TC PIPELINES LP
Form 10-Q
July 29, 2010

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, 2010

or

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

For the Transition period from _________ to _________

Commission File Number: 000-26091
TC PipeLines, LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	52-2135448 (I.R.S. Employer Identification Number)

717 Texas Street, Suite 2400 Houston, Texas (Address of principal executive offices)	77002-2761 (Zip code)

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

Indicate by check mark if 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 [ ]

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 [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer [X] Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company) Smaller reporting company [ ]

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

As of July 28, 2010, there were 46,227,766 of the registrant’s common units outstanding.

TC PIPELINES, LP

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

GLOSSARY

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

Alberta Hub	The grouping of gas gathering lines, processing, storage facilities in large scale and also a “liquid” pricing point recognized for trading in Alberta, Canada
ASC	Accounting Standards Codification
CAA	U.S. Environmental Protection Agency's Clean Air Act
Design capacity	Pipeline capacity available to transport natural gas based on system facilities and design conditions
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Gas exiting the WCSB	Net of the supply of and demand for natural gas in the WCSB region that is available for transportation to downstream markets; where supply represents WCSB production adjusted for injections into and withdrawals from WCSB storage
General Partner	TC PipeLines GP, Inc.
GL Rate Proceeding	FERC investigation into Great Lakes' rates pursuant to Section 5 of the NGA
GL Settlement	Stipulation and agreement approved by the FERC on July 15, 2010 establishing the terms pursuant to which all matters in the GL Rate Proceeding were resolved
Great Lakes	Great Lakes Gas Transmission Limited Partnership
IDR/IDRs	Incentive Distribution Rights
LIBOR	London Interbank Offered Rate
MDth/d	Thousand dekatherms per day
MMcf/d	Million cubic feet per day
NGA	Natural Gas Act
North Baja	North Baja Pipeline, LLC
Northern Border	Northern Border Pipeline Company
Other Pipes	North Baja and Tuscarora
Our pipeline systems	Great Lakes, Northern Border, North Baja and Tuscarora
Partnership	TC PipeLines, LP and its subsidiaries
Partnership Agreement	Second Amended and Restated Agreement of Limited Partnership
S&P	Standard & Poor's
SEC	Securities and Exchange Commission
Senior Credit Facility	TC PipeLines' revolving credit and term loan agreement
TransCanada	TransCanada Corporation and its subsidiaries
Tuscarora	Tuscarora Gas Transmission Company
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin
Yuma Lateral	An expansion of the North Baja pipeline from the Mexico/Arizona border to Yuma, Arizona

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF INCOME

(unaudited) (millions of dollars except per common unit amounts)	Three months ended June 30, 2010	Three months ended June 30, 2009(a)	Six months ended June 30, 2010	Six months ended June 30, 2009(a)
Equity income from investment in Great Lakes (Note 2)	13.1	12.9	29.4	32.4
Equity income from investment in Northern Border (Note 3)	12.2	5.4	26.8	21.0
Transmission revenues	17.0	16.8	34.4	33.6
Operating expenses	(3.3)	(2.8)	(6.7)	(5.7)
General and administrative	(1.1)	(2.9)	(2.4)	(4.1)
Depreciation	(3.7)	(3.7)	(7.4)	(7.3)
Financial charges, net and other	(6.5)	(7.8)	(12.7)	(16.1)
Net income	27.7	17.9	61.4	53.8
Net income allocation (Note 6)				
Common units	27.2	10.8	60.2	39.3
General partner	0.5	2.9	1.2	6.2
	27.7	13.7	61.4	45.5
Net income per common unit (Note 6)	$0.59	$0.31	$1.30	$1.13
Weighted average common units outstanding (millions)	46.2	34.9	46.2	34.9
Common units outstanding, end of the period (millions)	46.2	34.9	46.2	34.9

(a) Recast as discussed in Note 1.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(unaudited) (millions of dollars)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Net income(a)	27.7	17.9	61.4	53.8
Other comprehensive income/(loss)				
Change associated with hedging transactions (Note 10)	3.0	5.0	4.6	6.4
Change associated with hedging transactions of investees	-	0.3	-	0.2

	3.0	5.3	4.6	6.6
Total comprehensive income	30.7	23.2	66.0	60.4

(a) Recast as discussed in Note 1.

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

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEET

(unaudited)

(millions of dollars)	June 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	2.7	3.1
Accounts receivable and other (Note 11)	6.9	8.6
	9.6	11.7
Investment in Great Lakes (Note 2)	691.5	691.2
Investment in Northern Border (Note 3)	511.9	523.0
Plant, property and equipment		
(net of $125.2 accumulated depreciation; 2009 – $118.3)	319.6	318.0
Goodwill	130.2	130.2
Other assets	0.8	1.0
	1,663.6	1,675.1
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	4.5	4.5
Accrued interest	1.4	1.3
Current portion of long-term debt (Note 5)	51.6	53.4
Current portion of fair value of derivative contracts (Note 10)	13.4	12.9
	70.9	72.1
Long-term debt (Note 5)	485.5	487.9
Fair value of derivative contracts and other (Note 10)	6.6	11.6
	563.0	571.6
Partners' Equity		
Common units	1,098.3	1,105.6
General partner	23.4	23.6
Accumulated other comprehensive loss	(21.1)	(25.7)
	1,100.6	1,103.5
	1,663.6	1,675.1

Subsequent events (Note 12)

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

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CASH FLOWS

(unaudited) (millions of dollars)	Six months ended June 30, 2010	2009(a)
CASH GENERATED FROM OPERATIONS		
Net income	61.4	53.8
Depreciation	7.4	7.3
Amortization of other assets	0.2	0.3
Increase in long-term liabilities	0.1	0.2
Equity allowance for funds used during construction	(0.2)	(0.2)
Decrease/(increase) in operating working capital (Note 8)	1.8	(2.3)
	70.7	59.1
INVESTING ACTIVITIES		
Cumulative distributions in excess of equity earnings:		
Great Lakes	4.3	1.8
Northern Border	11.1	25.7
Investment in Great Lakes (Note 2)	(4.6)	-
Investment in Northern Border (Note 3)	-	(4.3)
Capital expenditures (Note 4)	(8.8)	(1.3)
	2.0	21.9
FINANCING ACTIVITIES		
Distributions paid (Note 7)	(68.9)	(55.5)
Long-term debt issued (Note 5)	12.0	-
Long-term debt repaid (Note 5)	(16.2)	(2.3)
Due to North Baja's former parent	-	(8.8)
	(73.1)	(66.6)
(Decrease)/increase in cash and cash equivalents	(0.4)	14.4
Cash and cash equivalents, beginning of period	3.1	8.4
Cash and cash equivalents, end of period	2.7	22.8
Interest payments made	5.2	11.1

(a) Recast as discussed in Note 1.

