serve their customers as designed.

### **Impairment Considerations**

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 review property, plant and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstance indicate that it might be impaired. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, an impairment test is not performed.

Until the 2018 FERC Actions are implemented through individual proceedings or settlements, and we have fully evaluated our respective alternatives to minimize any negative impact, we believe that it is not more likely than not that the fair values of our reporting units are less than their respective carrying values. Therefore, a goodwill impairment test was not performed. Also, we have determined there is no indication that the carrying values of property, plant and equipment and equity investments potentially impacted by the 2018 FERC Actions are not recoverable. We will continue to monitor developments and assess our goodwill for impairment. We will also review our property, plant and equipment and equity investments for recoverability as new information becomes available.

At December 31, 2017, the estimated fair value of our investment in Great Lakes exceeded its carrying value by less than 10 percent. There is a risk that the 2018 FERC Actions, once implemented through the individual rate proceeding or settlement, could result to an impairment charge to our equity method

goodwill on Great Lakes amounting to \$260 million at June 30, 2018 (December 31, 2017 — \$260 million). Additionally, since the estimated fair value of Tuscarora exceeded its carrying value by less than 10 percent in its most recent valuation, there is also a risk that the \$82 million goodwill at June 30, 2018 (December 31, 2017 - \$82 million) related to Tuscarora could be negatively impacted by the 2018 FERC Actions once implemented through the individual rate proceeding or settlement.

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**Other Business Developments**

*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 it will change anything for proposed natural gas pipeline projects. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

*Portland XPress Project* - As noted in our Annual Report for the year ended December 31, 2017, the in-service dates of PXP are being phased-in over a three-year period beginning November 1, 2018. During the second quarter, PNGTS filed the required applications with FERC for all three phases of the project, which includes 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 additional volumes of natural gas to New England.

**HOW WE EVALUATE OUR OPERATIONS**

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

**EBITDA**

We use EBITDA as a proxy of our operating cash flow and current operating profitability.

**Distributable Cash Flows**

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

Please see “Non-GAAP Financial Measures: EBITDA and Distributable Cash Flow” for more information.

**RESULTS OF OPERATIONS**

Our ownership interests in eight pipelines were our only material sources of income during the period. Therefore, our results of operations and cash flows were influenced by, and reflect the same factors that influenced, our pipeline systems.

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(unaudited) (millions of dollars)	Three months ended June 30,		\$ Change <sup>(a)</sup>	% Change <sup>(a)</sup>	Six months ended June 30,		\$ Change <sup>(a)</sup>	% Change <sup>(a)</sup>
	2018	2017			2018	2017		
Transmission revenues	111	101	10	10	226	213	13	6
Equity earnings	36	24	12	50	95	60	35	58
Operating, maintenance and administrative	(25)	(26)	1	4	(49)	(49)	—	—
Depreciation	(24)	(25)	1	4	(48)	(49)	1	2
Financial charges and other	(23)	(19)	(4)	(21)	(46)	(36)	(10)	(28)
<b>Net income before taxes</b>	<b>75</b>	<b>55</b>	<b>20</b>	<b>36</b>	<b>178</b>	<b>139</b>	<b>39</b>	<b>28</b>
State income taxes	—	—	—	—	(1)	(1)	—	—
<b>Net income</b>	<b>75</b>	<b>55</b>	<b>20</b>		<b>177</b>	<b>138</b>	<b>39</b>	
Net income attributable to non-controlling interests	2	—	2	—	8	6	2	(33)
<b>Net income attributable to controlling interests</b>	<b>73</b>	<b>55</b>	<b>18</b>	<b>33</b>	<b>169</b>	<b>132</b>	<b>37</b>	<b>28</b>

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

**Three Months Ended June 30, 2018 compared to Same Period in 2017**

The Partnership’s net income attributable to controlling interests increased by \$18 million in the three months ended June 30, 2018 compared to 2017, an increase of \$0.27 per common unit, mainly due to the following:

*Transmission revenues* — Revenues were higher due largely to incremental long-term services sold by GTN associated with the increased available upstream capacity following debottlenecking activities on TransCanada’s pipelines offset by lower revenues from GTN’s short-term discretionary services. Additionally, PNGTS’ revenue increased primarily due to incremental contracting from PNGTS’ Continent-to-Coast contracts with several shippers for a term of 15 years for approximately 82,000 Dth/day (C2C contracts).

*Equity Earnings* - The \$12 million increase was primarily due to the inclusion of equity earnings from Iroquois for the full three months of the second quarter of 2018 compared to only one month in 2017 (our 49.34 percent ownership was effective June 1, 2017) and higher equity earnings from Great Lakes as a result of incremental seasonal winter sales during the current period and the elimination of Great Lakes’ revenue sharing mechanism beginning in 2018 as part of the 2017 Great Lakes Settlement.

*Financial charges and other* - The \$4 million increase was primarily attributable to additional borrowings to finance the 2017 Acquisition.

*Net income attributable to non-controlling interests* - The Partnership’s net income attributable to non-controlling interests was higher due to the increase in PNGTS’ net income as a result of its higher revenue.

**Six Months Ended June 30, 2018 compared to Same Period in 2017**

The Partnership’s net income attributable to controlling interests increased by \$37 million in the six months ended June 30, 2018 compared to 2017, an increase of \$0.55 per common unit, mainly due to the following:

*Transmission revenues* — Revenues were higher due largely to incremental long-term services sold by GTN associated with the increased available upstream capacity following debottlenecking activities on TransCanada’s pipelines. Additionally, PNGTS’ revenue increased primarily due to incremental contracting from PNGTS’ C2C contracts partially offset by certain expiring winter contracts and North Baja experienced an increase in short-term firm transportation services.

*Equity Earnings* - The \$35 million increase was primarily due to the inclusion of equity earnings from Iroquois for the full six months of 2018 compared to only one month in 2017 (our 49.34 percent ownership was effective June 1, 2017), as well as the increase in Iroquois’ short-term discretionary services 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 incremental

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seasonal winter sales during the current period and the elimination of Great Lakes’ revenue sharing mechanism beginning in 2018 as part of the 2017 Great Lakes Settlement. The additional earnings were partially offset by lower revenues and earnings from Northern Border resulting from its rate reduction as part of the 2017 Northern Border Settlement.

*Financial charges and other* - The \$10 million increase was primarily attributable to additional borrowings to finance the 2017 Acquisition.

*Net income attributable to non-controlling interests* - The Partnership’s net income attributable to non-controlling interests was higher due to the increase in PNGTS’ net income as a result of its higher revenue.

**Net Income Attributable to Common Units and Net Income per Common Unit**

As discussed in Note 9 within Item 1 “Financial Statements,” we will allocate a portion of the Partnership’s income to the Class B Units after the annual threshold is exceeded which will effectively reduce the income allocable to the common units and net income per common unit. Currently, we expect to allocate a portion of the Partnership’s income to the Class B units at the end of the third quarter of 2018. Please also read Note 8 within Item 1 “Financial Statements,” for additional disclosures on the Class B units.

