TC PIPELINES LP
Form 10-Q
August 03, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

or

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

For the transition period from to

Commission File Number: 001-35358

TC PipeLines, LP

(Exact name of registrant as specified in its charter)

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

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

Yes x No o

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 x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o
Emerging growth company o	

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

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

Yes o No x

As of August 1, 2017, there were 69,388,212 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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DEFINITIONS

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 dated July 1, 2013
2015 GTN Acquisition	Partnership s acquisition of the remaining 30 percent interest in GTN on April 1, 2015
2015 Term Loan Facility	TC PipeLines, LP s term loan credit facility under a term loan agreement dated September 30, 2015
2016 PNGTS Acquisition	Partnership s acquisition of a 49.9 percent interest in PNGTS, effective January 1, 2016
2017 Acquisition	Partnership s acquisition of the additional 11.81 percent interest in PNGTS and 49.34 percent in Iroquois on June 1, 2017
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
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
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, and PNGTS
Partnership	TC PipeLines, LP including its subsidiaries, as applicable
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PNGTS	Portland Natural Gas Transmission System
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines, LP s senior facility under revolving credit agreement as amended and restated, dated November 10, 2016
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 effective June 1, 2017, 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 a meaning. The absence of these words, however, does not mean that the statements are not forward-looking. These statements are based on management s beliefs and assumptions and on currently available information and include, but are not limited to, statements regarding anticipated financial performance, future capital expenditures, liquidity, market or competitive conditions, regulations, organic or strategic growth opportunities, contract renewals and ability to market open capacity, business prospects, outcome of regulatory proceedings and cash distributions to unitholders.

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

- the ability of our pipeline systems to sell available capacity on favorable terms and renew expiring contracts which are affected by, among other factors:
- demand for natural gas;
- changes in relative cost structures and production levels of natural gas producing basins;
- natural gas prices and regional differences;
- weather conditions;
- availability and location of natural gas supplies in Canada and the United States (U.S.) in relation to our pipeline systems;
- competition from other pipeline systems;
- natural gas storage levels; and
- rates and terms of service;
- the performance by the shippers of their contractual obligations on our pipeline systems;
- the outcome and frequency of rate proceedings or settlement negotiations on our pipeline systems;

- changes in the taxation of master limited partnerships by state or federal governments such as final adoption of proposed regulations narrowing the sources of income qualifying for partnership tax treatment or the elimination of pass-through taxation or tax deferred distributions;

- increases in operational or compliance costs resulting from changes in laws and governmental regulations affecting our pipeline systems, particularly regulations issued by the Federal Energy Regulatory Commission (FERC), the U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT);

- the impact of 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 and us;

- the impact of any impairment charges;

- cybersecurity threats, acts of terrorism and related disruptions;

the impact of new accounting pronouncements;

operating hazards, casualty losses and other matters beyond our control; and

- the level our indebtedness, including the indebtedness of our pipeline systems, and the availability of capital.

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 I, Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2016 as filed with the SEC on February 28, 2017. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. All forward-looking statements are made only as of the

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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, 2017	Three months ended June 30, 2016 (a)	Six months ended June 30, 2017	Six months ended June 30, 2016 (a)
Transmission revenues	**101**	101	**213**	212
Equity earnings *(Note 4)*	**24**	20	**60**	53
Operation and maintenance expenses	**(17)**	(14)	**(31)**	(25)
Property taxes	**(7)**	(7)	**(14)**	(14)
General and administrative	**(2)**	(2)	**(4)**	(4)
Depreciation	**(25)**	(24)	**(49)**	(48)
Financial charges and other *(Note 14)*	**(19)**	(17)	**(36)**	(35)
Net income before taxes	**55**	57	**139**	139
Income taxes *(Note 18)*			**(1)**	(1)
Net income	**55**	57	**138**	138
Net income attributable to non-controlling interests		2	**6**	8
Net income attributable to controlling interests	**55**	55	**132**	130
Net income attributable to controlling interest allocation *(Note 8)*				
Common units	**50**	50	**122**	121
General Partner	**5**	3	**8**	5
TransCanada and its subsidiaries		2	**2**	4
	55	55	**132**	130
Net income per common unit *(Note 8)* basic and diluted	**$ 0.73**	$ 0.76(b)	**$ 1.78**	$ 1.86(b)
Weighted average common units outstanding basic and diluted *(millions)*	**68.9**	65.5	**68.6**	64.9
Common units outstanding, end of period *(millions)*	**69.0**	65.9	**69.0**	65.9

(a) Recast to consolidate PNGTS for all periods presented (Refer to Notes 2 and 6).

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

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

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TC PIPELINES, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited) (millions of dollars)	Three months ended June 30, 2017	Three months ended June 30, 2016(a)	Six months ended June 30, 2017	Six months ended June 30, 2016(a)
Net income	**55**	57	**138**	138
Other comprehensive income				
Change in fair value of cash flow hedges *(Note 12)*		(1)	**1**	(3)
Amortization of realized loss on derivative financial instruments *(Note 12)*	**1**	1	**1**	1
Reclassification to net income of gains and losses on cash flow hedges *(Note 12)*	**(1)**		**(1)**	
Comprehensive income	**55**	57	**139**	136
Comprehensive income attributable to non-controlling interests (a)		2	**6**	8
Comprehensive income attributable to controlling interests	**55**	55	**133**	128

(a) Recast to consolidate PNGTS for all periods presented (Refer to Notes 2 and 6).

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, 2017	December 31, 2016 (a)
ASSETS		
Current Assets		
Cash and cash equivalents	**51**	64
Accounts receivable and other *(Note 13)*	**37**	47
Inventories	**7**	7
Other	**5**	7
	100	125
Equity investments *(Note 4)*	**1,138**	918
Plant, property and equipment		
(Net of $1,135 accumulated depreciation; 2016 - $1,088)	**2,148**	2,180
Goodwill	**130**	130
Other assets		1
	3,516	3,354
LIABILITIES AND PARTNERS EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**27**	29
Accounts payable to affiliates *(Note 6 and 11)*	**35**	8
Distribution payable		3
Accrued interest	**11**	10
Current portion of long-term debt *(Note 5)*	**57**	52
	130	102
Long-term debt, net *(Note 5)*	**2,333**	1,859
Deferred state income taxes *(Note 18)*	**10**	10
Other liabilities	**28**	28
	2,501	1,999
Common units subject to rescission *(Note 7)*		83
Partners Equity		
Common units	**795**	1,002
Class B units *(Note 7)*	**95**	117
General partner	**25**	27
Accumulated other comprehensive loss	**(1)**	(2)
Controlling interests	**914**	1,144
Non-controlling interests	**101**	97
Equity of former parent of PNGTS		31
	1,015	1,272
	3,516	3,354
Contingencies *(Note 15)*		
Variable Interest Entities *(Note 17)*		
Subsequent Events *(Note 19)*		

(a) Recast to consolidate PNGTS for all periods presented (Refer to Notes 2 and 6).

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, 2017	2016 (a)
Cash Generated From Operations		
Net income	**138**	138
Depreciation	**49**	48
Amortization of debt issue costs reported as interest expense	**1**	1
Amortization of realized loss on derivative instrument	**1**	1
Accrual for costs related to the 2017 Acquisition	**1**	
Deferred state income tax recovery *(Note 18)*		(7)
Equity earnings from equity investments *(Notes 3 and 4)*	**(60)**	(53)
Distributions received from operating activities of equity investments *(Note 3)*	**68**	95
Change in operating working capital *(Note 10)*	**7**	12
	205	235
Investing Activities		
Investment in Great Lakes	**(4)**	(4)
Acquisition of a 49.9 percent interest in PNGTS		(193)
Acquisition of a 49.34 percent in Iroquois and an additional 11.81 percent in PNGTS (Note 6)	**(605)**	
Capital expenditures	**(16)**	(18)
Other		2
	(625)	(213)
Financing Activities		
Distributions paid *(Note 9)*	**(135)**	(119)
Distributions paid to Class B units *(Note 7)*	**(22)**	(12)
Distributions paid to non-controlling interests	**(5)**	(9)
Distributions paid to former parent of PNGTS	**(1)**	(8)
Common unit issuance, net *(Note 7)*	**92**	
Common unit issuance subject to rescission, net *(Note 7)*		83
Long-term debt issued, net of discount *(Note 5)*	**607**	205
Long-term debt repaid *(Note 5)*	**(128)**	(165)
Debt issuance costs	**(1)**	
	407	(25)
Decrease in cash and cash equivalents	**(13)**	(3)
Cash and cash equivalents, beginning of period	**64**	55
Cash and cash equivalents, end of period	**51**	52

(a) Recast to consolidate PNGTS for all periods presented (Refer to Notes 2 and 6).