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

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

(unaudited)	Common Units		General Partner	Accumulated Other Comprehensive (Loss)/Income(a)	Partners' Equity	
	(millions of units)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of units)	(millions of dollars)
Partners' equity at December 31, 2009	46.2	1,105.6	23.6	(25.7)	46.2	1,103.5
Net income	-	60.2	1.2	-	-	61.4
Distributions paid	-	(67.5)	(1.4)	-	-	(68.9)
Other comprehensive income	-	-	-	4.6	-	4.6
Partners' equity at June 30, 2010	46.2	1,098.3	23.4	(21.1)	46.2	1,100.6

(a) The Partnership uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at June 30, 2010, the amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in the next 12 months is $13.4 million, which will be offset by a reduction to interest expense of a similar amount.

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

TC PIPELINES, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiaries are collectively referred to herein as “the Partnership.” In this report, references to “we,” “us” or “our” refer to the Partnership.

The preparation of financial statements in conformity with United States of America (U.S.) generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at 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. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and include all adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the financial results for the interim periods presented.

The results of operations for the three and six months ended June 30, 2010 and 2009 are not necessarily indicative of the results that may be expected for a full fiscal year. The unaudited interim financial statements should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2009. Our significant accounting policies are consistent with those disclosed in Note 2 of the financial statements in our Annual Report on Form 10-K for the year ended December 31, 2009.

On July 1, 2009, the Partnership acquired a 100 per cent interest in North Baja Pipeline, LLC (North Baja), a Delaware limited liability company, from a wholly-owned subsidiary of TransCanada Corporation. TransCanada Corporation and its subsidiaries are herein collectively referred to as “TransCanada.” Because North Baja was acquired from TransCanada, the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada’s carrying value and the Partnership’s historical financial information was recast to include the acquired entity for all periods presented. The effect of recasting the Partnership’s consolidated financial statements to account for the common control transaction increased the Partnership’s net income by $4.2 million and $8.3 million, respectively, for the three and six months ended June 30, 2009 from amounts previously reported.

NOTE 2 INVESTMENT IN GREAT LAKES

We own a 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). Great Lakes is regulated by the Federal Energy Regulatory Commission (FERC) and is operated by TransCanada.

We use the equity method of accounting for our interest in Great Lakes. Great Lakes had no undistributed earnings for the six months ended June 30, 2010 and 2009.

On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 (November 2009 Order) instituting an investigation pursuant to Section 5 of the Natural Gas Act (GL Rate Proceeding). The FERC alleged, based on a review of certain historical information, that Great Lakes’ revenues might substantially exceed Great Lakes’ actual cost of service and therefore may be unjust and unreasonable. On February 4, 2010, Great Lakes filed a cost and revenue study in response to the November 2009 Order.

As a result of extensive settlement negotiations, on May 21, 2010, Great Lakes filed a stipulation and agreement (the GL Settlement) establishing the terms pursuant to which all matters in the GL Rate Proceeding would be resolved. On

June 17, 2010, the Administrative Law Judge certified the GL Settlement as uncontested to the FERC for its approval. On July 15, 2010, the FERC approved the GL Settlement without modification. The settlement was reached among Great Lakes, active participants and the FERC trial staff. As approved, the GL Settlement will apply to all current and future shippers on Great Lakes' system. The GL Settlement did not have a material impact on the Partnership's earnings and cash flows for the three and six months ended June 30, 2010.

Under the terms of the GL Settlement, reservation rates on Great Lakes' pipeline system were reduced by eight per cent, effective May 1, 2010. In addition, depreciation expense for Great Lakes' transmission plant decreased from 2.75 per cent to 1.48 per cent per year. Other depreciation rates for the plant either decreased or remained unchanged. Long-haul reservation rates from Great Lakes' western zone to its eastern zone declined by eight per cent from $0.338 per dekatherm to $0.311 per dekatherm and various short-haul firm paths experienced similar reductions. Rates for interruptible transportation service are derived on a 100 per cent load factor basis of firm transportation rates, effective June 1, 2010. All other terms of the settlement were effective May 1, 2010.

Great Lakes' obligation to share interruptible transportation revenues as established under the September 24, 1992 Stipulation and Agreement in Partial Settlement of Rate Proceedings in FERC Docket No. RP91-143 was eliminated under the GL Settlement, effective May 1, 2010. On July 1, 2010, Great Lakes paid out the interruptible transportation revenue sharing accumulated prior to May 1, 2010 and filed its final interruptible transportation revenue sharing report with the FERC in Docket No. RP91-143-061. Under the GL Settlement, Great Lakes has agreed to a new revenue sharing provision with respect to revenues, both firm and interruptible, it receives in excess of $500 million during the period between November 1, 2010 and October 31, 2012. Great Lakes will share with qualifying shippers 50 per cent of any qualifying revenues collected during this period in excess of the $500 million threshold.

The GL Settlement rates will remain in effect through at least November 30, 2011. The GL Settlement includes a moratorium on participants and customers filing any Natural Gas Act (NGA) Section 5 rate case to place new rates into effect prior to November 1, 2012. There is also a moratorium on Great Lakes filing a general NGA Section 4 rate case prior to June 1, 2011 to place new rates into effect prior to December 1, 2011. These moratoria are subject to conditions detailed in the GL Settlement. In addition, the GL Settlement requires Great Lakes to file a NGA Section 4 general rate case no later than November 1, 2013.

On June 30, 2010, the Partnership made an equity contribution of $2.3 million to Great Lakes, representing the Partnership's second and final installment of its 46.45 per cent share of a $10.0 million cash call issued by Great Lakes to expand backhaul capacity from St. Clair to Emerson. The first installment of $2.3 million was paid in the first quarter of 2010.

The following tables contain summarized financial information of Great Lakes:

Summarized Consolidated Great Lakes Balance Sheet

(unaudited) (millions of dollars)	June 30, 2010	December 31, 2009
Assets		
Cash and cash equivalents	-	0.1
Other current assets	87.6	83.0
Plant, property and equipment, net	852.7	873.3
	940.3	956.4
Liabilities and Partners' Equity		
Current liabilities	31.7	40.3
Deferred credits	4.5	3.8
Long-term debt, including current maturities	402.0	411.0
Partners' capital	502.1	501.3
	940.3	956.4

Summarized Consolidated Great Lakes Income Statement

(unaudited) (millions of dollars)	Three months ended June 30, 2010	2009	Six months ended June 30, 2010	2009
Transmission revenues	62.9	69.0	135.8	151.5
Operating expenses	(15.6)	(17.1)	(29.8)	(33.1)
Depreciation	(10.1)	(14.6)	(24.4)	(29.2)
Financial charges, net and other	(7.7)	(8.1)	(15.6)	(16.3)
Michigan business tax	(1.2)	(1.3)	(2.7)	(3.1)
Net income	28.3	27.9	63.3	69.8

NOTE 3 INVESTMENT IN NORTHERN BORDER

We own a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border). Northern Border is regulated by the FERC and is operated by TransCanada.