**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 its operating expenses, debt service and cash distributions (including those distributions made to TransCanada through our General Partner and as holder of all our Class B units) primarily with operating cash flow.

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 will be used to fund ongoing capital expenditures and the repayment of debt to levels that prudently manage its financial metrics given the magnitude and timing of the potential future cash flow decreases as a result of the 2018 FERC Actions.

As of June 30, 2018, we had \$51 million of cash and cash equivalents, an increase of \$18 million or 55 percent from December 31, 2017, and we have reduced the outstanding balance of our Senior Credit Facility by 24 percent, from \$185 million at December 31, 2017 to \$140 million at June 30, 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 liquidity requirements over the next twelve months, 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:

<b>(unaudited) (millions of dollars)</b>	<b>June 30, 2018</b>	<b>December 31, 2017</b>
Total capacity under the Senior Credit Facility	500	500
Less: Outstanding borrowings under the Senior Credit Facility	140	185

The principal sources of liquidity on our pipeline systems 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.

Capital expenditures of our pipeline systems 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.

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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.

### **Cash Flow Analysis for the Six Months Ended June 30, 2018 compared to Same Period in 2017**

(unaudited) (millions of dollars)	Six months ended June 30,	
	2018	2017
Net cash provided by (used in):		
Operating activities	223	205
Investing activities	(8)	(625)
Financing activities	(197)	407
<b>Net increase in cash and cash equivalents</b>	<b>18</b>	<b>(13)</b>
Cash and cash equivalents at beginning of the period	33	64
<b>Cash and cash equivalents at end of the period</b>	<b>51</b>	<b>51</b>

### **Operating Cash Flows**

Net cash provided by operating activities increased by \$18 million in the six months ended June 30, 2018 compared to the same period in 2017 primarily due to the net effect of:

- higher cash flow from operations at GTN, PNGTS and North Baja primarily resulting from an increase in their revenues;
- distributions received from Iroquois resulting from the addition of Iroquois to our portfolio of assets effective June 1, 2017;
- higher interest expense attributable to additional borrowings to finance the acquisition of a 49.34 percent interest in Iroquois and an additional 11.81 percent interest in PNGTS (the 2017 Acquisition); and
- higher distributions received from Great Lakes due to an increase in its revenue in the fourth quarter of 2017 and first quarter of 2018 compared to the same periods of the previous years.

### **Investing Cash Flows**

Net cash used in investing activities decreased by \$617 million during the six months ended June 30, 2018 compared to the same period in 2017 due to the net effect of:

- \$605 million cash payment on June 1, 2017 to TransCanada for the 2017 Acquisition;
- lower capital maintenance expenditures in the first six months of 2018 compared to 2017, during which period there were major compression equipment overhauls on GTN; and
- \$5 million unrestricted cash distribution we received from Iroquois during the six months ended June 30, 2018 representing a return of investment (none received in 2017).

### **Financing Cash Flows**

The net increase in cash used in financing activities was approximately \$604 million in the six months ended June 30, 2018 compared to the same period in 2017 primarily due to the net effect of:

- \$95 million in net debt repayments in 2018 compared to \$479 million net debt issuance in 2017 primarily due to the issuance of \$500 million 3.90% Senior Notes on May 25, 2017 to partially finance the 2017 Acquisition;
- \$12 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 reduction in distributions declared and paid for the first quarter of 2018 as compared to 2017;
- \$7 million decrease in distributions paid to Class B units in 2018 as compared to 2017;
- \$52 million decrease in our ATM equity issuances in the six months ended June 30, 2018, as compared to the same period in 2017;
- \$2 million decrease in distributions paid to non-controlling interests due to lower distributions from PNGTS in the first six months of 2018 as compared to the first six months of 2017 to retain cash to repay the remaining balance on its Senior Notes; and

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- \$1 million decrease in distributions paid to TransCanada as the former parent of PNGTS due to the Partnership's acquisition of TransCanada's then-remaining 11.81 percent interest in PNGTS effective June 1, 2017.



## Short-Term Cash Flow Outlook

### Operating Cash Flow Outlook

Northern Border declared its June 2018 distribution of \$12 million on July 11, 2018, of which the Partnership received its 50 percent share or \$6 million. The distribution was paid on July 31, 2018.

Great Lakes declared its second quarter 2018 distribution of \$29 million on July 17, 2018, of which the Partnership received its 46.45 percent share or \$13 million. The distribution was paid on August 1, 2018.

Iroquois declared its second quarter 2018 distribution of \$29 million on July 25, 2018, of which the Partnership received its 49.34 percent share or \$14 million on August 1, 2018.

Our equity investee Iroquois has \$2 million of scheduled debt repayments for the remainder of 2018 and Iroquois' debt repayments are expected to be funded through its cash flow from operations.

### Investing Cash Flow Outlook

The Partnership made an equity contribution to Great Lakes of \$4 million in the first quarter of 2018. This amount represents the Partnership's 46.45 percent share of a \$9 million cash call from Great Lakes to make a scheduled debt repayment. The Partnership expects to make an additional \$5 million equity contribution to Great Lakes in the fourth quarter of 2018 to further fund debt repayments. This is consistent with prior years.

Our consolidated entities have commitments of \$3 million as of June 30, 2018 in connection with various maintenance and general plant projects.

### Financing Cash Flow Outlook

On July 26, 2018, the board of directors of our 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. Please see "Recent Business Developments" and Note 19 within Item 1 "Financial Statements" for additional disclosures.

On April 5, 2018, PNGTS entered into a \$125 million Revolving Credit Facility. The facility will be utilized primarily to fund the costs of the PXP expansion project and to finance PNGTS' other funding needs. As of August 2, 2018, PNGTS has not utilized its \$125 million Revolving Credit Facility.

On May 10, 2018, PNGTS paid the remaining principal balance of its 2003 Senior Secured Notes using available cash.

PNGTS declared its second quarter 2018 distribution of \$3 million on July 20, 2018, of which \$1 million will be paid to its non-controlling interest owner on August 1, 2018.

## Non-GAAP Financial Measures: EBITDA and Distributable Cash Flow

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

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

Total distributable cash flow includes EBITDA *plus*:

- Distributions from our equity investments

less:

- Earnings from our equity investments,
- Equity allowance for funds used during construction (Equity AFUDC),

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- Interest expense,
- Income taxes,
- Distributions to non-controlling interests,
- Distributions to TransCanada as the former parent of PNGTS, and
- Maintenance capital expenditures from consolidated subsidiaries.

Distributable cash flow is computed net of distributions declared to the General Partner and distributions allocable to Class B units. Distributions declared to the General Partner are based on its effective two percent interest plus an amount equal to incentive distributions. Distributions allocable to the Class B units in 2018 equal 30 percent of GTN's distributable cash flow less \$20 million and the Class B Reduction.

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

The non-GAAP measures described above are provided as a supplement to GAAP financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP. Additionally, these measures as presented may not be comparable to similarly titled measures of other companies.