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 Common Units millions of units	millions of dollars	Class B Units millions of units	millions of dollars	General Partner millions of dollars	Accumulated Other Comprehensive Loss (a) (b) millions of dollars	Non-Controlling Interest(b) millions of dollars	Equity of former parent of PNGTS(b) millions of dollars	Total Equity(b) millions of dollars
Partners Equity at December 31, 2016	67.4	1,002	1.9	117	27	(2)	97	31	1,272
Net income (b)		122			8		6	2	138
Other comprehensive income						1			1
ATM equity issuances, net *(Note 7)*	1.6	90			2				92
Reclassification of common units no longer subject to rescission *(Note 7)*		81			2				83
Acquisition of interest in PNGTS and Iroquois (*Note 6)*		(371)			(8)			(32)	(411)
Distributions (b)		(129)		(22)	(6)		(2)	(1)	(160)
Partners Equity at June 30, 2017	**69.0**	**795**	**1.9**	**95**	**25**	**(1)**	**101**		**1,015**

(a) Losses related to cash flow hedges reported in Accumulated Other Comprehensive Loss and expected to be reclassified to Net Income in the next 12 months are estimated to be $2 million. These estimates assume constant interest rates over time; however, the amounts reclassified will vary based on actual value of interest rates at the date of settlement.

(b) Recast to consolidate PNGTS for all periods presented. See Notes 2 and 6.

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, 2017 and 2016 are not necessarily indicative of the results that may be expected for 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, 2016 included as exhibit 99.2 in our Current Report on Form 8-K dated August 3, 2017. 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 audited financial statements and notes thereto for the year ended December 31, 2016 included as exhibit 99.2 in our Current Report on Form 8-K dated August 3, 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.

On June 1, 2017, the Partnership acquired from a subsidiary of TransCanada an additional 11.81 percent interest in PNGTS, resulting in the Partnership owning 61.71 percent in PNGTS (Refer to Note 6-Acquisitions). As a result of the Partnership owning 61.71 percent of PNGTS, the Partnership s historical financial information has been recast, except net income (loss) per common unit, to consolidate PNGTS for all the periods presented in the Partnership s consolidated financial statements. Additionally, this acquisition was accounted for as transaction between entities under common control, similar to pooling of interests, whereby the assets and liabilities of PNGTS were recorded at TransCanada s carrying value.

Also, on June 1, 2017, the Partnership acquired from subsidiaries of TransCanada a 49.34 percent interest in Iroquois Gas Transmission, L.P. (Iroquois) (Refer to Note 6-Acquisitions). Accordingly, this transaction was accounted for as a transaction between entities under common control, similar to pooling of interest, whereby the equity investment in Iroquois was recorded at TransCanada s carrying value and was accounted for prospectively.

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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

Retrospective application of ASU No 2016-15 Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued an amendment of previously issued guidance, which intends to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The new guidance is effective January 1, 2018, however, as early adoption is permitted, the Partnership elected to retrospectively apply this guidance effective December 31, 2016. The Partnership has elected to classify distributions received from equity method investees using the nature of distributions approach as it is more representative of the nature of the underlying activities of the investees that generated the distributions. As a result, certain comparative period distributions received from equity method investees, amounting to $42 million for the six months ended June 30, 2016, have been reclassified from investing activities to cash generated from operations in the consolidated statement of cash flows.

Effective January 1, 2017

Inventory

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

Equity method and joint ventures

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

Consolidation

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

Future accounting changes

Revenue from contracts with customers

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

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anticipates adopting the standard using the modified retrospective approach with the cumulative-effect of initially applying the guidance recognized at the date of adoption, subject to allowable and elected practical expedients.

The Partnership has identified all existing customer contracts that are within the scope of the new guidance and is in the process of analyzing individual contracts or groups of contracts on a segmented basis to identify any significant changes in how revenues are recognized as a result of implementing the new standard. While the Partnership has not identified any material differences in the amount and timing of revenue recognition for the contracts that have been analyzed to date, the evaluation is not complete and the Partnership has not concluded on the overall impact of adopting the new guidance. The Partnership continues its segmented contract analysis to obtain the information necessary to quantify, the cumulative-effect adjustment, if any, on prior period revenues. The Partnership also continues to address any system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

Leases

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

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

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. Early adoption is permitted. The Partnership is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

NOTE 4 EQUITY INVESTMENTS

The Partnership has equity interests in Northern Border, Great Lakes and effective June 1, 2017, Iroquois. The pipeline systems owned by these entities are regulated by FERC. The pipeline systems of Northern Border and Great Lakes are operated by subsidiaries of TransCanada. The Iroquois pipeline system is operated by Iroquois Pipeline Operating Company, a wholly owned subsidiary of Iroquois. The Partnership uses the equity method of accounting for its interests in its equity investees. The Partnership s equity investments are held through our ILPs that are considered to be variable interest entities (VIEs) (refer to Note 17).

	Ownership	Equity Earnings				Equity Investments	
	Interest at	Three months		Six Months			
(unaudited)	June 30,	ended June 30,		ended June 30,		June 30,	December 31,
(millions of dollars)	2017	2017	2016(b)	2017	2016(b)	2017	2016(b)
Northern Border (a)	50%	**15**	16	**34**	34	**437**	444
Great Lakes	46.45%	**6**	4	**23**	19	**475**	474
Iroquois	49.34%	**3**		**3**		**226**	
		24	20	**60**	53	**1,138**	918

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

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(b) Recast to eliminate equity earnings from PNGTS and consolidate PNGTS for all periods presented (Refer to Note 2).

Northern Border

The Partnership did not have undistributed earnings from Northern Border for the three and six months ended June 30, 2017 and 2016.

The summarized financial information for Northern Border is as follows:

(unaudited) **(millions of dollars)**	**June 30, 2017**	**December 31, 2016**
ASSETS		
Cash and cash equivalents	**16**	14
Other current assets	**34**	36
Plant, property and equipment, net	**1,077**	1,089
Other assets	**14**	14
	1,141	1,153
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	**37**	38
Deferred credits and other	**30**	28
Long-term debt, including current maturities, net	**430**	430
Partners equity		
Partners capital	**645**	659
Accumulated other comprehensive loss	**(1)**	(2)
	1,141	1,153

(unaudited) **(millions of dollars)**	**Three months ended June 30,** **2017**	**2016**	**Six months ended June 30,** **2017**	**2016**
Transmission revenues	**69**	70	**144**	144
Operating expenses	**(18)**	(18)	**(36)**	(35)
Depreciation	**(15)**	(15)	**(30)**	(29)
Financial charges and other	**(5)**	(6)	**(9)**	(11)
Net income	**31**	31	**69**	69

Great Lakes

The Partnership made an equity contribution to Great Lakes of $4 million in the first quarter of 2017. 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, 2017 and 2016.

The summarized financial information for Great Lakes is as follows:

(unaudited) **(millions of dollars)**	**June 30, 2017**	**December 31, 2016**
ASSETS		
Current assets	**61**	66
Plant, property and equipment, net	**705**	714
	766	780
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	**34**	40
Long-term debt, including current maturities, net	**269**	278
Partners equity	**463**	462
	766	780

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(unaudited) (millions of dollars)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Transmission revenues	**41**	36	**103**	97
Operating expenses	**(17)**	(15)	**(30)**	(30)
Depreciation	**(7)**	(7)	**(14)**	(14)
Financial charges and other	**(5)**	(5)	**(10)**	(11)
Net income	**12**	9	**49**	42

Iroquois

On June 1, 2017, the Partnership acquired a 49.34 percent interest in Iroquois (Refer to Note 6). The Partnership recorded no undistributed earnings from Iroquois in June 2017.