We use the equity method of accounting for our interest in Northern Border. Northern Border had no undistributed earnings for the six months ended June 30, 2010 and 2009.

The following tables contain summarized financial information of Northern Border:

Summarized Northern Border Balance Sheet

(unaudited) (millions of dollars)	June 30, 2010	December 31, 2009
Assets		
Cash and cash equivalents	3.4	16.9
Other current assets	31.5	30.2
Plant, property and equipment, net	1,315.9	1,343.1
Other assets	23.8	24.2
	1,374.6	1,414.4
Liabilities and Partners' Equity		
Current liabilities	40.2	38.0
Deferred credits and other	11.4	8.3
Long-term debt, including current maturities	540.6	564.6
Partners' equity		
Partners' capital	785.4	806.6
Accumulated other comprehensive loss	(3.0)	(3.1)
	1,374.6	1,414.4

Summarized Northern Border Income Statement

(unaudited) (millions of dollars)	Three months ended June 30, 2010	2009	Six months ended June 30, 2010	2009
Transmission revenues	65.8	54.2	134.9	128.7
Operating expenses	(19.7)	(18.3)	(37.7)	(36.8)
Depreciation	(15.4)	(15.5)	(30.8)	(30.8)
Financial charges, net and other	(6.0)	(9.2)	(12.0)	(18.3)

Net income	24.7	11.2	54.4	42.8

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NOTE 4 ASSET ACQUISITIONS

Yuma Lateral Asset Purchase

At the time of the July 1, 2009 acquisition of North Baja from TransCanada, TransCanada had begun an expansion project of the North Baja pipeline from the Mexico/Arizona border to Yuma, Arizona (Yuma Lateral). The Partnership agreed to acquire the expansion facilities and contracts for an additional sum up to $10.0 million, if TransCanada completed the project by June 30, 2010. On March 5, 2010, the Partnership acquired the expansion facilities and contracts in place at that time for a purchase price of $7.6 million. The Yuma Lateral was placed into service on March 13, 2010. The North Baja acquisition agreement provided that an additional payment of up to $2.4 million be made to TransCanada in the event that any other shippers contracted for services on the Yuma Lateral before June 30, 2010. A potential shipper signed a precedent agreement with North Baja on June 29, 2010 to enter into agreements for service on the Yuma Lateral. An amendment to the acquisition agreement between the Partnership and TransCanada was entered into on June 29, 2010 to allow TransCanada to continue to pursue additional contracts until December 31, 2010 and, as a result, receive an additional payment of up to $2.4 million.

The Yuma Lateral asset purchase was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets acquired were recorded at TransCanada's carrying value. As the fair value paid for the Yuma Lateral assets of $7.6 million was greater than the $6.1 million recorded as Plant, property and equipment, the excess purchase price paid of $1.5 million was recorded as a reduction to Partners' Equity. In the second quarter, $1.5 million of additional construction costs were incurred by TransCanada to complete the Yuma Lateral. These costs were recorded by North Baja as Plant, property and equipment and a contribution of capital from TransCanada, thereby reducing the excess purchase price paid by the Partnership from $1.5 million to $nil.

NOTE 5 CREDIT FACILITIES AND LONG-TERM DEBT

(unaudited) (millions of dollars)	June 30, 2010	December 31, 2009
Senior Credit Facility due 2011	482.0	484.0
7.13% Series A Senior Notes due 2010	46.7	48.2
7.99% Series B Senior Notes due 2010	4.1	4.4
6.89% Series C Senior Notes due 2012	4.3	4.7
	537.1	541.3
Less: current portion of long-term debt	51.6	53.4
	485.5	487.9

The Partnership's Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility, maturing December 2011. At June 30, 2010, there was $7.0 million drawn under the senior revolving credit facility (2009 – $nil). The interest rate on the Senior Credit Facility averaged 0.9 per cent for the three and six months ended June 30, 2010 (2009 – 1.7 per cent and 2.0 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.2 per cent for the three and six months ended June 30, 2010 (2009 – 4.8 per cent and 4.9 per cent). Prior to hedging activities, the interest rate was 1.1 per cent at June 30, 2010 (2009 – 1.2 per cent). At June 30, 2010, the Partnership was in compliance with its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders.

The principal repayments required on our long-term debt are as follows:

(unaudited) (millions of dollars)	
2010	51.6
2011	482.0
2012	3.5
	537.1

On April 22, 2010, the Partnership filed an automatic universal shelf registration statement on Form S-3 (ASR) with the Securities and Exchange Commission, which replaced the universal shelf registration filed in December 2008. The ASR will allow the Partnership to issue an indeterminate amount of securities of the Partnership, including both senior and subordinated debt securities and/or common units representing limited partnership interests in the Partnership. The ASR was effective immediately upon filing and will expire April 22, 2013.

NOTE 6 NET INCOME PER COMMON UNIT

Net income per common unit is computed by dividing net income, after deduction of the general partner's allocation, by the weighted average number of common units outstanding. The general partner's allocation is equal to an amount based upon the general partner's two per cent 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.

Net income per common unit was determined as follows:

(unaudited) (millions of dollars except per common unit amounts)	Three months ended June 30, 2010	 2009	Six months ended June 30, 2010	 2009
Net income(a)	27.7	17.9	61.4	53.8
North Baja's contribution prior to acquisition	-	(4.2)	-	(8.3)
Net income allocated to partners(b)	27.7	13.7	61.4	45.5
Net income allocated to general partner:				
General partner interest	(0.5)	(0.3)	(1.2)	(0.9)
Incentive distribution income allocation	-	(2.6)	-	(5.3)
	(0.5)	(2.9)	(1.2)	(6.2)
Net income allocable to common units	27.2	10.8	60.2	39.3
Weighted average common units outstanding (millions)	46.2	34.9	46.2	34.9
Net income per common unit	$0.59	$0.31	$1.30	$1.13

(a) Recast as discussed in Note 1.

(b) Net income allocated to partners excludes North Baja's earnings prior to the Partnership's acquisition of North Baja on July 1, 2009, as the earnings of North Baja prior to that date were allocated to TransCanada and were not allocable to either the general partner or common units.