## Reconciliations of Net Income to EBITDA and Distributable Cash Flow

The following table represents a reconciliation of the non-GAAP financial measures of EBITDA, total distributable cash flow and distributable cash flow, to the most directly comparable GAAP financial measure of Net Income:

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(unaudited) (millions of dollars)	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
<b>Net income</b>	<b>75</b>	<b>55</b>	<b>177</b>	<b>138</b>
Add:				
Interest expense <sup>(a)</sup>	25	20	48	37
Depreciation and amortization	24	25	48	49
Income taxes	—	—	1	1
<b>EBITDA</b>	<b>124</b>	<b>100</b>	<b>274</b>	<b>225</b>
Add:				
Distributions from equity investments <sup>(b)</sup>				
Northern Border	18	20	37	40
Great Lakes	14	7	39	27
Iroquois <sup>(c)</sup>	14	14	28	14
	<b>46</b>	<b>41</b>	<b>104</b>	<b>81</b>
Less:				
Equity earnings:				
Northern Border	(15)	(15)	(32)	(34)
Great Lakes	(12)	(6)	(36)	(23)
Iroquois	(9)	(3)	(27)	(3)
	<b>(36)</b>	<b>(24)</b>	<b>(95)</b>	<b>(60)</b>
Less:				
Interest expense	(25)	(20)	(48)	(37)
Income taxes	—	—	(1)	(1)
Distributions to non-controlling interests <sup>(d)</sup>	(2)	(3)	(9)	(8)
Distributions to TransCanada as PNGTS' former parent <sup>(e)</sup>	—	—	—	(1)
Maintenance capital expenditures <sup>(f)</sup>	(5)	(7)	(10)	(17)
	<b>(32)</b>	<b>(30)</b>	<b>(68)</b>	<b>(64)</b>
<b>Total Distributable Cash Flow</b>	<b>102</b>	<b>87</b>	<b>215</b>	<b>182</b>
General Partner distributions declared <sup>(g)</sup>	(1)	(5)	(2)	(8)
Distributions allocable to Class B units <sup>(h)</sup>	—	—	—	—
<b>Distributable Cash Flow</b>	<b>101</b>	<b>82</b>	<b>213</b>	<b>174</b>

(a) Interest expense as presented includes net realized loss or gain related to the interest rate swaps and amortization of realized loss on PNGTS' derivative instruments. Refer to Note 15 within Item 1 "Financial Statements".

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

(c) This amount represents our proportional 49.34 percent share of the distribution declared by our equity investee Iroquois during the current reporting period and includes our 49.34 percent share of the Iroquois unrestricted cash distribution amounting to approximately \$2.6 million and \$5.2 million, respectively, for the three and six months ended June 30, 2018 (2017 - \$2.6 million for both periods).

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

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

(f) The Partnership's maintenance capital expenditures include expenditures made to maintain, over the long term, the operating capacity, system integrity and reliability of our pipeline assets. 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 for 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.

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(g) Distributions declared to the General Partner for the three and six months ended June 30, 2018 did not trigger any incentive distribution (2017 — \$3 million and \$5 million).

(h) During the six months ended June 30, 2018 and 2017, no distributions were allocated to the Class B units as the annual threshold had not been exceeded. We expect the 2018 threshold will be exceeded at the end of the third quarter of 2018. Please read Notes 8 and 9 within Item 1 "Financial Statements" for additional disclosures on the Class B units.

### Three months ended June 30, 2018 Compared to Same Period in 2017

Our EBITDA was higher for the second quarter of 2018 compared to the same period in 2017 primarily due to higher equity earnings and an overall increase in our revenues during the period as discussed in more detail under the Results of Operations section.

Our distributable cash flow increased by \$19 million in the second quarter of 2018 compared to the same period in 2017 due to the net effect of:

- higher EBITDA from GTN and PNGTS due to an increase in their revenues generated during the second quarter of 2018;
- higher distributions from Great Lakes due to the increase in revenue during the second quarter of 2018;
- lower maintenance capital expenditures compared to the second quarter of 2017, during which there were major compression equipment overhauls on GTN;
- increased interest expense due to additional borrowings to finance the 2017 Acquisition; and
- reduction in our declared distributions which did not result in any IDR allocation to our General Partner during the current period.

### Six months ended June 30, 2018 Compared to Same Period in 2017

Our EBITDA was higher for the six months ended June 30, 2018 compared to the same period in 2017 primarily due to higher equity earnings and an overall increase in our revenues during the period as discussed in more detail under the Results of Operations section.

Our distributable cash flow increased by \$39 million in the six months ended June 30, 2018 compared to the same period in 2017 due to the net effect of:

- higher EBITDA from GTN, PNGTS and North Baja due to an increase in their revenues generated during the six months ended June 30, 2018;
- two quarters of distributions received from Iroquois during the six months ended June 30, 2018 compared to one distribution received during the previous period (ownership of 49.34 percent was effective June 1, 2017);
- higher distributions from Great Lakes due to the increase in revenue generated during the six months ended June 30, 2018;
- lower maintenance capital expenditures compared to 2017 during which there were major compression equipment overhauls on GTN;
- increased interest expense due to additional borrowings to finance the 2017 Acquisition; and
- reduction in declared distributions which did not result in any IDR allocation to our General Partner during the current period.

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### Contractual Obligations

#### The Partnership's Contractual Obligations

The Partnership's contractual obligations related to debt as of June 30, 2018 included the following:

(unaudited) (millions of dollars)	Payments Due by Period					Weighted Average Interest Rate for the Six Months Ended June 30, 2018
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	
<b>TC PipeLines, LP</b>						
Senior Credit Facility due 2021	140	—	—	140	—	2.99%
2013 Term Loan Facility due 2022	500	—	—	500	—	3.02%
2015 Term Loan Facility due 2020	170	—	170	—	—	2.91%
4.65% Senior Notes due 2021	350	—	350	—	—	4.65% <sup>(a)</sup>
4.375% Senior Notes due 2025	350	—	—	—	350	4.375% <sup>(a)</sup>
3.9% Senior Notes due 2027	500	—	—	—	500	3.90% <sup>(a)</sup>
<b>GTN</b>						
5.29% Unsecured Senior Notes due 2020	100	—	100	—	—	5.29% <sup>(a)</sup>
5.69% Unsecured Senior Notes due 2035	150	—	—	—	150	5.69% <sup>(a)</sup>
Unsecured Term Loan Facility due 2019	35	35	—	—	—	2.71%
<b>PNGTS</b>						
Revolving Credit Facility due 2023	—	—	—	—	—	—
<b>Tuscarora</b>						
Unsecured Term Loan due 2020	25	1	24	—	—	2.87%
	<u>2,320</u>	<u>36</u>	<u>644</u>	<u>640</u>	<u>1,000</u>	

<sup>(a)</sup> Fixed interest rate

The Partnership's long-term debt results in exposures to changing interest rates. The Partnership uses derivatives to assist in managing its exposure to interest rate risk. Refer to Item 3. "Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding the derivatives.

The fair value of the Partnership's long-term debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates. The estimated fair value of the Partnership's debt at June 30, 2018 was \$2,311 million.

Please read Note 7 within Item 1. "Financial Statements" for additional information regarding the Partnership's debt.

#### Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations related to debt as of June 30, 2018 included the following:

(unaudited) (millions of dollars)	Payments Due by Period <sup>(a)</sup>					Weighted Average Interest Rate for the Six Months Ended June 30, 2018
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	
\$200 million Credit Agreement due 2020	15	—	15	—	—	2.94%
7.50% Senior Notes due 2021	250	—	—	250	—	7.50% <sup>(b)</sup>
	265	—	15	250	—	

<sup>(a)</sup> Represents 100 percent of Northern Border's debt obligations

<sup>(b)</sup> Fixed interest rate

As of June 30, 2018, \$15 million was outstanding under Northern Border's \$200 million revolving credit agreement, leaving \$185 million available for future borrowings. At June 30, 2018, Northern Border was in compliance with all of its financial covenants.

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Northern Border has commitments of \$5 million as of June 30, 2018 in connection with the meter station growth project, the compressor station overhaul project and other capital projects.

### Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations related to debt as of June 30, 2018 included the following:

(unaudited) (millions of dollars)	Payments Due by Period <sup>(a)</sup>					Weighted Average Interest Rate for the Six Months Ended June 30, 2018
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	
9.09% series Senior Notes due 2018 - 2021	40	10	20	10	—	9.09% <sup>(b)</sup>
6.95% series Senior Notes due 2019 - 2028	110	11	22	22	55	6.95% <sup>(b)</sup>
8.08% series Senior Notes due 2021 - 2030	100	—	10	20	70	8.08% <sup>(b)</sup>
	250	21	52	52	125	

<sup>(a)</sup> Represents 100 percent of Great Lakes' debt obligations

<sup>(b)</sup> Fixed interest rate

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the senior note agreements, approximately \$135 million of Great Lakes' partners' capital was restricted as to distributions as of June 30, 2018 (December 31, 2017 — \$139 million). Great Lakes was in compliance with all of its financial covenants at June 30, 2018.

Great Lakes has commitments of \$3 million as of June 30, 2018 in connection with pipeline integrity program spending, major overhaul projects, and right of way renewals.

### Summary of Iroquois' Contractual Obligations

Iroquois' contractual obligations related to debt as of June 30, 2018 included the following:

(unaudited) (millions of dollars)	Payments Due by Period <sup>(a)</sup>					Weighted Average Interest Rate for the Six Months Ended June 30, 2018
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	
6.63% series Senior Notes due 2019	140	140	—	—	—	6.63% <sup>(b)</sup>
4.84% series Senior Notes due 2020	150	—	150	—	—	4.84% <sup>(b)</sup>
6.10% series Senior Notes due 2027	37	5	9	7	16	6.10% <sup>(b)</sup>
	327	145	159	7	16	

<sup>(a)</sup> Represents 100 percent of Iroquois' debt obligations.

<sup>(b)</sup> Fixed interest rate

Iroquois has commitments of \$2 million as of June 30, 2018 relative to procurement of materials on its expansion project.

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 June 30, 2018, the debt/capitalization ratio was 47.4% and the debt service coverage ratio was 6.24 times, therefore, Iroquois was not restricted from making any cash distributions.

## RELATED PARTY TRANSACTIONS

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**Item 3. 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 floating rate 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 June 30, 2018, the Partnership's interest rate exposure resulted from our floating rate Senior Credit Facility, 2015 Term Loan Facility, GTN's Unsecured Term Loan Facility, PNGTS' Revolving Credit Facility and Tuscarora's Unsecured Term Loan Facility, under which \$370 million, or 16 percent, of our outstanding debt was subject to variability in LIBOR interest rates (December 31, 2017- \$435 million or 18 percent). As of June 30, 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 2.31 percent.

If interest rates hypothetically increased (decreased) on these facilities by one percent (100 basis points), compared with rates in effect at June 30, 2018, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately \$4 million.

As of June 30, 2018, \$15 million, or 6 percent, of Northern Border's outstanding debt was at floating rates. If interest rates hypothetically increased (decreased) by one percent (100 basis points), compared with rates in effect at June 30, 2018, Northern Border's annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately nil million.

GTN's Unsecured Senior Notes, Northern Border's and Iroquois' Senior Notes, and all of Great Lakes' Notes represent fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates. Interest rate risk does not apply to Bison and North Baja, as they currently do not have any debt.

The Partnership and our pipeline systems use derivatives as part of our overall risk management policy to assist in managing exposures to market risk resulting from these activities within established policies and procedures. Derivative contracts used to manage market risk generally consist of the following:

- Swaps — contractual agreements between two parties to exchange streams of payments over time according to specified terms.
- Options — contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period.

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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. The Partnership hedged interest payments on the variable-rate 2013 Term Loan Facility with interest rate swaps maturing July 1, 2018, at a weighted average fixed interest rate of 2.31 percent. At June 30, 2018, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of \$15 million (both on a 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 \$1 million and a gain of \$6 million for the three and six months ended June 30, 2018, respectively (2017 — nil and gain of \$1 million). During the three and six months ended June 30, 2018, a gain of \$3 million was reclassified from other comprehensive income to net income (2017 — loss of \$1 million). For the three and six months ended June 30, 2018, the net realized gain related to the interest rate swaps was \$1 million and \$2 million, respectively, and was included in financial charges and other (2017 - nil).

The Partnership's \$500 million 2013 Term Loan is hedged using fixed interest rate swaps until July 1, 2018 at an average rate of 2.31 percent. During the fourth quarter of 2017, the Partnership implemented an interest rate hedging strategy that hedged the \$500 million 2013 Term Loan until its October 2, 2022 maturity using forward starting swaps at an average rate of 3.26 percent.

The Partnership has no master netting agreements; however, it has derivative contracts containing 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 June 30, 2018 (net asset of \$5 million as of December 31, 2017).

In anticipation of a debt refinancing in 2003, PNGTS entered into forward interest rate swap agreements to hedge the interest rate on its Senior Secured Notes due in 2018. These interest rate swaps were used to manage the impact of interest rate fluctuations and qualified as derivative financial instruments in accordance with ASC 815, *Derivatives and Hedging*. PNGTS settled its position with a payment of \$20.9 million to counterparties at the time of the refinancing and recorded the realized loss in accumulated other comprehensive income as of the termination date. The previously recorded loss was amortized against earnings over the life of the PNGTS Senior Secured Notes. On May 10, 2018, PNGTS paid the remaining principal balance of its 2003 Senior Secured Notes using its available cash and, as a result, our 61.71 percent proportionate share of the net unamortized loss on PNGTS included in other comprehensive income was all amortized against earnings (December 31, 2017 - \$1 million). For the three and six months ended June 30, 2018, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was \$1 million (2017 - \$1 million).

## OTHER RISKS

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' creditworthiness.

Our maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consists primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable as well as the fair value of derivative financial assets. We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At June 30, 2018, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At June 30, 2018 Anadarko Energy Services Company owed us approximately \$4 million which represented greater than 10 percent of our trade accounts receivable.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they become due. Our approach to managing liquidity risk is to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation.