The summarized financial information for Iroquois is as follows:

(unaudited) (millions of dollars)	June 30, 2017	December 31, 2016
ASSETS		
Cash and cash equivalents	**100**	88
Other current assets	**26**	27
Plant, property and equipment, net	**595**	611
Other assets	**8**	7
	729	733
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	**15**	16
Long-term debt, including current maturities, net	**332**	338
Other non-current liabilities	**9**	5
Partners equity	**373**	374
	729	733

(unaudited) (millions of dollars)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Transmission revenues	**45**	47	**98**	100
Operating expenses	**(13)**	(15)	**(29)**	(30)
Depreciation	**(7)**	(10)	**(14)**	(19)
Financial charges and other	**(5)**	(4)	**(9)**	(8)
Net income	**20**	18	**46**	43

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NOTE 5 DEBT AND CREDIT FACILITIES

(unaudited) (millions of dollars)	June 30, 2017	Weighted Average Interest Rate for the Six Months Ended June 30, 2017	December 31, 2016 (a)	Weighted Average Interest Rate for the Year Ended December 31, 2016 (b)
TC PipeLines, LP				
Senior Credit Facility due 2021	**170**	2.22%	160	1.72%
2013 Term Loan Facility due July 2018	**500**	2.15%	500	1.73%
2015 Term Loan Facility due September 2018	**170**	2.04%	170	1.63%
4.65% Unsecured Senior Notes due 2021	**350**	4.65%(b)	350	4.65%(b)
4.375% Unsecured Senior Notes due 2025	**350**	4.375%(b)	350	4.375%(b)
3.90 % Unsecured Senior Notes due 2027	**500**	3.90%(b)		
GTN				
5.29% Unsecured Senior Notes due 2020	**100**	5.29%(b)	100	5.29%(b)
5.69% Unsecured Senior Notes due 2035	**150**	5.69%(b)	150	5.69%(b)
Unsecured Term Loan Facility due 2019	**55**	1.84%	65	1.43%
PNGTS				
5.90% Senior Secured Notes due December 2018	**36**	5.90%(b)	53	5.90%(b)
Tuscarora				
Unsecured Term Loan due 2019	**9**	2.03%	10	1.64%
3.82% Series D Senior Notes due 2017	**12**	3.82%(b)	12	3.82%(b)
	2,402		1,920	
Less: unamortized debt issuance costs and debt discount	**12**		9	
Less: current portion	**57**		52	
	2,333		1,859	

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

(b) Fixed interest rate

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 $170 million was outstanding at June 30, 2017 (December 31, 2016 - $160 million), leaving $330 million available for future borrowing. The LIBOR-based interest rate on the Senior Credit Facility was 2.34 percent at June 30, 2017 (December 31, 2016 1.92 percent).

As of June 30, 2017, 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, 2016 2.31 percent). Prior to hedging activities, the LIBOR-based interest rate on the 2013 Term Loan Facility was 2.31 percent at June 30, 2017 (December 31, 2016 1.87 percent).

The LIBOR-based interest rate on the 2015 Term Loan Facility was 2.20 percent at June 30, 2017 (December 31, 2016 1.77 percent).

The 2013 Term Loan Facility and the 2015 Term Loan Facility (Term Loan Facilities) and the Senior Credit Facility require the Partnership to maintain a certain leverage ratio (debt to adjusted cash flow [net income plus cash distributions received, extraordinary losses, interest expense, expense for taxes paid or accrued, and depreciation and amortization expense less equity earnings and extraordinary gains]) no greater than 5.00 to 1.00 for each fiscal quarter, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the leverage ratio is to be no greater than 5.50 to 1.00. The leverage ratio was 4.60 to 1.00 as of June 30, 2017.

On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 Acquisition (Refer to Note 6).The indenture for the notes contains customary investment grade covenants.

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PNGTS

PNGTS Senior Secured Notes are secured by the PNGTS long-term firm shipper contracts and its partners pledge of their equity and a guarantee of debt service for six months. PNGTS is restricted under the terms of its note purchase agreement from making cash distributions unless certain conditions are met. Before a distribution can be made, the debt service reserve account must be fully funded and PNGTS debt service coverage ratio for the preceding and succeeding twelve months must be 1.30 or greater. At June 30, 2017, the debt service coverage ratio was 1.82 for the twelve preceding months and 2.99 for the twelve succeeding months. Therefore, PNGTS was not restricted to make any cash distributions.

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, 2017 was 44.3 percent. The LIBOR-based interest rate on the GTN s Unsecured Term Loan Facility was 2.00 percent at June 30, 2017 (December 31, 2016 1.57 percent).

Tuscarora

Tuscarora s Series D Senior Notes, which require yearly principal payments until maturity, are secured by Tuscarora s transportation contracts, supporting agreements and substantially all of Tuscarora s property. The note purchase agreements contain certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners. The Series D Senior Notes contain a covenant that limits total debt to no greater than 45 percent of Tuscarora s total capitalization. Tuscarora s total debt to total capitalization ratio at June 30, 2017 was 20.46 percent. Additionally, the Series D Senior Notes require 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 3.00 to 1.00. The ratio was 3.12 to 1.00 as of June 30, 2017.

The LIBOR-based interest rate on the Tuscarora s Unsecured Term Loan Facility was 2.36 percent at June 30, 2017 (December 31, 2016 1.90 percent).

At June 30, 2017, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Third Amended and Restated Agreement of Limited Partnership (Partnership Agreement), incurring additional debt and distributions to unitholders.

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

(unaudited)
(millions of dollars)

2017	24
2018	715
2019	43
2020	100
2021	520
Thereafter	1,000
	2,402

NOTE 6 ACQUISITION

2017 Acquisition

On June 1, 2017, the Partnership acquired from subsidiaries of TransCanada a 49.34 percent interest in Iroquois Gas Transmission System, L.P. (Iroquois), including an option to acquire a further 0.66 percent interest in Iroquois, together with an additional 11.81 percent interest in PNGTS resulting in the Partnership owning a 61.71 percent interest in PNGTS (2017 Acquisition). The total purchase price of the 2017 Acquisition was $765 million plus preliminary purchase price adjustments amounting to $9 million. The purchase price consisted of (i) $710 million for the Iroquois interest (less $164 million, which reflected our 49.34 percent share of Iroquois outstanding debt on June 1) (ii) $55 million for the additional 11.81 percent interest in PNGTS (less $5 million, which reflected our 11.81% proportionate share in PNGTS debt on June 1) and (iii) preliminary working capital adjustments on PNGTS and Iroquois amounting to $3 million and $6 million, respectively. Additionally, the Partnership paid $1,000 for the option to acquire TransCanada s remaining 0.66 percent interest in Iroquois. The Partnership funded the cash portion of the 2017 Acquisition through a combination of proceeds from the May 2017 public debt offering (refer to Note 5) and borrowing under our Senior Credit Facility.

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As at the date of the 2017 Acquisition, there was significant cash on Iroquois balance sheet. Pursuant to the Purchase and Sale Agreement associated with the acquisition of the Iroquois interest, as amended, the Partnership agreed to pay $28 million plus interest to TransCanada on August 1, 2017 for its 49.34 percent share of cash determined to be surplus to Iroquois operating needs. In addition, the Partnership expects to make a final working capital adjustment payment by the end of August. The $28 million and the related interest were included in accounts payable to affiliates at June 30, 2017.

The Iroquois partners adopted a distribution resolution to address the significant cash on Iroquois balance sheet post-closing. The Partnership expects to receive the $28 million of unrestricted cash as part of its quarterly distributions from Iroquois over 11 quarters under the terms of the resolution, beginning with the second quarter 2017 distribution on August 1, 2017.

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

Iroquois net purchase price was allocated as follows:

(millions of dollars)	
Net Purchase Price (a)	581
Less: TransCanada s carrying value of Iroquois at June 1, 2017	223
Excess purchase price (b)	358

(a) Total purchase price of $710 million plus the additional consideration on Iroquois surplus cash amounting to approximately $29 million including interest less the assumption of $164 million of proportional Iroquois debt by the Partnership.

(b) The excess purchase price of $358 million was recorded as a reduction in Partners Equity.

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

The PNGTS purchase price was recorded as follows:

(millions of dollars)	
Current assets	25

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

(a) Total purchase price of $58 million (including preliminary working capital adjustment) less the assumption of $5 million of proportional PNGTS debt by the Partnership.

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

NOTE 7 PARTNERS EQUITY

ATM equity issuance program (ATM program)

During the six months ended June 30, 2017, we issued 1,542,921 common units under our ATM program generating net proceeds of approximately $90 million, plus $2 million from 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, 2017 were approximately $1 million. The net proceeds were used for general partnership purposes.

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Class B units issued to TransCanada

The Class B Units we 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.

For the year ending December 31, 2017, the Class B units equity account will be increased by the excess of 30 percent of GTN s distributions over the annual threshold of $20 million until such amount is declared for distribution and paid in the first quarter of 2018. During the six months ended June 30, 2017, the threshold has not been exceeded.

For the year ended December 31, 2016, the Class B distribution was $22 million and was declared and paid in the first quarter of 2017.

Common unit issuance subject to rescission

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

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

No unitholder claimed or attempted to exercise any rescission rights prior to their expiry dates and the final rights related to the sales of such units expired on May 19, 2017. Therefore, all the common units subject to rescission were reclassified back to partners equity on our consolidated balance sheet at June 30, 2017.

NOTE 8 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 attributed to PNGTS former parent, amounts attributable to the General Partner and Class B units, by the weighted average number of common units outstanding.