NOTE 7 CASH DISTRIBUTIONS

For the three and six months ended June 30, 2010, the Partnership distributed $0.73 and $1.46 per common unit (2009 – $0.705 and $1.41 per common unit). The distributions paid for the three and six months ended June 30, 2010 included incentive distributions to the general partner in the amount of $nil (2009 – $2.6 million and $5.3 million).

NOTE 8 CHANGE IN WORKING CAPITAL

(unaudited) (millions of dollars)	Six months ended June 30, 2010	 2009(a)
Decrease in accounts receivable and other	1.7	1.4
Decrease in accounts payable and accrued liabilities	-	(3.0)
Increase/(decrease) in accrued interest	0.1	(0.7)
Decrease/(increase) in operating working capital	1.8	(2.3)

(a) Recast as discussed in Note 1.

NOTE 9 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $0.5 million and $1.0 million for the three and six months ended June 30, 2010 (2009 – $0.5 million and $0.9 million).

As operator, TransCanada and its affiliates provide capital and operating services to Great Lakes, Northern Border, North Baja and Tuscarora (together, “our pipeline systems”). TransCanada and its affiliates incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, and property and liability insurance costs.

Costs charged to our pipeline systems for the three and six months ended June 30, 2010 and 2009 by TransCanada and its affiliates, and amounts payable to TransCanada and its affiliates at June 30, 2010 and December 31, 2009, are summarized in the following tables:

(unaudited) (millions of dollars)	Three months ended June 30, 2010	2009	Six months ended June 30, 2010	2009
Costs charged by TransCanada and its affiliates:				
Great Lakes	8.2	8.2	15.8	15.5
Northern Border	7.7	6.4	14.6	12.7
North Baja(a)	0.7	0.8	1.5	1.6
Tuscarora	1.0	0.8	1.9	1.5
Impact on the Partnership's net income:				
Great Lakes	3.5	3.7	6.9	6.9
Northern Border	3.4	3.1	6.6	6.0
North Baja(a)	0.7	0.7	1.4	1.3
Tuscarora	0.9	0.7	1.8	1.4

(unaudited) (millions of dollars)	June 30, 2010	December 31, 2009
Amount payable to TransCanada and its affiliates for costs charged in the period:		
Great Lakes	3.5	6.6
Northern Border	2.9	2.6
North Baja	0.2	0.4
Tuscarora	0.6	0.6

(a) Recast as discussed in Note 1.

Great Lakes earns transportation revenues from TransCanada and its affiliates under contracts with fixed prices relative to the recourse rate. The contracts have remaining terms ranging from one to eight years, the weighted average being 2.4 years. Great Lakes earned $40.4 million and $80.4 million of transportation revenues under these contracts for the three and six months ended June 30, 2010 (2009 – $35.1 million and $72.4 million). These amounts represent 64.2 per cent and 59.2 per cent of total revenues earned by Great Lakes for the three and six months ended June 30, 2010 (2009 – 50.9 per cent and 47.8 per cent).

Revenue from TransCanada and its affiliates of $18.8 million and $37.3 million are included in the Partnership's equity income from Great Lakes for the three and six months ended June 30, 2010 (2009 – $16.3 million and $33.6 million). At June 30, 2010, $13.6 million was included in Great Lakes' receivables for transportation contracts with TransCanada and its affiliates (December 31, 2009 – $12.9 million).

NOTE 10 DERIVATIVE FINANCIAL INSTRUMENTS

The carrying value of cash and cash equivalents, accounts receivable and other, accounts payable and accrued liabilities, and accrued interest approximate their fair values because of the short maturity or duration of these instruments, or because the instruments carry a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership's long-term debt is estimated by discounting the future cash flows of each instrument at estimated current borrowing rates.

The 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.

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at June 30, 2010 (December 31, 2009 – $375.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap through February 28, 2011, where the fixed interest rate paid is 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility.

Financial instruments are recorded at fair value on a recurring basis and are categorized into one of three categories based upon a fair value hierarchy. The Partnership has classified its derivative financial instruments as Level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At June 30, 2010, the fair value of the interest rate swaps accounted for as hedges was negative $19.3 million (December 31, 2009 – negative $23.8 million), of which $13.4 million is classified as a current liability (December 31, 2009 – $12.9 million). The fair value of the interest rate swaps was calculated using the period-end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. For the three and six months ended June 30, 2010, the Partnership recorded interest expense of $4.1 million and $8.3 million on the interest rate swaps and options (2009 – $3.7 million and $6.9 million).

NOTE 11 ACCOUNTS RECEIVABLE AND OTHER

(unaudited) (millions of dollars)	June 30, 2010	December 31, 2009
Accounts receivable	6.0	7.4
Inventory	0.6	0.6
Prepayments	0.3	0.5
Other assets	-	0.1
	6.9	8.6

NOTE 12 SUBSEQUENT EVENTS

On July 20, 2010, the Partnership announced that the board of directors of the general partner declared the Partnership’s second quarter 2010 cash distribution in the amount of $0.73 per common unit, payable on August 13, 2010 to unitholders of record as of the close of business on July 31, 2010.

Great Lakes declared and will pay its second quarter distribution of $37.5 million on August 2, 2010, of which the Partnership will receive its 46.45 per cent share or $17.4 million.

Northern Border declared and will pay its second quarter distribution of $39.8 million on August 2, 2010, of which the Partnership will receive its 50 per cent share or $19.9 million.

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

The following discusses the results of operations and liquidity and capital resources of TC PipeLines, LP (the Partnership), along with those of our pipeline systems. We use "our pipeline systems" when referring to the Partnership's ownership interests in Great Lakes Gas Transmission Limited Partnership (Great Lakes), Northern Border Pipeline Company (Northern Border), North Baja Pipeline, LLC (North Baja) and Tuscarora Gas Transmission Company (Tuscarora).

FORWARD-LOOKING STATEMENTS

The statements in this report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "forecast" and other words and terms of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking.