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At June 30, 2018, the Partnership had a Senior Credit Facility of \$500 million maturing in 2021 and the outstanding balance on this facility was \$140 million. In addition, PNGTS has a \$125 million Revolving Credit Facility maturing in 2023 that has not been utilized at June 30, 2018 and Northern Border had a committed revolving bank line of \$200 million maturing in 2020 with \$15 million drawn at June 30, 2018. The Senior Credit Facility, the Northern Border \$200 million credit facility and the PNGTS \$125 million credit facility all have accordion features for additional capacity of \$500 million, \$100 million and \$50 million, respectively, subject to lender consent.

## Item 4. Controls and Procedures

### EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (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 period covered by this quarterly 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 Exchange Act, is (a) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (b) accumulated and communicated to the management of our General Partner, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

### Changes in Internal Control Over Financial Reporting

During the quarter ended June 30, 2018, there was no change in the Partnership's internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings

We are involved in various legal proceedings that arise in the ordinary course of business, as well as proceedings that we consider material under federal securities regulations. For additional information on other legal and environmental proceedings affecting the Partnership, please refer to Part 1 - Item 3 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017.

*Great Lakes v. Essar Steel Minnesota LLC, et al.* —

A description of this legal proceeding can be found in Note 16 within Item 1 "Financial Statements" of this Quarterly Report on Form 10-Q, and is incorporated herein by reference.

In addition to the above written matter, we and our pipeline systems are parties to lawsuits and governmental proceedings that arise in the ordinary course of our business.

## Item 1A. Risk Factors

The following updated risk factors should be read in conjunction with the risk factors disclosed in Part I, Item 1A “Risk Factors,” in our Annual Report on Form 10-K for the year ended December 31, 2017.

***We are exploring and evaluating potential mitigation strategies to the 2018 FERC Actions and other factors, including a possible reorganization that could result in us no longer being a master limited partnership.***

Given the effects of a number of factors, including the 2017 Tax Act and the 2018 FERC Actions, which resulted in an uncertainty of whether we could be restored as a viable funding lever for TransCanada, we are evaluating potential strategic alternatives for the Partnership, including whether remaining a master limited partnership is the appropriate structure for us.

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No decision has been made with respect to any mitigation strategies and we cannot assure you that the exploration of mitigation strategies will result in the identification or consummation of any transaction that allows our unitholders to realize an increase in the value of their common units or provide any guidance on the timing of such action, if any. We also cannot assure you that any mitigation strategy, if identified, evaluated and consummated, will provide greater value to our unitholders than that reflected in the current price of our common units.

We do not intend to comment regarding the evaluation of strategic alternatives until such time as the board of directors of our general partner has determined the outcome of the process or otherwise has deemed that disclosure is appropriate. As a consequence, perceived uncertainties related to our future may result in the loss of potential business opportunities and volatility in the market price of our common units.

***Our strategy of providing stable cash distributions on our common units by expanding our business may be significantly inhibited by the 2018 FERC Actions.***

TransCanada has historically sold certain FERC-regulated assets to the Partnership, subject to TransCanada’s funding needs and market conditions. Absent these dropdowns from TransCanada, our options for further growth could be significantly limited and there is uncertainty in whether we could be restored as a viable funding lever for TransCanada as a result of the 2018 FERC Actions. Also, market response to the 2018 FERC Actions has increased the relative cost of equity that the Partnership would incur to partially fund acquisitions or expansions in the future. Further deterioration of financial conditions could also raise the borrowing costs of the Partnership.

If we cannot successfully finance and complete expansion projects or make and integrate acquisitions that are accretive and the earnings of our existing pipeline systems are materially and adversely impacted as a result of the 2018 FERC Actions, we will not be able to maintain historical levels of cash flow and distributions. For example, if we are unable to replace revenues from Bison once its contracts expire in January of 2021 or we are unable to replace cash flow that may be reduced through future rate proceedings, we could be required to take additional proactive measures, including further reductions in distributions from the current level of \$0.65 per common unit, to facilitate repayments of debt as may be needed to maintain compliance with financial covenants, in addition to taking other significant strategic actions.

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

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

Due to the uncertainties surrounding the 2018 FERC Actions, implementation of our regulatory strategy to minimize any negative impact on our future operating performance and cash flows will take time. Moreover, we believe that future results of operations, cash flows and financial position of the Partnership could be materially and negatively impacted once our pipelines’ rates are ultimately adjusted following these decisions. Our assumptions around the potential outcomes of the 2018 FERC Actions could be incorrect such that cash available for distribution in the future would be lower than anticipated, which could necessitate further action beyond our immediate responses described under Item 2 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of this Quarterly Report on Form 10-Q.

***Future events, such as the outcome of the 2018 FERC Actions, could negatively impact our estimates of fair value of our pipeline systems and equity investments, necessitating recognition of impairment.***

We consider the carrying value of our assets, including goodwill and our equity method investments, whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments that we account for under the equity method, the impairment test requires us to consider whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Our assumptions related to the estimated fair value of our remaining carrying value of each of our pipeline systems could be negatively impacted by near and long-term conditions including:

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- future regulatory rate action or settlement,
- valuation of assets in future transactions,

- changes in customer demand for pipeline capacity and services,
- changes in North American natural gas production in the major producing basins,
- changes in natural gas prices and natural gas storage market conditions, and
- changes in other long-term strategic objectives.

There is a risk that adverse changes in these key assumptions as a result of the 2018 FERC Actions or other circumstances could result in future impairment of the carrying value of our pipeline systems.

The development of fair value estimates requires significant judgment including estimates of future cash flows, which are dependent on internal forecasts, estimates of the long-term rate of growth, estimates of the useful life over which cash flows will occur, and determination of weighted average cost of capital. Following the 2018 FERC Actions, many of these elements will be revisited as individual rate proceedings clarify specific applications of the new policies and rules. At this time, we are unable to precisely calculate the impact on fair value, if any, due to uncertainties surrounding the 2018 FERC Actions.

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**Item 6. Exhibits**

Exhibits designated by an asterisk (\*) are filed herewith and those designated with asterisks (\*\*) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