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

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

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Net income per common unit was determined as follows:

[redacted]				
Net income attributable to controlling interests (a)	**55**	55	**132**	130
[redacted]				
Net income attributable to General and Limited Partners	**55**	54	**130**	127
[redacted]				
Net income attributable to the Class B units (d)		(1)		(1)
[redacted]				
Net income attributable to General Partner s two percent interest	**(2)**	(1)	**(3)**	(2)
[redacted]				
Weighted average common units outstanding *(millions)* basic and diluted	**68.9**	65.5(e)	**68.6**	64.9(e)
[redacted]				

(a) Recast to consolidate PNGTS for all periods presented (Refer to Notes 2 and 6).

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

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

(d) During the three and six months ended June 30, 2017, no amounts were allocated to the Class B units as the annual threshold of $20 million has not been exceeded. During the six months ended June 30, 2016, 30 percent of GTN s total distributable cash flow was $21 million. As a result of exceeding the $20 million threshold, $1 million of net income attributable to controlling interests was allocated to the Class B units during the three and six months ended June 30, 2016.

(e) Includes the common units subject to rescission. These units are treated as outstanding for financial reporting purposes. Refer to Note 7.

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

NOTE 9 CASH DISTRIBUTIONS

During the three and six months ended June 30, 2017, the Partnership distributed $0.94 and $1.88 per common unit, respectively (June 30, 2016 $0.89 and $1.78 per common unit) for a total of $68 million and $135 million, respectively (June 30, 2016 - $60 million and $119 million).

The distribution paid to our General Partner during the three months ended June 30, 2017 for its effective two percent general partner interest was $1 million along with an IDR payment of $2 million for a total distribution of $3 million (June 30, 2016 - $1 million for the effective two percent interest and a $1 million IDR payment).

The distribution paid to our General Partner during the six months ended June 30, 2017 for its effective two percent general partner interest was $2 million along with an IDR payment of $4 million for a total distribution of $6 million (June 30, 2016 - $2 million for the effective two percent interest and a $2 million IDR payment).

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NOTE 10 CHANGE IN OPERATING WORKING CAPITAL

(unaudited) (millions of dollars)	Six months ended June 30, 2017	 2016 (a)
Change in accounts receivable and other	**11**	2
Change in other current assets	**2**	2
Change in accounts payable and accrued liabilities(b)	**(5)**	1
Change in accounts payable to affiliates	**(2)**	(2)
Change in state income taxes payable		8
Change in accrued interest	**1**	1
Change in operating working capital	**7**	12

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

(b) The accrual of $10 million for the construction of GTN s Carty Lateral in December 31, 2015 was paid during the first quarter 2016. Accordingly, the payment was reported as capital expenditures in our cash flow statement during the current period.

NOTE 11 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the General Partner. The General Partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the General Partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the General Partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the General Partner in its sole discretion. For both the three and six months ended June 30, 2017 and 2016, 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 for the three and six months ended June 30, 2017 and 2016 by TransCanada s subsidiaries and amounts payable to TransCanada s subsidiaries at June 30, 2017 and December 31, 2016 are summarized in the following tables:

	Three months ended	Six months ended

(unaudited) (millions of dollars)	June 30, 2017	2016	June 30, 2017	2016
Capital and operating costs charged by TransCanada s subsidiaries to:				
Great Lakes (a)	**9**	7	**17**	14
Northern Border (a)	**10**	9	**20**	15
GTN	**9**	7	**16**	13
Bison	**1**	1	**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 (a)	**4**	3	**7**	6
Northern Border (a)	**4**	3	**7**	6
GTN	**7**	6	**14**	11
Bison	**1**	1	**2**	2
North Baja	**1**	1	**2**	2
Tuscarora	**1**	1	**2**	2
PNGTS (b)	**1**	1	**2**	2

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(unaudited) (millions of dollars)	June 30, 2017	December 31, 2016
Net amounts payable to TransCanada s subsidiaries is as follows:		
Great Lakes (a)	**4**	4
Northern Border (a)	**4**	4
GTN	**3**	3
Bison	**1**	1
North Baja		1
Tuscarora		1
PNGTS	**1**	1

(a) Represents 100 percent of the costs.

(b) Recast to consolidate PNGTS for all periods presented (Refer to Note 2).

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, 2017, Great Lakes earned 43 percent and 57 percent of transportation revenues from TransCanada and its affiliates, respectively (June 30, 2016 64 percent and 71 percent).

At June 30, 2017, $1 million was included in Great Lakes receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2016 $19 million).

Great Lakes operates under a FERC approved 2013 rate settlement that includes a revenue sharing mechanism that requires Great Lakes to share with its shippers certain percentages of any qualifying revenues earned above a certain return on equity threshold. For the year ended December 31, 2016, Great Lakes recorded an estimated 2016 revenue sharing provision of $7.2 million. For the three and six months ended June 30, 2017, Great Lakes recorded an estimated 2017 revenue sharing provision of $7 million and $10 million, respectively. Great Lakes expects that a significant percentage of this refund will be paid to its affiliates.

PNGTS earns transportation revenues from TransCanada and its affiliates. For the three and six months ended June 30, 2017, PNGTS earned 2 percent and 1 percent of transportation revenues from TransCanada and its affiliates, respectively (June 30, 2016 5 percent and 3 percent).

At June 30, 2017, nil was included in PNGTS receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2016 nil).

NOTE 12 FAIR VALUE MEASUREMENTS

(a) Fair Value Hierarchy

Under ASC 820, *Fair Value Measurements and Disclosures*, fair value measurements are characterized in one of three levels based upon the 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 in Level 2 of the fair value hierarchy for fair value disclosure purposes. Interest rate derivative assets and liabilities are classified in Level 2 for all periods presented where the fair value is determined by using valuation techniques that refer to observable market data or estimated market

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prices. The estimated fair value of the Partnership s debt as at June 30, 2017 and December 31, 2016 was $2,465 million and $1,908 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 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, 2017, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $2 million (both on a gross and net basis). At December 31, 2016, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $1 million and a liability of $1 million (on a gross basis) and an asset of nil million (on a net basis). The Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges for the three and six months ended June 30, 2017 and 2016. The change in fair value of interest rate derivative instruments recognized in other comprehensive income was nil and a gain of $1 million for the three and six months ended June 30, 2017, respectively (June 30, 2016 loss of $1 million and a loss of $3 million). For the three and six months ended June 30, 2017, the net realized loss related to the interest rate swaps was nil, and was included in financial charges and other (June 30, 2016 $1 million for both periods). Refer to Note 14 Financial Charges and Other.

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 is currently being amortized against earnings over the life of the PNGTS Senior Secured Notes. At June 30, 2017, our 61.71 percent proportionate share of net unamortized loss on PNGTS included in other comprehensive income was $1 million (December 31, 2016 - $2 million). For the three and six months ended June 30, 2017, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $1 million (June 30, 2016 $1 million).

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, 2017 (net asset of nil million as of December 31, 2016).

NOTE 13 ACCOUNTS RECEIVABLE AND OTHER

(unaudited) **(millions of dollars)**	**June 30, 2017**	**December 31, 2016 (a)**

Trade accounts receivable, net of allowance of nil	**35**	44
Imbalance receivable from affiliates	**1**	2
Other	**1**	1
	37	47

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

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NOTE 14 FINANCIAL CHARGES AND OTHER

(unaudited) (millions of dollars)	Three months ended June 30, 2017	2016(b)	Six months ended June 30, 2017	2016(b)
Interest Expense (a)	**19**	16	**36**	35
PNGTS amortization of derivative loss on derivative instruments *(Note 12)* (b)	**1**	1	**1**	1
Net realized loss related to the interest rate swaps		1		1
Other Income	**(1)**	(1)	**(1)**	(2)
	19	17	**36**	35

(a) Includes amortization of debt issuance costs and discount costs.

(b) Recast to consolidate PNGTS for all periods presented (Refer to Note 2).

NOTE 15 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. On September 16, 2015, following a jury trial, the federal district court judge entered a judgment in the amount of $32.9 million in favor of Great Lakes. On September 20, 2015, Essar appealed the decision to the United States Court of Appeals for the Eighth Circuit (Eighth Circuit) based on an allegation of improper jurisdiction and a number of other rulings by the federal district judge. Essar was required to post a performance bond for the full value of the judgment pending appeal. In July 2016, Essar Minnesota filed for Bankruptcy. The performance bond was released into the bankruptcy court proceedings. The Foreign Essar Affiliates have not filed for bankruptcy. The Eighth Circuit heard the appeal on October 20, 2016. A decision on the appeal was received in December 2016 and the Eighth Circuit vacated Great Lakes judgment against Essar finding that there was no federal jurisdiction. Great Lakes filed a Request for Rehearing with the Eighth Circuit and it was denied in January 2017. Great Lakes currently is proceeding against Essar Minnesota in the bankruptcy court and its case against the Foreign Essar Affiliates in Minnesota state court remains pending. In April, after reaching agreement with creditors on an allowed claim, the Bankruptcy court approved Great Lakes claim in the amount of $31.5 million.