Forward-looking statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions, although no assurance can be given that these views will prove to be correct. Certain factors that could cause actual results to differ materially from those contemplated in the forward-looking statements include:

- changes in the ability of Great Lakes and Northern Border to continue to make distributions and North Baja and Tuscarora to continue to generate positive operating cash flows at their current levels;
- the impact of unsold capacity on Great Lakes and Northern Border being greater or less than expected;
- competitive conditions in our industry and the ability of our pipeline systems to market pipeline capacity on favorable terms, which is affected by:
  - o future demand for and prices of natural gas;
  - o level of natural gas basis differentials;
  - o competitive conditions in the overall natural gas and electricity markets;
  - o availability and relative cost of supplies of Canadian and United States (U.S.) natural gas, including the shale gas resources such as the Horn River and Montney deposits in Western Canada, along with U.S. Rockies, Mid-Continent, and Marcellus gas developments;
  - o competitive developments by U.S. and Canadian natural gas transmission companies;
  - o the availability of additional storage capacity and current storage levels;
  - o the level of liquefied natural gas imports;
  - o weather conditions that impact supply and demand; and
  - o the ability of shippers to meet creditworthiness requirements;
- the impact of current and future laws, rulings and governmental regulations, particularly Federal Energy Regulatory Commission (FERC) regulations and rate proceedings, and proposed and pending legislation by Congress, and proposed and pending regulations by the U.S. Environmental Protection Agency (EPA), including the new Tailoring Rule, on us and our pipeline systems;
- changes in relative cost structures of natural gas producing basins, such as changes in royalty programs, that may impact the development of the Western Canada Sedimentary Basin (WCSB);
- decisions by other pipeline companies to advance projects that will affect our pipeline systems and the regulatory, financing and construction risks related to construction of interstate natural gas pipelines and additional facilities;
- the ability of our pipeline systems to identify and/or consummate expansion projects that are accretive growth opportunities for the Partnership;
- the performance of contractual obligations by customers of our pipeline systems;
- the imposition of entity level taxation by states on partnerships;

operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- the Partnership's ability to identify and/or consummate accretive growth opportunities from TransCanada Corporation or others;
- our ability to control operating costs and the ability of TransCanada Corporation to complete its reorganization of U.S. pipeline operations, including the operations of our pipeline systems, and realize cost savings; and
- general economic conditions in North America, which impact:
  - o the debt and equity capital markets and our ability to access these markets at reasonable costs;
  - o the overall demand for natural gas by end users; and
  - o natural gas prices.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. Forward-looking statements are also affected by the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2009 and those set forth from time to time in our filings with the Securities and Exchange Commission (SEC), which are available through our website at www.tcpipelines.com and through the SEC's website at www.sec.gov. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report. All forward-looking statements and information included in this report are based on information available to us on the date of this report, and except as required by applicable law, we undertake no obligation to update publicly or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

The following discussion and analysis should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2009 and the unaudited financial statements and notes included in Item 1. "Financial Statements" of this Quarterly Report on Form 10-Q. All amounts are stated in U.S. dollars.

PARTNERSHIP OVERVIEW

We are a publicly traded Delaware limited partnership formed in 1998 by TransCanada PipeLines Limited to acquire, own and participate in the management of energy infrastructure businesses in North America. Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

TC PipeLines, LP and its subsidiaries are collectively referred to herein as "the Partnership." In this report, references to "we," "us" or "our" refer to the Partnership. TransCanada PipeLines Limited is a wholly-owned subsidiary of TransCanada Corporation (which, together with its subsidiaries, is referred to as TransCanada).
The general partner of the Partnership is TC PipeLines GP, Inc., a wholly-owned subsidiary of TransCanada.

To date, our investments have been in interstate natural gas pipeline systems that transport natural gas to a variety of markets in the U. S., Eastern Canada and Mexico. Our pipeline systems derive their operating revenue from the transportation of natural gas. They are regulated by the FERC and are operated by TransCanada. Our investments are summarized in the following table:

	Ownership Percentage	Ownership Date Acquired	System Specifications Length (Miles)	System Specifications Capacity (MMcf/d)
Great Lakes	46.45	February 2007	2,115	2,400 (summer design) 2,500 (winter design)
Northern Border	30.00 20.00 50.00	May 1999 April 2006	1,249	2,400 (design)
North Baja	100.00	July 2009	80	500 (FERC licensed southbound) 600 (northbound design)
Tuscarora	49.00 49.00 2.00 100.00	September 2000 December 2006 December 2007	240	230 (design)

RECENT DEVELOPMENTS

Partnership

Yuma Lateral Expansion Acquisition

At the time of our July 1, 2009 acquisition of North Baja from TransCanada, TransCanada had begun a project to expand the North Baja pipeline from the Mexico/Arizona border to Yuma, Arizona (Yuma Lateral). We agreed to acquire the expansion facilities and contracts for an additional sum of up to $10.0 million, if TransCanada completed the project by June 30, 2010. On March 5, 2010, we acquired the expansion facilities and contracts in place at that time for a purchase price of $7.6 million. The North Baja acquisition agreement provided that an additional payment of up to $2.4 million be made to TransCanada in the event that any other shippers contracted for services on the Yuma Lateral before June 30, 2010. A potential shipper signed a precedent agreement with North Baja on June 29, 2010 to enter into agreements for service on the Yuma Lateral. An amendment to the acquisition agreement between the Partnership and TransCanada was entered into on June 29, 2010 to allow TransCanada to continue to pursue additional contracts until December 31, 2010 and, as a result, receive an additional payment of up to $2.4 million.

Our Pipeline Systems

Great Lakes Rate Proceeding

Following extensive settlement negotiations, on May 21, 2010, Great Lakes filed a stipulation and agreement embodying the terms of a settlement reached among Great Lakes, active participants and the FERC trial staff (GL Settlement) with respect to its Natural Gas Act (NGA) Section 5 Rate Proceeding (GL Rate Proceeding). On July 15, 2010, the FERC approved the GL Settlement without modification. As approved, the GL Settlement will apply to all current and future shippers on Great Lakes' system. See "Factors that Impact the Business of Our Pipeline Systems-Government Regulation" for more information with respect to the GL Settlement.

FACTORS THAT IMPACT OUR BUSINESS

Our general partner interests in Great Lakes and Northern Border, and our ownership of North Baja and Tuscarora represent our only material assets at June 30, 2010. As a result, we are dependent upon our pipeline systems for our results of operations and all of our available cash. Key factors that impact our business are the cash flows received from our investments and our ability to maintain a strong and balanced financial position. These factors determine our ability to maintain a prudent level of available cash to make distributions to our unitholders, fund future growth, and broaden our asset base in a disciplined and focused manner. Cash flows from our investments are dependent upon the ability of Great Lakes and Northern Border to make distributions to us and of North Baja and Tuscarora to generate positive operating cash flows.

We believe our strong financial position, including available unused capacity on our credit facility, gives us the capacity to pursue opportunities to grow in a sustained and disciplined manner for the long-term benefit of our unitholders.

FACTORS THAT IMPACT THE BUSINESS OF OUR PIPELINE SYSTEMS

Our pipeline systems provide natural gas transportation services to their customers. Key factors that impact the business of our pipeline systems are the level of capacity under firm contracts and related terms, supply of and demand for natural gas in the markets in which our pipeline systems operate, competition, and customers and the mix of services they require. Government regulation of natural gas pipelines is also a major factor impacting the business of our pipeline systems. Government regulation of natural gas pipelines includes, among others, regulation of the terms of and rates for interstate natural gas transportation services, environmental issues, and pipeline safety and integrity. These factors are discussed in more detail below.