- 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 [Option Agreement Relating to Partnership Interest in Iroquois Gas Transmission System, L.P. by and between TransCanada Iroquois Ltd. and TC Pipelines Intermediate Limited Partnership as dated as of May 3, 2017 \(Incorporated by reference from Exhibit 2.2 to TC PipeLines, LP's Form 8-K filed May 3, 2017\).](#)
- 2.3 [Agreement for Purchase and Sale of Partnership Interest in Portland Natural Gas Transmission System, by and between TCPL Portland Inc., as Seller and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 3, 2017 \(Incorporated by reference from Exhibit 2.3 to TC PipeLines, LP's Form 8-K filed May 3, 2017\).](#)
- 3.1 [Third Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated April 1, 2015 \(Incorporated by reference from Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed April 1, 2015\).](#)
- 3.1.1 [Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated December 13, 2017 \(incorporated by reference from Exhibit 3.1 to TC PipeLines, LP's Form 8-K filed December 15, 2017\).](#)
- 3.2 [Certificate of Limited Partnership of TC PipeLines, LP \(Incorporated by reference to Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, filed on December 30, 1998\).](#)
- 4.1 [Indenture, dated as of June 17, 2011, between the Partnership and The Bank of New York Mellon, as trustee \(Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed on June 17, 2011\).](#)
- 4.2 [Supplemental Indenture, dated as of June 17, 2011 relating to the issuance of \\$350,000,000 aggregate principal amount of 4.65% Senior Notes due 2021 \(Incorporated by reference to Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed on June 17, 2011\).](#)
- 4.3 [Specimen of 4.65% Senior Notes due 2021 \(Incorporated by reference to Exhibit A to the Supplemental Indenture filed as Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed on June 17, 2011\).](#)
- 4.4 [Form of indenture for senior debt securities \(Incorporated by reference to Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed on June 14, 2011\).](#)
- 4.5 [Second Supplemental Indenture, dated March 13, 2015, between TC PipeLines, LP and The Bank of New York Mellon \(incorporated by reference from Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed March 13, 2015\).](#)
- 4.6 [Third Supplemental Indenture, dated as of May 25, 2017, relating to the issuance of \\$500,000,000 aggregate principal amount of 3.900% Senior Notes due 2027 \(Incorporated by reference from Exhibit 4.2 to TC PipeLines, LP's Form 8-K filed May 25, 2017\).](#)
- 4.7 [Portland Natural Gas Transmission System Senior Secured Note Purchase Agreement dated as of April 10, 2003 \(Incorporated by reference from Exhibit 4.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)
- 4.8 [Iroquois Gas Transmission, L.P. Senior Note Purchase Agreement dated as of May 13, 2009 \(Incorporated by reference from Exhibit 4.2 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)
- 4.9 [Iroquois Gas Transmission, L.P. Senior Note Purchase Agreement dated as of April 27, 2010 \(Incorporated by reference from Exhibit 4.3 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)

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- 4.10 [Indenture dated as of May 30, 2000, between Iroquois Gas Transmission System, L.P. and The Chase Manhattan Bank \(Incorporated by reference from Exhibit 4.4 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)
- 4.10.1 [Second Supplemental Indenture dated as of August 13, 2002, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank \(formerly known as The Chase Manhattan Bank\) \(Incorporated by reference from Exhibit 4.4.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)
- 4.11 [Credit Agreement dated as of June 26, 2008, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent \(Incorporated by reference from Exhibit 4.5 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)
- 4.11.1 [Amendment No. 1 to Credit Agreement dated as of June 25, 2009, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent for the lenders \(Incorporated by reference from Exhibit 4.5.1 to TC PipeLines, LP's Form 10-Q filed August 3, 2017\).](#)
- 10.1\* [Transportation Service Agreement FT19214 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company,](#)



[effective date April 16, 2018.](#)

10.2\* [Transportation Service Agreement FT19215 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 16, 2018.](#)

10.3\* [Amended Precedent Agreement by and between Portland Natural Gas Transmission System and TransCanada PipeLines Limited](#)

10.4\* [Amended Financial Assurances Agreement by and between Portland Natural Gas Transmission System and TransCanada PipeLines Limited](#)

31.1\* [Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)

31.2\* [Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)

32.1\*\* [Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.](#)

32.2\*\* [Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.](#)

101.INS XBRL Instance Document.

101.SCH XBRL Taxonomy Extension Schema Document.

101.CAL XBRL Taxonomy Extension Calculation Linkbase Document.

101.DEF XBRL Taxonomy Definition Linkbase Document.

101.LAB XBRL Taxonomy Extension Label Linkbase Document.

101.PRE XBRL Taxonomy Extension Presentation Linkbase Document.

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### 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 2<sup>nd</sup> day of August 2018.

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)



**TRANSPORTATION SERVICE AGREEMENT**  
 Contract Identification FT19214

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR PIPELINE COMPANY (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. **EFFECTIVE DATE:** April 16, 2018
2. **CONTRACT IDENTIFICATION:** FT19214
3. **RATE SCHEDULE:** FT
4. **SHIPPER TYPE:** Interstate PI
5. **STATE/PROVINCE OF INCORPORATION:** Delaware
6. **TERM:** November 01, 2021 to October 31, 2036
7. **EFFECT ON PREVIOUS CONTRACTS:**  
 This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): N/A
8. **MAXIMUM DAILY QUANTITY (Dth/Day):** 160,000  
 Please see Appendix A for further detail.
9. **RATES:**  
 Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than the maximum shall be set forth in this Paragraph 9 and/or on Appendix B hereto.

10. **POINTS OF RECEIPT AND DELIVERY:**  
The primary receipt and delivery points are set forth on Appendix A.
11. **RELEASED CAPACITY:**  
N/A
12. **INCORPORATION OF TARIFF INTO AGREEMENT:**  
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.
13. **MISCELLANEOUS:**  
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.
- Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.
14. **OTHER PROVISIONS:**  
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.
- Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.
- Transporter and Shipper agree that, pursuant to Section 6.2.1(h) of the General Terms and Conditions, this Agreement is subject to a Reduction Option as herein described:
- Upon written notice to Transporter, Shipper shall have a Reduction Option:
- 1) At any time on or before April 1, 2019 for any reason, and
  - 2) Any time before April 1, 2021, to the extent necessary due to the failure or inability to secure all applicable federal, state, and local governmental and regulatory approval(s) related to an anticipated expansion project.
- If Shipper invokes this Reduction Option, it may reduce all or a portion of the contractual MDQ associated with this Agreement, and/or terminate this Agreement earlier than 10/31/2036.

15. NOTICES AND COMMUNICATIONS:

All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or fax, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or fax, or other means similarly agreed to:

ADMINISTRATIVE MATTERS

Great Lakes Gas Transmission Limited Partnership  
Commercial Services  
700 Louisiana St., Suite 700  
Houston, TX 77002-2700

ANR PIPELINE COMPANY  
700 Louisiana St., Suite 700  
Houston, TX 77002-2700  
Attn:

AGREED TO BY:

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP  
By: Great Lakes Gas Transmission Company

ANR PIPELINE COMPANY

By: Kay Dennison  
Kay Dennison  
Title: Director, Transportation Accounting and Contracts

By: [Signature]  
Signature  
Brandin Anderson  
Please Print  
Title: Vice President  
Please Print

Handwritten notes: #4312, CW 4-25-18

APPENDIX A  
Contract Identification FT19214

Date: April 16, 2018  
Supersedes Appendix Dated: Not Applicable

Shipper: ANR PIPELINE COMPANY

Maximum Daily Quantity (Dth/Day) per Location:

<u>Begin Date</u>	<u>End Date</u>	<u>Point(s) of Primary Receipt</u>	<u>Point(s) of Primary Delivery</u>	<u>MDO</u>	<u>Maximum Allowable Operating Pressure (MAOP)</u>
11/01/2021	10/31/2036	EMERSON		160,000	974
11/01/2021	10/31/2036		FORTUNE LAKE	160,000	974



**TRANSPORTATION SERVICE AGREEMENT**  
 Contract Identification FT19215

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and ANR PIPELINE COMPANY (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. **EFFECTIVE DATE:** April 16, 2018
2. **CONTRACT IDENTIFICATION:** FT19215
3. **RATE SCHEDULE:** FT
4. **SHIPPER TYPE:** Interstate PI
5. **STATE/PROVINCE OF INCORPORATION:** Delaware
6. **TERM:** November 01, 2021 to October 31, 2036
7. **EFFECT ON PREVIOUS CONTRACTS:**  
 This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): N/A
8. **MAXIMUM DAILY QUANTITY (Dth/Day):** 800,000  
 Please see Appendix A for further detail.
9. **RATES:**  
 Unless Shipper and Transporter have agreed to a rate other than the maximum rate, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Rate other than the maximum shall be set forth in this Paragraph 9 and/or on Appendix B hereto.