NOTE 16 REGULATORY

North Baja On January 6, 2017, North Baja notified FERC that current market conditions do not support the replacement of the compression that was temporarily abandoned in 2013 and requested authorization to permanently abandon two compressor units and a nominal volume of unsubscribed firm capacity. FERC approved the permanent abandonment request on February 16, 2017. The abandonments will not have any impact on existing firm transportation service.

Great Lakes- Great Lakes is required to file a new section 4 rate case with rates effective no later than January 1, 2018 as part of the settlement agreement with customers approved in November 2013. On March 31, 2017, Great Lakes filed its rate case pursuant to Section 4 of the Natural Gas Act (2017 Rate Case). The rates proposed in the filing will become effective on October 1, 2017, subject to refund, if alternate resolution to the proceeding is not reached prior to that date. Great Lakes has initiated customer discussions regarding the details of the filing and is currently seeking to achieve a mutually beneficial resolution through settlement with its customers.

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

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direct the activities of the VIE that most significantly impact the VIEs economic performance and (2) the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

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

Consolidated VIEs

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

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

(unaudited) **(millions of dollars)**	**June 30, 2017**	**December 31, 2016(a)**
ASSETS (LIABILITIES) *		
Cash and cash equivalents	**13**	14
Accounts receivable and other	**26**	33
Inventories	**6**	6
Other current assets	**3**	6
Equity investments	**1,138**	918
Plant, property and equipment	**1,137**	1,146
Other assets	**1**	2
Accounts payable and accrued liabilities	**(20)**	(21)
Accounts payable to affiliates, net	**(39)**	(32)
Distributions payable		(3)
Accrued interest	**(1)**	(2)
Current portion of long-term debt	**(57)**	(52)
Long-term debt	**(304)**	(337)
Other liabilities	**(26)**	(25)
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.

(a) Recast to consolidate PNGTS for all periods presented (Refer to Note 2).

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, 2017 and December 31, 2016 relate primarily to utility plant. At June 30, 2017 and December 31, 2016 the New Hampshire BPT effective tax rate was 3.8 percent for both periods and was applied to PNGTS taxable income.

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(unaudited) (millions of dollars)	Three months ended June 30, 2017	2016(a)	Six months ended June 30, 2017	2016(a)
State income taxes				
Current			**1**	8
Deferred				(7)
			1	1

(a) Recast to consolidate PNGTS for all periods presented (Refer to Note 2).

NOTE 19 SUBSEQUENT EVENTS

Management of the Partnership has reviewed subsequent events through August 3, 2017, 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 20, 2017, the board of directors of the General Partner declared the Partnership s second quarter 2017 cash distribution in the amount of $1.00 per common unit payable on August 11, 2017 to unitholders of record as of August 1, 2017. The declared distribution reflects a $0.06 per common unit increase to the Partnership s first quarter 2017 quarterly distribution. The declared distribution totaled $74 million and is payable in the following manner: $69 million to common unitholders (including $6 million to the General Partner as a holder of 5,797,106 common units and $11 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $5 million to the General Partner, which included $2 million for its effective two percent general partner interest and $3 million in respect of its IDRs.

Northern Border declared its June 2017 distribution of $14 million on July 7, 2017, of which the Partnership will receive its 50 percent share or $7 million on July 31, 2017.

Great Lakes declared its second quarter 2017 distribution of 15 million on July 18, 2017, of which the Partnership will receive its 46.45 percent share or $7 million on August 1, 2017.

Iroquois declared its second quarter 2017 distribution of $28 million on July 27, 2017, of which the Partnership received its 49.34 percent share or $14 million on August 1, 2017.

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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, 2016, in which certain parts of the report were amended through the Partnership s filing of Current Report on Form 8-K dated August 3, 2017 to give retrospective adjustments to include the results of operations and financial position of PNGTS for all periods presented (Refer to Note 2 in Item 1. Financial Statements of this Quarterly Report on Form 10-Q).

RECENT BUSINESS DEVELOPMENTS

Cash Distributions

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

On July 20, 2017, the board of directors of our General Partner declared the Partnership s second quarter 2017 cash distribution in the amount of $1.00 per common unit, payable on August 11, 2017 to unitholders of record as of August 1, 2017. The declared distribution totaled $74 million and is payable in the following manner: $69 million to common unitholders (including $6 million to the General Partner as a holder of 5,797,106 common units and $11 million to another subsidiary of TransCanada as holder of 11,287,725 common units) and $5 million to our General Partner, which included $2 million for its effective two percent general partner interest and $3 million in respect of its IDRs. The declared distribution reflects a 6 percent per common unit increase to the first quarter 2017 quarterly distribution.

Great Lakes **-** Great Lakes is required to file a new Section 4 rate case with rates effective no later than January 1, 2018 as part of the settlement agreement with customers approved in November 2013. On March 31, 2017, Great Lakes filed its rate case pursuant to Section 4 of the Natural Gas Act (2017 Rate Case). The rates proposed in the filing will become effective on October 1, 2017, subject to refund, if alternate resolution to the proceeding is not reached prior to that date. Great Lakes is currently seeking to achieve a mutually beneficial resolution through settlement with its customers.

On April 24, 2017, Great Lakes reached an agreement on the terms of a potential new long-term transportation capacity contract with its affiliate, TransCanada. The contract is for a term of 10 years with a total contract value of up to $758 million. The contract may commence as soon as November 1, 2017 and contains termination options beginning in year three. The contract is subject to the satisfaction of certain conditions, including but not limited to approval by the Canadian National Energy Board of an associated contract between TransCanada and third party customers. Great Lakes current rate structure includes a revenue sharing mechanism that requires Great Lakes to share with its customers certain percentages of any qualifying revenues earned above a calculated return on equity threshold. Additionally, Great Lakes is currently pursuing resolution of its 2017 Rate Case. We cannot predict the cumulative impact of these circumstances on the Partnership s earnings and cash flows at this time.

Debt Offering On May 25, 2017, the Partnership closed a $500 million public offering of senior unsecured notes bearing an interest rate of 3.90 percent maturing May 25, 2027. The net proceeds of $497 million were used to fund a portion of the 2017 Acquisition (Refer to Note 6 within Item 1. Financial Statements of this Quarterly Report on Form 10Q).

2017 Acquisition On June 1, 2017, the Partnership completed the acquisitions of a 49.34 percent interest in Iroquois from subsidiaries of TransCanada including an option to acquire a further 0.66 percent interest in Iroquois, together with an additional 11.81 percent interest in PNGTS that resulted in the Partnership owning a 61.71 percent interest in PNGTS. The total purchase price of the 2017 Acquisition was $765 million plus preliminary purchase price adjustments amounting to approximately $9 million. The purchase price consisted of (i) $710 million for the Iroquois interest (less $164 million, which reflected the Partnership s 49.34 percent share of Iroquois outstanding debt at the time of the 2017 Acquisition (ii) $55 million for the additional 11.81 percent in PNGTS (less $5 million, which reflected our 11.81 percent share in PNGTS outstanding debt at the time of the 2017 Acquisition) and (iii) preliminary working capital adjustments on PNGTS and Iroquois amounting to $3 million and $6 million, respectively. The Partnership funded the cash portion of the 2017 Acquisition through a combination of proceeds from the May 25, 2017 public debt offering and borrowing under its Senior Credit Facility.

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As at the date of the 2017 Acquisition, there was significant cash on Iroquois balance sheet. Pursuant to the Purchase and Sale Agreement associated with the acquisition of the Iroquois interest, as amended, the Partnership agreed to pay $28 million plus interest to TransCanada on August 1, 2017 for its 49.34 percent share of cash determined to be surplus to Iroquois operating needs. In addition, the Partnership expects to make a final working capital adjustment payment by the end of August. The $28 million and the related interest were included in accounts payable to affiliates at June 30, 2017.

The Iroquois partners adopted a distribution resolution to address the significant cash on Iroquois balance sheet post-closing. The Partnership expects to receive the $28 million of unrestricted cash as part of its quarterly distributions from Iroquois over 11 quarters under the terms of the resolution, beginning with the second quarter 2017 distribution on August 1, 2017.

The Iroquois pipeline transports natural gas under long-term contracts and extends from the TransCanada Mainline system at the U.S. border near Waddington, New York to markets in the U.S. northeast, including New York City, Long Island and Connecticut. Iroquois provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, directly or indirectly, through interconnecting pipelines and exchanges throughout the northeastern U.S. Both the Iroquois and PNGTS pipelines are critical natural gas infrastructure systems in the Northeast U.S. market and the addition of Iroquois to the Partnership s asset portfolio will further diversify our cash flow.