Substantially all of the services provided by our pipeline systems are through firm service transportation contracts with a reservation charge to reserve pipeline capacity, regardless of use, for the term of the contract. Contract terms can range from short term (contracts with a duration up to and including one year) to long term (contracts with a duration greater than one year). Over the term of the firm service transportation contracts, the revenues associated with capacity under the contracts are not subject to fluctuations caused by changing supply and demand conditions, competition, and customers.

The following table provides information for our pipeline systems as at July 1, 2010 with respect to the proportion of capacity subscribed under long-term firm contracts and their weighted average remaining contract life as well as the proportion of capacity subscribed under short-term firm contracts. Our North Baja and Tuscarora pipeline systems have little risk of fluctuations in revenues as a result of their strong contracted capacity position under long-term contracts.

		As at July 1, 2010		
		Long-Term Contracts (a)		Short-Term Contracts(b)
	Our Ownership Interest	Firm Contracted Capacity(c)	Weighted Average Remaining Contract Life (in Years)(d)	Firm Contracted Capacity (c)
Great Lakes	46.45%	90%	1.8	7%

Northern Border	50%	41%	3.1	59%
North Baja	100%	(e) 81% southbound 60% northbound	15.9	0%
Tuscarora	100%	97%	10.2	0%

(a) Capacity contracted under long-term contracts includes all capacity that was contracted for terms greater than one year.

(b) Capacity contracted under short-term contracts includes all capacity that was contracted for terms up to and including one year.

(c) Firm contracted capacity is calculated based upon contracted capacity compared to design capacity for Northern Border, Tuscarora and North Baja northbound transportation; compared to average design capacity for Great Lakes; and compared to FERC licensed capacity for North Baja southbound transportation.

(d) Weighted average remaining contract life is weighted based upon maximum daily quantity in the contracts.

(e) Due to North Baja's bi-directional nature, it can contract for both southbound and northbound capacity separately.

Natural Gas Supply and Demand

While the ongoing impacts of decreased demand for natural gas in North America related to the economic environment, increased production from U.S. shale gas developments and high levels of natural gas in storage continued to hold commodity prices for natural gas at low levels over the second quarter, they increased slightly as compared to the second quarter of 2009. We expect the pressures on natural gas commodity prices to continue through the remainder of 2010.

The primary source of natural gas transported by our pipeline systems, excluding North Baja, is the WCSB. "Gas exiting the WCSB" is the term we use to represent the net of the supply of and demand for natural gas in the WCSB region. It is dependent upon WCSB natural gas production levels, demand for natural gas in Western Canada, and natural gas storage capacity and demand for natural gas storage injection in Western Canada. The volume of gas exiting the WCSB was slightly lower in the second quarter of 2010 compared to the same period in 2009, due mainly to decreased production, which was largely offset by reduced WCSB storage injections. WCSB production is expected to continue near current levels through the remainder of 2010.

Factors that may support increased WCSB production in the future include strengthening gas prices and reduced royalty costs, which would support exploration and development of new fields in Western Canada. Drilling in the WCSB is expected to recover when gas prices stabilize and exploration and development costs become more economical through factors such as more efficient and productive drilling. Over the long term, we expect WCSB natural gas producers will direct significant resources toward development of unconventional resources such as shale gas and coalbed methane. Additional natural gas supply from the Alberta Hub is expected to be available in the future when new pipeline projects associated with the Montney and Horn River shale gas regions in Western Canada are constructed, or if the longer term potential associated with the North Slope in Alaska and the proposed development of the Mackenzie Delta in Northern Canada is realized.

Levels of Western Canadian natural gas in storage and U.S. working gas storage levels at the end of the second quarter of 2010 continued to be above five-year average levels. The high demand period for storage injection usually begins in the spring and extends through most of the summer. However, high levels of gas already in storage contributed to lower storage injections in Western Canada in the second quarter of 2010 relative to the same period in 2009, which largely offset the impact of decreased production so that volumes of gas exiting the WCSB were only slightly lower. High levels of natural gas already in storage in the market regions served by our pipeline systems are expected to reduce demand for transportation services related to storage injection during the remainder of 2010. High overall storage levels have a dampening effect on natural gas prices, which in turn contributes to reduced production.

Continued strengthening of the North American economy and decreased natural gas inventories resulting from reduced production levels and seasonal weather related demand would positively affect natural gas prices.

North America's demand for natural gas is expected to rise as the economy returns to growth mode. The relative environmental merits of natural gas versus other carbon-based forms of energy are also expected to increase the demand for natural gas in the longer term.

U.S. natural gas production in the second quarter of 2010 slightly increased over the first quarter of 2010, mainly due to continued drilling to develop unconventional resources. Production from natural gas basins other than the WCSB represents supply competition for WCSB natural gas. Overall, U.S. natural gas production is expected to increase slightly for the 2010 year compared to recent years. Production from individual natural gas basins in North America will depend on factors that include natural gas drilling activity, well production rates, and relative operating costs.

Demand for Transportation Services and Contracting

Demand for natural gas transportation service on our pipeline systems is directly related to the activity in the natural gas markets served by these systems. Factors that may impact demand for transportation service on any one system include weather in the market area, the availability of natural gas supply at the pipeline system's receipt points, the ability and willingness of natural gas shippers to utilize that system over alternative pipelines, relative transportation rates, and the volume of natural gas delivered to markets supplied by that system from other supply sources and storage facilities. The impact of changes in demand for natural gas transportation services on operating revenues for our pipeline systems is dependent upon the extent to which capacity has been contracted under long-term firm contracts. Contracted capacity and system throughput are measures of demand for natural gas transportation services.

The reduced level of gas exiting the WCSB has resulted in excess pipeline capacity serving the WCSB. We anticipate there will be excess natural gas pipeline capacity serving the WCSB for the foreseeable future and therefore competition for gas exiting the WCSB will continue. In this environment, there is little incentive for shippers to make long-term commitments for capacity and the trend towards shorter term contracts is expected to continue for Great Lakes and Northern Border. As a result, there may be increased volatility and seasonality with respect to throughput and revenues for these pipelines.