10. **POINTS OF RECEIPT AND DELIVERY:**  
The primary receipt and delivery points are set forth on Appendix A.
11. **RELEASED CAPACITY:**  
N/A
12. **INCORPORATION OF TARIFF INTO AGREEMENT:**  
This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Third Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.
13. **MISCELLANEOUS:**  
No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.
- Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.
14. **OTHER PROVISIONS:**  
It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.
- Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.
- Transporter and Shipper agree that, pursuant to Section 6.2.1(h) of the General Terms and Conditions, this Agreement is subject to a Reduction Option as herein described:
- Upon written notice to Transporter, Shipper shall have a Reduction Option:
- 1) At any time on or before April 1, 2019 for any reason, and
  - 2) Any time before April 1, 2021, to the extent necessary due to the failure or inability to secure all applicable federal, state, and local governmental and regulatory approval(s) related to an anticipated expansion project.
- If Shipper invokes this Reduction Option, it may reduce all or a portion of the contractual MDQ associated with this Agreement, and/or terminate this Agreement earlier than 10/31/2036.

15. NOTICES AND COMMUNICATIONS:

All notices and communications with respect to this Agreement shall be in writing by mail, e-mail, or fax, or other means as agreed to by the parties, and sent to the addresses stated below or to any other such address(es) as may be designated in writing by mail, e-mail, or fax, or other means similarly agreed to:

**ADMINISTRATIVE MATTERS**  
Great Lakes Gas Transmission Limited  
Partnership  
Commercial Services  
700 Louisiana St., Suite 700  
Houston, TX 77002-2700

ANR PIPELINE COMPANY  
700 Louisiana St., Suite 700  
Houston, TX 77002-2700  
Attn:

AGREED TO BY:

**GREAT LAKES GAS TRANSMISSION  
LIMITED PARTNERSHIP**  
By: Great Lakes Gas Transmission Company

ANR PIPELINE COMPANY

By: Kay Dennison  
Kay Dennison  
Title: Director, Transportation Accounting and  
Contracts

By: [Signature]  
Signature  
Brandon Anderson  
Please Print  
Title: Vice President  
Please Print

AD  
4/25/18  
CW  
4-25-18



APPENDIX A  
Contract Identification FT19215

Date: April 16, 2018  
Supersedes Appendix Dated: Not Applicable

Shipper: ANR PIPELINE COMPANY

Maximum Daily Quantity (Dth/Day) per Location:

<u>Begin Date</u>	<u>End Date</u>	<u>Point(s) of Primary Receipt</u>	<u>Point(s) of Primary Delivery</u>	<u>M/DQ</u>	<u>Maximum Allowable Operating Pressure (MAOP)</u>
11/01/2021	10/31/2036	EMERSON		800,000	974
11/01/2021	10/31/2036		FARWELL	800,000	974

**AMENDING AGREEMENT**

This Amending Agreement is made as of the 26<sup>th</sup> day of June 2018.

BETWEEN:

**TRANSCANADA PIPELINES LIMITED**  
a Canadian corporation  
("TransCanada")

- and -

**PORTLAND NATURAL GAS TRANSMISSION  
SYSTEM**  
a Maine General Partnership  
("Shipper")

WHEREAS TransCanada and Shipper are parties to a Precedent Agreement dated October 31, 2017 (the "Agreement"); and

WHEREAS TransCanada and Shipper wish to amend the Agreement by increasing the Phase III quantity by 10,551 GJ/d from 182,751 GJ/d to 193,302 GJ/d;

NOW THEREFORE TransCanada and Shipper agree as follows:

**ARTICLE 1**  
**INCORPORATION, DEFINITIONS AND EFFECTIVE DATE**

- 1.1 This Amending Agreement and the provisions hereof are supplemental to the Agreement, and are to form part of and have the same effect as though incorporated in the Agreement.
- 1.2 Unless otherwise defined in this Amending Agreement, all capitalized terms contained in this Amending Agreement which are defined in the Agreement shall for all purposes hereof have the meaning given to them in the Agreement unless the context otherwise specifies or requires.
- 1.3 This Amending Agreement is effective as of the date first written above.

**ARTICLE 2**  
**AMENDMENTS TO THE AGREEMENT**

- 2.1 The Agreement is amended as follows:
  - (a) by deleting the third recital in its entirety and replacing it with the following:

WHEREAS pursuant to a new capacity open season which closed on September 21, 2017 (the "New Capacity Open Season"), Shipper requested TransCanada to transport up to 184,862 GJ/d of natural gas from the Union Dawn receipt point and 8,440 GJ/d of natural gas from the Union Parkway Belt receipt point (collectively, the "Receipt Point") to, in both cases, the East Hereford delivery point (into the PNGTS system) (the "Delivery Point") for delivery for the account of Shipper in three phases (such three phases are sometimes referred to individually as a "Phase" and collectively defined as the "Phases"), with each Phase having its own specified in-service date (for each Phase, its "In-Service Date"), as further described below:

- the first Phase shall have an In-Service Date of November 1, 2018 or as soon as possible thereafter to transport 39,663 GJ/day from the Union Dawn Receipt Point and 2,651 GJ/day from the Union Parkway Belt Receipt Point for an aggregate of 42,314 GJ/day, for a term of 22 years ("Phase I");
- the second Phase shall have an In-Service Date of November 1, 2019 or as soon as possible thereafter to transport 159,960 GJ/day from the Union Dawn Receipt Point and 7,481 GJ/day from the Union Parkway Belt Receipt Point for an aggregate of 167,441 GJ/day, for a term of 21 years ("Phase II"); and
- the third phase shall have an In-Service Date of November 1, 2020 or as soon as possible thereafter to transport 184,862 GJ/day from the Union Dawn Receipt Point and 8,440 GJ/day from the Union Parkway Belt Receipt Point for an aggregate of 193,302 GJ/day, for a term of 20 years ("Phase III").

All of the above collectively defined as the "Requested Service".

### **ARTICLE 3** **MISCELLANEOUS**

- 3.1 This Amending Agreement supercedes all negotiations, discussions and undertakings between the parties in relation to the subject matter hereof.
- 3.2 The Agreement shall remain in full force and effect as amended by this Amending Agreement and is hereby ratified and confirmed as amended.
- 3.3 This Amending Agreement may be executed by the parties in separate counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute one and the same instrument. A facsimile or other electronic copy of this Amending Agreement containing the signature of a party will be deemed to be an originally signed document.