Northern Border Northern Border revenues are now substantially supported by firm transportation contracts through March 2020. The continued successful renewals of these contracts provide a strong indication of Northern Border s attractiveness to its customers.

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 equity interests in Northern Border, Great Lakes, and effective June 1, 2017, Iroquois and full ownerships of GTN, Bison, North Baja and Tuscarora and beginning also on June 1, 2017, 61.71 percent ownership in PNGTS 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, 2017	2016(a)	$ Change*	% Change*	Six months ended June 30, 2017	2016(a)	$ Change*	% Change*
Transmission revenues	**101**	101			213	212	1	**
Equity earnings	**24**	20	4	20	60	53	7	13
Operating, maintenance and administrative	**(26)**	(23)	(3)	(13)	(49)	(43)	(6)	(14)
Depreciation	**(25)**	(24)	(1)	(4)	(49)	(48)	(1)	(2)
Financial charges and other	**(19)**	(17)	(2)	(12)	(36)	(35)	(1)	(3)
Net income before taxes	**55**	57	(2)	(4)	139	139		
State income taxes					(1)	(1)		
Net income	**55**	57	(2)	(4)	138	138		
Net income attributable to non-controlling interests		2	2	100	6	8	2	25
Net income attributable to controlling interests	**55**	55			132	130	2	2

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

** less than 1 percent

(a) Financial information was recast to consolidate PNGTS for all periods presented (Refer to Note 2).

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Three Months Ended June 30, 2017 compared to Same Period in 2016

Net income attributable to controlling interests - The Partnership s net income attributable to controlling interests was comparable to prior period due to the net effect of higher equity earnings partially offset by higher costs.

Transmission revenues Comparable to prior year primarily due to higher discretionary revenues on short-term services sold by GTN offset by lower discretionary revenues on short-term services sold by PNGTS.

Equity Earnings - The $4 million increase was primarily due to the addition of equity earnings on Iroquois, a reflection of the addition of Iroquois to our portfolio of assets effective June 1, 2017.

Operating, maintenance and administrative costs - The $3 million increase was mainly attributable to higher pipeline integrity and other operational costs on GTN related to higher gas flows on the pipeline.

Financial charges and other - The $2 million increase was mainly 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 lower due to lower earnings from PNGTS during the period.

Six Months Ended June 30, 2017 compared to Same Period in 2016

Net income attributable to controlling interests - The Partnership s net income attributable to controlling interests increased by $2 million or 2 percent due higher equity earnings partially offset by higher costs.

Transmission revenues Comparable to prior year primarily due to higher discretionary revenues on short-term services sold by GTN offset by lower discretionary revenues on short-term services sold by PNGTS.

Equity Earnings - The $7 million increase was primarily due the addition of equity earnings on Iroquois, a reflection of the addition of Iroquois to our portfolio of assets effective June 1, 2017 and higher equity earnings on Great Lakes due to its higher transportation revenues.

Operating, maintenance and administrative costs - The $6 million increase was mainly attributable to higher pipeline integrity and other operational costs on GTN related to higher gas flows on the pipeline.

Financial charges and other - The $1 million increase was mainly 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 lower due to lower earnings from PNGTS during the period.

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

As discussed in Note 7 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 beginning in the third quarter of 2017.

During the six months ended June 30, 2016, 30 percent of GTN s total distributable cash flow was $21 million. As a result of exceeding the $20 million threshold, $1 million of net income attributable to controlling interests was allocated to the Class B units during the three and six months ended June 30, 2016.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our principal sources of liquidity and cash flows include distributions received from our equity investments, operating cash flows from our subsidiaries, public offerings of debt and equity, term loans and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions (including those distributions made to TransCanada through our General Partner and as holder of all our Class B units) primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity. Overall, we believe that our pipeline systems ability to obtain financing at reasonable rates, together with a history of consistent cash flow from

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operating activities, provide a solid foundation to meet future liquidity and capital requirements. We expect to be able to fund our liquidity requirements, including our distributions and required debt repayments, at the Partnership level over the next 12 months utilizing our cash flow and, if required, our existing Senior Credit Facility.

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

(unaudited) **(millions of dollars)**	**June 30, 2017**	**December 31, 2016**
Total capacity under the Senior Credit Facility	500	500
Less: Outstanding borrowings under the Senior Credit Facility	170	160
Available capacity under the Senior Credit Facility	330	340

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

Capital expenditures are funded by a variety of sources, including cash generated from operating activities, borrowings under bank credit facilities, issuance of senior unsecured notes or equity contributions from our pipeline systems owners. The ability of our pipeline systems to access the debt capital markets under reasonable terms depends on their financial position and general market conditions.

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

Cash Flow Analysis for the Six Months Ended June 30, 2017 compared to Same Period in 2016

(unaudited) **(millions of dollars)**	**Six months ended June 30,** **2017**	**2016 (a)**
Net cash provided by (used in):		
Operating activities	**205**	235
Investing activities	**(625)**	(213)
Financing activities	**407**	(25)
Net decrease in cash and cash equivalents	**(13)**	(3)
Cash and cash equivalents at beginning of the period	**64**	55
Cash and cash equivalents at end of the period	**51**	52

(a) Financial information was recast to consolidate PNGTS for all periods presented (Refer to Note 2).

Operating Cash Flows

Net cash provided by operating activities decreased by $30 million in the six months ended June 30, 2017 compared to the same period in 2016 primarily due to lower distributions from Great Lakes and Northern Border in 2017. Distributions received in the first quarter of 2016 from Great Lakes were higher than on a run-rate basis due to the resolution of certain regulatory proceedings in the fourth quarter of 2015 which inflated its results during that period and resulted in higher cash flow which was paid to the Partnership in the first quarter of 2016 and not applicable in the first quarter of 2017. Additionally, the Partnership received lower distributions from Northern Border in the current period compared to the same period in 2016 primarily due to the change in Northern Border s distribution policy during the second quarter of 2016 from a lagged quarterly distribution to a more timely monthly distribution that resulted in a larger distribution in the second quarter of 2016.

Investing Cash Flows

Net cash used in investing activities increased by $412 million in the six months ended June 30, 2017 compared to the same period in 2016. On January 1, 2016, we invested $193 million to acquire a 49.9 percent interest in PNGTS and on

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June 1, 2017, we invested $552 million to acquire a 49.34 percent interest in Iroquois and $53 million to acquire an additional 11.81 percent of PNGTS.

Financing Cash Flows

The net change in cash from our financing activities was approximately $432 million in the six months ended June 30, 2017 compared to the same period in 2016 primarily due to the net effect of:

- $439 million increase in net issuances of debt in 2017 primarily to finance the 2017 Acquisition;
- $9 million increase in our ATM equity issuances in 2017 as compared to 2016;
- $16 million increase in distributions paid to our common units and to our General Partner in respect of its two percent general partner interest and IDRs;
- $10 million increase in distributions paid to Class B units in 2017 as compared to 2016; and
- $4 million decrease in distributions paid to non-controlling interest due lower revenues on PNGTS compared to the previous periods
- $7 million decrease in distributions paid to TransCanada as the former parent of PNGTS primarily due to the Partnership s acquisition of a 49.9 percent interest in PNGTS effective January 1, 2016 and additional 11.81 percent effective June 1, 2017.

Cash Flow Outlook

Operating Cash Flow Outlook

Northern Border declared its June 2017 distribution of $14 million on July 7, 2017, of which the Partnership received its 50 percent share or $7 million. The distribution was paid on July 31, 2017.

Great Lakes declared its second quarter 2017 distribution of $15 million on July 18, 2017, of which the Partnership received its 46.45 percent share or $7 million. The distribution was paid on August 1, 2017.

Iroquois declared its second quarter 2017 distribution of $28 million on July 27, 2017, of which the Partnership received its 49.34 percent share or $14 million on August 1, 2017.

Our equity investee Iroquois has $2.8 million of scheduled debt repayments for the remainder of 2017 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 2017. 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 2017 to further fund debt repayments. This is consistent with prior years.

Our consolidated entities have commitments of $10 million as of June 30, 2017 in connection with various maintenance and general plant projects.

Our expected total growth and maintenance capital expenditures on our pipeline systems as outlined in the Management Discussion and Analysis of Financial Condition and Results of Operations for the year ended December 31, 2016 Consolidated Financial Statements and Notes thereto included as Exhibit 99.3 of the Current Report on Form 8-K filed with the SEC on August 3, 2017 remain unchanged.

Financing Cash Flow Outlook

On July 20, 2017, the board of directors of our General Partner declared the Partnership s second quarter 2017 cash distribution in the amount of $1.00 per common unit payable on August 11, 2017 to unitholders of record as of August 1, 2017. Please see Recent Business Developments.