Great Lakes

Great Lakes' average contracted capacity was 93 per cent of its average design capacity for the second quarter of 2010, compared to 97 per cent in the second quarter of 2009. As at July 1, 2010, Great Lakes' average design capacity was contracted on a firm basis as follows: 90 per cent under long-term contracts with a weighted average remaining contract life of 1.8 years and seven per cent under short-term contracts. In the absence of additional new contracting, beginning November 1, 2010, the average design capacity contracted on a firm basis under long-term contracts will decrease to 69 per cent as a result of contract expiries. Great Lakes' revenue may decline beginning November 1, 2010 if it is required to discount rates to recontract or is unable to recontract its expiring capacity.

Throughput on Great Lakes' pipeline system for the second quarter of 2010 increased to 2,130 MMcf/d compared to 2,053 MMcf/d for the same period in 2009 primarily due to increased utilization of long-term firm contracts partially offset by reduced sales of short-term transportation services due to lower capacity available for short-term services combined with lower transportation values compared to the same period in 2009. Increases in throughput related to utilization of long-term firm contracts have a minimal impact on revenue earned from these contracts. When the level of long-term firm contracts decreases beginning in November 2010, Great Lakes may experience increased volatility in revenues as a result of changes in throughput. Great Lakes is expected to continue discounting its transportation capacity as needed to optimize revenue.

Prevailing market conditions and dynamic competitive factors in North America, particularly reduced gas exiting the WCSB, increased supply from other supply basins to our pipeline systems' market areas, and the economic environment affecting the demand for natural gas, have reduced Great Lakes' ability to market available capacity at historic transportation rates. We expect the downward pressure on transportation values to continue through the remainder of 2010.

Northern Border

Northern Border's average contracted capacity was 95 per cent of its design capacity for the second quarter of 2010, compared to 56 per cent for the second quarter of 2009. Northern Border's ability to contract upstream capacity was positively impacted during the second quarter by reduced deliveries of natural gas to Midwest markets from other supply sources which resulted in increased transportation values on the eastern leg of the Northern Border system into Chicago. As well, Northern Border benefited due to its lower cost of transportation relative to its competition for gas exiting the WCSB.

Throughput on Northern Border's pipeline system in the second quarter of 2010 was 2,462 MMcf/d compared to 1,724 MMcf/d in the second quarter of 2009. The increased throughput was primarily due to increased transportation values for services on Northern Border. Northern Border continued to discount transportation capacity in the second quarter of 2010 and expects to continue discounting available transportation capacity as needed to optimize revenue. As at July 1, 2010, Northern Border's design capacity was contracted on a firm basis as follows: 41 per cent under long-term contracts with a weighted average remaining life of 3.1 years and 59 per cent under short-term contracts. Northern Border is fully contracted through the end of October 2010.

TransCanada's Bison Pipeline will extend from the Powder River Basin producing region in Wyoming to an interconnection with the Northern Border system in Morton County, North Dakota. TransCanada expects the project to be placed into service in the fourth quarter of 2010. When completed, this project will increase Northern Border's supply diversity as the interconnection will provide access to a new competitively-priced natural gas supply source for Northern Border's shippers. Over the long term, this should enhance utilization of Northern Border's pipeline system. Shippers on the Bison Pipeline have executed 10 year contracts for approximately 407 MMcf/d of capacity on the Northern Border system from Port of Morgan, Montana to Ventura, Iowa, commencing on the in-service date of the Bison Pipeline. When the Bison Pipeline is completed, this will increase Northern Border's average contracted capacity and weighted average contract life. We expect that some or all of the volumes from the Bison Pipeline may displace existing shipments from the WCSB. As such, any impact to Northern Border's revenues will be dependent upon the overall demand for transportation to the markets served by Northern Border.

Competition

There is currently competition among natural gas pipelines for gas exiting the WCSB due to excess pipeline capacity. Factors impacting the competition for gas exiting the WCSB include levels of firm transportation contracts on each pipeline, demand for natural gas in the regions served by each pipeline, and relative transportation values on each pipeline, which are impacted by their transportation rates. Currently, factors impacting the competition for gas exiting the WCSB include high natural gas storage levels in Eastern Canada, Michigan and California, as well as changes in basis differential for each of the pipelines accessing the WCSB resulting from new pipeline infrastructure placed into service over the past two years.

Our pipeline systems compete primarily with other interstate and intrastate pipelines in the transportation of natural gas. Competition among natural gas pipelines is based primarily on transportation charges and proximity to natural gas supply areas and markets. Growth in supplies available from other natural gas producing regions has impacted prices for natural gas delivered to some of the markets our pipeline systems serve relative to other market regions. Increased competition within the North American natural gas industry has resulted in a trend towards shorter term contracting as customers assess and choose the markets that optimize their netback prices.

There was a reduction in supply competition in the Midwest markets served by Northern Border that increased demand for Northern Border's transportation services in the second quarter of 2010. With the completion of the Rockies Express Pipeline, deliveries moved further east out of Northern Border's market areas. As well, deliveries from other supply sources via interconnecting pipelines decreased.

Government Regulation

Great Lakes Rate Proceeding – On November 19, 2009, the FERC issued an order in FERC Docket No. RP10-149 instituting an investigation pursuant to Section 5 of the NGA. The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable. On February 4, 2010, Great Lakes filed a cost and revenue study in response to the November 2009 Order.

As a result of extensive settlement negotiations, on May 21, 2010, Great Lakes filed the GL Settlement establishing the terms pursuant to which all matters in the GL Rate Proceeding would be resolved. On June 17, 2010, the Administrative Law Judge certified the GL Settlement as uncontested to the FERC for its approval. On July 15, 2010, the FERC approved the GL Settlement without modification. The GL Settlement was reached among Great Lakes, active participants and the FERC trial staff. As approved, the GL Settlement will apply to all current and future shippers on Great Lakes' system. We do not expect the GL Settlement to have a material impact on the Partnership's earnings and cash flows in the context of the current market environment. See "Demand for Transportation Services and Contracting" related to Great Lakes within this section for further details.

Under the terms of the GL Settlement, reservation rates on Great Lakes' pipeline system were reduced by eight per cent, effective May 1, 2010. In addition, depreciation expense for Great Lakes' transmission plant decreased from 2.75 per cent to 1.48 per cent per year. Other depreciation rates for the plant either decreased or remained unchanged. Long-haul reservation rates from Great Lakes' western zone to its eastern zone declined by eight per cent from $0.338 per dekatherm to $0.311 per dekatherm and various short-haul firm paths experienced similar reductions. Rates for interruptible transportation service are derived on a 100 per cent load factor basis of firm transportation rates, effective June 1, 2010. All other terms of the settlement were effective May 1, 2010.