*[Execution page follows]*

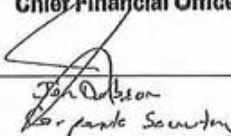
IN WITNESS WHEREOF the parties to this Amending Agreement have caused it to be executed by their duly authorized officers as of the day and year first written above.

PORTLAND NATURAL GAS  
TRANSMISSION SYSTEM, BY ITS  
OPERATOR, PNGTS OPERATING  
CO., LLC




TRANSCANADA PIPELINES LIMITED

By:   
Name: **Nathaniel A. Brown**  
Title: **Chief Financial Officer**

By:   
Name: Karl Johansson  
Title: Executive Vice President, Natural Gas Pipe

By:   
Name: Jon Johnson  
Title: Corporate Secretary

By:   
Name: **Don Bell**  
Title: **Director, Commercial East**

Contract Content	
Manager, Customer Service	
Content Review	
Legal Review	

**AMENDING AGREEMENT**

This Amending Agreement is made as of the 26<sup>th</sup> day of June 2018.

BETWEEN:

**TRANSCANADA PIPELINES LIMITED**  
a Canadian corporation  
("TransCanada")

- and -

**PORTLAND NATURAL GAS TRANSMISSION  
SYSTEM**  
a Maine General Partnership  
("Shipper")

WHEREAS TransCanada and Shipper are parties to a Financial Assurances Agreement dated November 30, 2017 (the "Agreement"); and

WHEREAS TransCanada and Shipper wish to amend the Agreement by increasing the Phase III quantity by 10,551 GJ/d from 182,751 GJ/d to 193,302 GJ/d;

NOW THEREFORE TransCanada and Shipper agree as follows:

**ARTICLE 1****INCORPORATION, DEFINITIONS AND EFFECTIVE DATE**

- 1.1 This Amending Agreement and the provisions hereof are supplemental to the Agreement, and are to form part of and have the same effect as though incorporated in the Agreement.
- 1.2 Unless otherwise defined in this Amending Agreement, all capitalized terms contained in this Amending Agreement which are defined in the Agreement shall for all purposes hereof have the meaning given to them in the Agreement unless the context otherwise specifies or requires.
- 1.3 This Amending Agreement is effective as of the date first written above.

**ARTICLE 2****AMENDMENTS TO THE AGREEMENT**

- 2.1 The Agreement is amended as follows:
  - (a) by deleting the second and third recitals in its entirety and replacing it with the following:

WHEREAS, each Contract, upon execution, will be for gas transportation and related services where TransCanada determined it must construct facilities in order to provide such service (the "Expansion Capacity Service") and would provide for TransCanada to transport for the account of Shipper up to 184,862 GJ/d of natural gas from the Union Dawn Receipt Point and 8,440 GJ/d of natural gas from the Union Parkway Belt Receipt Point to, in both cases, the East Hereford, Quebec Delivery Point (into the PNGTS system); and

WHEREAS, the Expansion Capacity Service is anticipated to be on a three phased-basis commencing (for each phase, its "In-Service Date") as follows (such three phases are sometimes referred to individually as a "Phase"):

- Commencing on the 1st of November 2018 or as soon as possible thereafter, 39,663 GJ/day from the Union Dawn Receipt Point and 2,651 GJ/day from the Parkway Receipt Point for an aggregate of 42,314 GJ/day, for a term of 22 years ("Phase I");
- Commencing on the 1st of November 2019 or as soon as possible thereafter, 159,960 GJ/day from the Union Dawn Receipt Point and 7,481 GJ/day from the Union Parkway Belt Receipt Point for an aggregate of 167,441 GJ/day, for a term of 21 years ("Phase II"); and
- Commencing on the 1st of November 2020 or as soon as possible thereafter, 184,862 GJ/day from the Union Dawn Receipt Point and 8,440 GJ/day from the Union Parkway Belt Receipt Point for an aggregate of 193,302 GJ/day, for a term of 20 years (transportation services commencing at this time shall be referred to as "Phase III" of the Expansion Capacity Service); and

**ARTICLE 3**  
**MISCELLANEOUS**

- 3.1 This Amending Agreement supercedes all negotiations, discussions and undertakings between the parties in relation to the subject matter hereof.
- 3.2 The Agreement shall remain in full force and effect as amended by this Amending Agreement and is hereby ratified and confirmed as amended.
- 3.3 This Amending Agreement may be executed by the parties in separate counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute one and the same instrument. A facsimile or other electronic copy of this Amending Agreement containing the signature of a party will be deemed to be an originally signed document.


*[Execution page follows]*

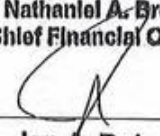
IN WITNESS WHEREOF the parties to this Amending Agreement have caused it to be executed by their duly authorized officers as of the day and year first written above.

PORTLAND NATURAL GAS  
TRANSMISSION SYSTEM, BY ITS  
OPERATOR, PNGTS OPERATING  
CO., LLC

TRANSCANADA PIPELINES LIMITED

By:  ZB  
Name: **Nathaniel A. Brown**  
Title: **Chief Financial Officer**

By:   
Name: **Karl Johannson**  
Title: **Executive Vice President, Natural Gas Pipelin**

By:  ZB  
Name: **Jon A. Dobson**  
Title: **Corporate Secretary**

By:   
Name: **Don Bell**  
Title: **Director, Commercial East**

Contract Content	
Manager, Customer Service	ZB
Content Review	AC
Legal Review	AD

CERTIFICATION OF  
PRINCIPAL EXECUTIVE OFFICER

I, Nathaniel A. Brown, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TC PipeLines, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: August 2, 2018  
/s/ Nathaniel A. Brown  
\_\_\_\_\_  
Nathaniel A. Brown

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

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CERTIFICATION OF  
PRINCIPAL FINANCIAL OFFICER

I, William C. Morris, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TC PipeLines, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: August 2, 2018  
/s/ William C. Morris  
\_\_\_\_\_  
William C. Morris

Principal Financial Officer, Vice President and Treasurer  
TC PipeLines GP, Inc., as General Partner of  
TC PipeLines, LP

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**CERTIFICATION OF  
PRINCIPAL EXECUTIVE OFFICER**

I, Nathaniel A. Brown, Principal Executive Officer and President of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Quarterly Report on Form 10-Q for the period ended June 30, 2018 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

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

Dated: August 2, 2018  
/s/ Nathaniel A. Brown  
\_\_\_\_\_  
Nathaniel A. Brown

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

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**CERTIFICATION OF  
PRINCIPAL FINANCIAL OFFICER**

I, William C. Morris, Principal Financial Officer, Vice-President and Treasurer of TC PipeLines GP, Inc., the General Partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge, in connection with the Partnership's Quarterly Report on Form 10-Q for the period ended June 30, 2018 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

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

Dated: August 2, 2018  
/s/ William C. Morris  
\_\_\_\_\_  
William C Morris

Principal Financial Officer, Vice President and Treasurer  
TC PipeLines GP, Inc., as General Partner of  
TC PipeLines, LP

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