Tuscarora s $12 million Series D Senior Notes are due on August 20, 2017. The Partnership expects to refinance the entire principal amount upon maturity.

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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, 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),
- Interest expense,
- 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 2017 equal 30 percent of GTN s distributable cash flow less $20 million.

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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 Non-GAAP Financial Measures

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:

(unaudited) (millions of dollars)	Three months ended June 30, 2017	 2016 (a)	Six months ended June 30, 2017	 2016(a)
Net income	**55**	57	**138**	138
Add:				
Interest expense(b)	**20**	18	**37**	37
Depreciation and amortization	**25**	24	**49**	48
Income taxes			**1**	1
EBITDA	**100**	99	**225**	224
Add:				
Distributions from equity investments(c)				
Northern Border	**20**	21	**40**	44
Great Lakes	**7**	6	**27**	23
Iroquois (d)	**14**		**14**	
	41	27	**81**	67
Less:				
Equity earnings:				
Northern Border	**(15)**	(16)	**(34)**	(34)
Great Lakes	**(6)**	(4)	**(23)**	(19)
Iroquois	**(3)**		**(3)**	
	(24)	(20)	**(60)**	(53)
Less:				
Equity AFUDC				
Interest expense	**(20)**	(18)	**(37)**	(37)
Income taxes			**(1)**	(1)
Distributions to non-controlling interests(e)	**(3)**		**(8)**	(9)
Distributions to TransCanada as PNGTS former parent(f)		(1)	**(1)**	(3)
Maintenance capital expenditures (g)	**(7)**	(5)	**(17)**	(6)
	(30)	(24)	**(64)**	(56)

Total Distributable Cash Flow	**87**	82	**182**	182
General Partner distributions declared (h)	**(5)**	(3)	**(8)**	(5)
Distributions allocable to Class B units (i)		(1)		(1)
Distributable Cash Flow	**82**	78	**174**	176

(a) Financial information was recast to consolidate PNGTS for all periods presented. Please see Basis of Presentation section within Item 2, Management Discussion and Analysis of Financial Condition and Results of Operations for more information.

(b) Interest expense as presented includes net realized loss related to the interest rate swaps and amortization of realized loss on PNGTS derivative instruments. Refer to Note 14 within Item 1. Financial Statements.

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(c) 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.

(d) Our equity investee Iroquois declared its second quarter 2017 distribution of $28 million on July 27, 2017, of which the Partnership received its 49.34 percent share or $14 million on August 1, 2017. The amount that was received by the Partnership includes its share of the Iroquois unrestricted cash distribution amounting to approximately $2.6 million. Refer to Note 6 within Item 1. Financial Statements.

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

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

(g) The Partnership s maintenance capital expenditures include cash 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.

(h) Distributions declared to the General Partner for the three and six months ended June 30, 2017 included an incentive distribution of approximately $3 million and $5 million, respectively (June 30, 2016 $2 million and $3 million).

(i) During the six months ended June 30, 2017, 30 percent of GTN s total distributions amounted to $19 million. Therefore, no distribution was allocated to the Class B units as the threshold level for 2017 of $ 20 million has not been exceeded. We expect to exceed the threshold in third quarter of 2017 and will accordingly allocate almost all of the 30 percent of distributable cash flow of GTN for the third quarter to the Class B units and the full 30 percent to the Class B units in the fourth quarter.. During the six months ended June 30, 2016, $1 million was allocated to the Class B units representing the amount that exceeded the threshold level of $20 million.

Please read Notes 7 and 8 within Item 1. Financial Statements for additional disclosures on the Class B units.

Three months ended June 30, 2017 Compared with Same Period in 2016

Our EBITDA was comparable to the same period in prior year primarily due to the addition of equity earnings on Iroquois beginning June 1, 2017 offset by an increase in operational costs as discussed in more detail under the Results of Operations section.

Our distributable cash flow increased by $4 million in the second quarter of 2017 compared to the same period in 2016 due to the net effect of:

- addition of 49.34 percent share of Iroquois second quarter 2017 distribution;
- higher maintenance capital expenditures related to major compression equipment overhauls on GTN s pipeline system ;
- increased interest expense due to additional borrowings to finance the 2017 Acquisition; and
- higher distributions to our General Partner in respect of its two percent general partner interest and IDRs.

Six Months Ended June 30, 2017 Compared With Same Period in 2016

Our EBITDA was comparable to the same period in prior year primarily due to the addition of equity earnings on Iroquois beginning June 1, 2017 offset by an increase in operational costs as discussed in more detail under the Results of Operations section.

Our distributable cash flow decreased by $2 million in the six months ended June 30, 2017 compared to the same period in 2016 due to the net effect of:

- addition of 49.34 percent share of Iroquois second quarter 2017 distribution;
- higher maintenance capital expenditures related to major compression equipment overhauls on GTN s pipeline system ; and
- higher distributions to our General Partner in respect of its two percent general partner interest and IDRs.

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Contractual Obligations

The Partnership s Contractual Obligations

The Partnership s contractual obligations related to debt as of June 30, 2017 included the following:

(unaudited) (millions of dollars)	Payments Due by Period Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Six Months Ended June 30, 2017
TC PipeLines, LP						
Senior Credit Facility due 2027	170			170		2.22%
2013 Term Loan Facility due July 2018	500		500			2.15%
2015 Term Loan Facility due September 2018	170		170			2.04%
4.65% Senior Notes due 2021	350			350		4.65%(a)
4.375% Senior Notes due 2025	350				350	4.375%(a)
3.9% Senior Notes due 2027	500				500	3.90%(a)
GTN						
5.29% Unsecured Senior Notes due 2020	100		100			5.29%(a)
5.69% Unsecured Senior Notes due 2035	150				150	5.69%(a)
Unsecured Term Loan Facility due 2019	55	20	35			1.84%
PNGTS						
5.90% Senior Secured Notes due December 2018	36	24	12			5.90%(a)
Tuscarora						
Unsecured Term Loan due 2019	9	1	8			2.03%
3.82% Series D Senior Notes due 2017	12	12				3.82%(a)
	2,402	57	825	520	1,000	

(a) 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, 2017 was $2,465 million.

Please read Note 5 within Item 1. Financial Information for additional information regarding the Partnership s debt.

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Summary of Northern Border s Contractual Obligations

Northern Border s contractual obligations related to debt as of June 30, 2017 included the following:

(unaudited) (millions of dollars)	Total	Payments Due by Period (a) Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate for the Six Months Ended June 30, 2017
$200 million Credit Agreement due 2020	181			181		2.04%
7.50% Senior Notes due 2021	250			250		7.50%(b)
	431			431		

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

(b) Fixed interest rate

As of June 30, 2017, $181 million was outstanding under Northern Border s $200 million revolving credit agreement, leaving $19 million available for future borrowings. At June 30, 2017, Northern Border was in compliance with all of its financial covenants.

As of June 30, 2017, Northern Border had not utilized the $100 million 364-day revolving credit facility.

Northern Border has commitments of $12 million as of June 30, 2017 in connection with 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, 2017 included the following:

(unaudited) (millions of dollars)	Total	Payments Due by Period (a) Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years	Weighted Average Interest Rate

						for the Six Months Ended June 30, 2017
6.73% series Senior Notes due 2017 to 2018	9	9				6.73%(b)
9.09% series Senior Notes due 2017 and 2021	50	10	20	20		9.09%(b)
6.95% series Senior Notes due 2019 and 2028	110		22	22	66	6.95%(b)
8.08% series Senior Notes due 2021 and 2030	100			20	80	8.08%(b)
	269	19	42	62	146	

(a) Represents 100 percent of Great Lakes debt obligations.

(b) 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 $145 million of Great Lakes partners capital was restricted as to distributions as of June 30, 2017 (December 31, 2016 $150 million). Great Lakes was in compliance with all of its financial covenants at June 30, 2017.

Great Lakes has commitments of $3 million as of June 30, 2017 in connection with pipeline integrity, major overhaul projects, and right of way renewals.

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Summary of Iroquois Contractual Obligations

Iroquois contractual obligations related to debt as of June 30, 2017 included the following:

		Payments Due by Period (a)				
(unaudited) (millions of dollars)	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**	**Weighted Average Interest Rate for the Six Months Ended June 30, 2017**
6.63% series Senior Notes due 2019	140		140			6.63%(b)
4.84% series Senior Notes due 2020	150		150			4.84%(b)
6.10% series Senior Notes due 2027	42	5	10	7	20	6.10%(b)
	332	5	300	7	20	

(a) Represents 100 percent of Iroquois debt obligations.

(b) Fixed interest rate

Iroquois has $2 million of material commitments as of June 30, 2017.

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%, the debt service coverage ratio must be at least 1.25 times for the four preceding quarters. At June 30, 2017, the debt/capitalization ratio was 47% and the debt service coverage ratio was 6.17 times, therefore, Iroquois was not restricted from making any cash distributions.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions, which cannot be known with certainty, that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ. There were no significant changes to the Partnership s critical accounting estimates during the three and six months ended June 30, 2017. Information about our critical accounting estimates is included in our Annual Report on Form 10-K for the year ended December 31, 2016.

Our significant accounting policies have remained unchanged since December 31, 2016 except as described in Note 3 within Item 1. Financial Statements, of this quarterly report on Form 10-Q. A summary of our significant accounting policies can be found in our audited financial statements and notes thereto for the year ended December 31, 2016 included as exhibit 99.2 in our Current Report on Form 8-K dated August 3, 2017. (Refer also to Note 2 in Item 1. Financial Statements of this Quarterly Report on Form 10-Q).

RELATED PARTY TRANSACTIONS

Please read Note 6 and 11 within Item 1. Financial Statements for information regarding related party transactions.

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, 2017, the Partnership s interest rate exposure resulted from our floating rate Senior Credit Facility, 2015 Term Loan Facility, GTN s Unsecured Term Loan Facility and Tuscarora s Unsecured Term Loan Facility, under which $404 million, or 17 percent, of our outstanding debt was subject to variability in LIBOR interest rates. As of December 31, 2016, the Partnership s interest rate exposure resulted from our floating rate Senior Credit Facility, 2015 Term Loan Facility, GTN s Unsecured Term Loan Facility and Tuscarora s Unsecured Term Loan Facility, under which $405 million or 21 percent of our outstanding debt was subject to variability in LIBOR interest rates.

As of June 30, 2017, the variable interest rate exposure related to 2013 Term Loan Facility was hedged by fixed interest rate swap arrangements and our effective interest rate was 2.31 percent. If interest rates hypothetically increased (decreased) by one percent, 100 basis points, compared with rates in effect at June 30, 2017, our annual interest expense would increase (decrease) and net income would decrease (increase) by approximately $4 million.

As of June 30, 2017 and December 31, 2016, $181 million, or 42 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, 2017, Northern Border s annual interest expense would increase (decrease) and its net income would decrease (increase) by approximately $2 million.

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

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

- Swaps contractual agreements between two parties to exchange streams of payments over time according to specified terms.

- Options contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period.

The 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, 2017, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $2 million (both on a gross and net basis). At December 31, 2016, the fair value of the interest rate swaps accounted for as cash flow hedges was an asset of $1 million and a liability of $1 million (on a gross basis) and an asset of nil million (on a net basis). The Partnership did not record any amounts in net income related to ineffectiveness for interest rate hedges for the three and six months ended June 30, 2017 and 2016. The change in fair value of interest rate derivative instruments recognized in other comprehensive income was nil and a gain of $1 million for the three and six months ended June 30, 2017, respectively (June 30, 2016 loss of $1 million and a loss of $3 million). For the three and six months ended June 30, 2017, the net realized loss related to the interest rate swaps was nil, and was included in financial charges and other (June 30, 2016 $1 million for both periods). Refer to Note 14 within Item 1. Financial Statements.

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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 is currently being amortized against earnings over the life of the PNGTS Senior Secured Notes. At June 30, 2017, our 61.71 percent proportionate share of net unamortized loss on PNGTS included in other comprehensive income was $1 million (December 31, 2016 - $2 million). For the three and six months ended June 30, 2017, our 61.71 percent proportionate share of the amortization of realized loss on derivative instruments was $1 million (June 30, 2016 $1 million).

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, 2017 (net asset of nil million as of December 31, 2016).

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, 2017, we had not incurred any significant credit losses and had no significant amounts past due or impaired. At June 30, 2017, we had a credit risk concentration on one of our customers, Anadarko Energy Services Company, which owed us approximately $4 million and this amount represented greater than 10 percent of our trade accounts receivable.

Liquidity risk is the risk that the Partnership and our pipeline systems will not be able to meet our financial obligations as they become due. Our approach to managing liquidity risk is to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to our reputation. At June 30, 2017, the Partnership had a Senior Credit Facility of $500 million maturing in 2021 and the outstanding balance on this facility was $170 million. In addition, at June 30, 2017, Northern Border had a committed revolving bank line of $200 million maturing in 2020 with $181 million drawn and an additional $100 million 364-day revolving credit facility with no current borrowings. Both the Senior Credit Facility and the Northern Border $200 million credit facility have accordion features for additional capacity of $500 million and $100 million respectively, subject to lender consent.

Item 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

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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, 2017, 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, 2016.

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

A description of this legal proceeding can be found in Notes to Consolidated Financial Statements Note 15 Contingencies in Part I, Item 1, 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.

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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, 2016.

Following the closing of the 2017 Acquisition, we will not own a controlling interest in Iroquois, and we will be unable to cause certain actions to take place without the agreement of the other partners.

The major policies of Iroquois are established by its management committee, which consists of individuals who are designated by each of the partners and would include one individual designated by us. The management committee requires at least the affirmative vote of a majority of the partners percentage interests to take any action. Because of these provisions, without the concurrence of other partners, we would be unable to cause Iroquois to take or not to take certain actions, even though those actions may be in the best interests of the Partnership or Iroquois. Further, Iroquois may seek additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. In the event we elected not to, or were unable to, make a capital contribution to Iroquois; our ownership interest would be diluted.

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

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

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.

No.	Description
2.1	Agreement for Purchase and Sale of Partnership Interest in Iroquois Gas Transmission System, L.P. by and between TCPL Northeast Ltd. and TransCanada Iroquois Ltd., as Sellers and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 3, 2017 (Incorporated by reference from Exhibit 2.1 to TC PipeLines, LP s Form 8-K filed May 3, 2017).
2.1.1*	First Amendment to Purchase and Sale Agreement by and between TCPL Northeast Ltd. and TransCanada Iroquois Ltd., as Sellers and TC Pipelines Intermediate Limited Partnership as Buyer dated as of May 31, 2017.
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).
3.2	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*	Portland Natural Gas Transmission System Senior Secured Note Purchase Agreement dated as of April 10, 2003.
4.2*	Iroquois Gas Transmission, L.P.Senior Note Purchase Agreement dated as of May 13, 2009.
4.3*	Iroquois Gas Transmission, L.P.Senior Note Purchase Agreement dated as of April 27, 2010.
4.4*	Indenture dated as of May 30, 2000, between Iroquois Gas Transmission System, L.P. and The Chase Manhattan Bank.
4.4.1*	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).
4.5*	Credit Agreement dated as of June 26, 2008, between Iroquois Gas Transmission System, L.P. and JPMorgan Chase Bank, N.A. as administrative agent
4.5.1*	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
10.1*	Operating Agreement by and between Portland Natural Gas Transmission System and PNGTS Operating Co., LLC dated October 2, 1996

10.2*	Amended and Restated Operating Agreement by and between PNGTS Operating Co., LLC and 9207670 Delaware Inc. dated January 1, 2012.
10.3*	Amended and Restated Operating Agreement by and between PNGTS Operating Co., LLC and 1120436 Alberta Ltd., Inc. dated January 1, 2012
10.4*	Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated March 1, 1996
10.4.1*	First Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated May 23, 1996
10.4.2*	Second Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated October 23, 1996
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10.4.13*	Thirteenth Amendment to Portland Natural Gas Transmission System Amended and Restated Partnership Agreement dated June 1, 2017
10.5	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company by and between Northern Border Intermediate Limited Partnership and TC Pipelines Intermediate Limited Partnership dated April 6, 2006 (Incorporated by reference to Exhibit 3.1 to Northern Border Pipeline Company s Form 8-K filed on April 12, 2006).
10.6*	Third Amended and Restated Agreement of Limited Partnership Agreement of Iroquois Gas Transmission, L.P.
31.1*	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Transportation Term Sheet between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited (Incorporated by reference to Exhibit 99.3 to TC PipeLines, LP s Form 10-Q filed on May 4, 2017).
99.2*	Transportation Service Agreement FT-2010-001 between Portland Natural Gas Transmission System and TransCanada Energy Ltd., effective date July 01, 2010.
99.3*	Transportation Service Agreement FT18659 between Great Lakes Gas Transmission Limited Partnership and ANR Pipeline Company, effective date April 1, 2017.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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 3rd day of August 2017.

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

By:	/s/ Brandon Anderson Brandon Anderson President TC PipeLines GP, Inc. (Principal Executive Officer)
By:	/s/ Nathaniel A. Brown Nathaniel A. Brown Controller TC PipeLines GP, Inc. (Principal Financial Officer)

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101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.