Great Lakes' obligation to share interruptible transportation revenues as established under the September 24, 1992 Stipulation and Agreement in Partial Settlement of Rate Proceedings in FERC Docket No. RP91-143 was eliminated under the GL Settlement, effective May 1, 2010. On July 1, 2010, Great Lakes paid out the interruptible transportation revenue sharing accumulated prior to May 1, 2010 and filed its final interruptible transportation revenue sharing report with the FERC in Docket No. RP91-143-061. Under the GL Settlement, Great Lakes has agreed to a new revenue sharing provision with respect to revenues, both firm and interruptible, it receives in excess of $500 million during the period between November 1, 2010 and October 31, 2012. Great Lakes will share with qualifying shippers 50 per cent of any qualifying revenues collected during this period in excess of the $500 million threshold.

The GL Settlement rates will remain in effect through at least November 30, 2011. The GL Settlement includes a moratorium on participants and customers filing any NGA Section 5 rate case to place new rates into effect prior to November 1, 2012. There is also a moratorium on Great Lakes filing a general NGA Section 4 rate case prior to June 1, 2011 to place new rates into effect prior to December 1, 2011. These moratoria are subject to conditions detailed in the GL Settlement. In addition, the GL Settlement requires Great Lakes to file a NGA Section 4 general rate case no later than November 1, 2013.

Air Emissions – The Clean Air Act (CAA) and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and also impose various monitoring and reporting requirements.

By letter dated December 28, 2009, the EPA required Great Lakes to provide information regarding its natural gas compressor stations in the states of Minnesota, Wisconsin and Michigan as part of the EPA's review of Great Lakes' compliance with the CAA. On May 28, 2010, Great Lakes submitted its final response to the EPA. To date, Great Lakes has not received further correspondence from the EPA with respect to this submission. Any issues that may arise as a result of this information request are not determinable at this time.

HOW WE EVALUATE OUR OPERATIONS

We evaluate our business primarily on the basis of the underlying operating results for each of our pipeline systems, along with a measure of Partnership cash flows. This measure does not have any standardized meaning prescribed by U.S. generally accepted accounting principles (GAAP). It is, therefore, considered to be a non-GAAP measure and is unlikely to be comparable to similar measures presented by other entities. Partnership cash flows include cash distributions from the Partnership's equity investments, Great Lakes and Northern Border, plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja (post-acquisition) and Tuscarora, net of Partnership costs and distributions declared to the general partner.

RESULTS OF OPERATIONS OF TC PIPELINES, LP

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 policies and estimates during the six months ended June 30, 2010.

Information about our critical accounting estimates is included under Item 7. "Management Discussion and Analysis of Financial Condition and Results of Operations," in our Annual Report on Form 10-K for the year ended December 31, 2009.

NET INCOME

The Partnership uses the non-GAAP financial measure "Net income prior to recast" as a financial performance measure. Net income prior to recast excludes North Baja's net income for periods prior to July 1, 2009, the date on which the Partnership acquired North Baja. The acquisition of North Baja from TransCanada was accounted for as a transaction under common control, similar to a pooling of interests, whereby the Partnership's historical financial information was recast to include the net income of North Baja for all periods presented, which included income that did not accrue to the Partnership's general partner interest or to the Partnership's common units, but rather accrued to North Baja's former parent.

Net income prior to recast is presented to enhance investors' understanding of the way management analyzes the Partnership's financial performance. Net income prior to recast is provided as a supplement to GAAP financial results and is not meant to be considered in isolation or as a substitute for financial results prepared in accordance with GAAP.

To supplement our financial statements, we have presented a comparison of the earnings contribution components from each of our investments. We have presented net income in this format to enhance investors' understanding of the way management analyzes our financial performance. We believe this summary provides a more meaningful comparison of our net income to prior years, as we account for our partially-owned pipeline systems using the equity method. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

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The shaded areas in the tables below disclose the results from Great Lakes and Northern Border, representing 100 per cent of each entity's operations for the given period.

(unaudited) (millions of dollars)	For the three months ended June 30, 2010					For the three months ended June 30, 2009				
	PipeLP	Other Pipes(a)	Corp(b)	GLGT	NBPC(c)	PipeLP	Other Pipes(a)	Corp(b)	GLGT	NBPC(c)
Transmission revenues	17.0	17.0	-	62.9	65.8	8.2	8.2	-	69.0	54.2
Operating expenses	(3.3)	(3.3)	-	(15.6)	(19.7)	(1.2)	(1.2)	-	(17.1)	(18.3)
General and administrative	(1.1)	-	(1.1)	-	-	(2.9)	-	(2.9)	-	-
	12.6	13.7	(1.1)	47.3	46.1	4.1	7.0	(2.9)	51.9	35.9
Depreciation	(3.7)	(3.7)	-	(10.1)	(15.4)	(1.7)	(1.7)	-	(14.6)	(15.5)
Financial charges, net and other	(6.5)	(1.0)	(5.5)	(7.7)	(6.0)	(7.0)	(1.2)	(5.8)	(8.1)	(9.2)
Michigan business tax	-	-	-	(1.2)	-	-	-	-	(1.3)	-
				28.3	24.7				27.9	11.2
Equity income	25.3	-	-	13.1	12.2	18.3	-	-	12.9	5.4
Net income prior to recast	27.7	9.0	(6.6)	13.1	12.2	13.7	4.1	(8.7)	12.9	5.4
North Baja's contribution prior to acquisition(d)	-	-	-	-	-	4.2	4.2	-	-	-
Net income(d)	27.7	9.0	(6.6)	13.1	12.2	17.9	8.3	(8.7)	12.9	5.4

(unaudited) (millions of dollars)	For the six months ended June 30, 2010					For the six months ended June 30, 2009				
	PipeLP	Other Pipes(a)	Corp(b)	GLGT	NBPC(c)	PipeLP	Other Pipes(a)	Corp(b)	GLGT	NBPC(c)
Transmission revenues	34.4	34.4	-	135.8	134.9	16.6	16.6	-	151.5	128.7
Operating expenses	(6.7)	(6.7)	-	(29.8)	(37.7)	(2.6)	(2.6)	-	(33.1)	(36.8)
General and administrative	(2.4)	-	(2.4)	-	-	(4.1)	-	(4.1)	-	-
	25.3	27.7	(2.4)	106.0	97.2	9.9	14.0	(4.1)	118.4	91.9
Depreciation	(7.4)	(7.4)	-	(24.4)	(30.8)	(3.5)	(3.5)	-	(29.2)	(30.8)
Financial charges, net and other	(12.7)	(2.0)	(10.7)	(15.6)	(12.0)	(14.3)	(2.3)	(12.0)	(16.3)	(18.3)
Michigan business tax	-	-	-	(2.7)	-	-	-	-	(3.1)	-

				63.3	54.4				69.8	42.8
Equity income	56.2	-	-	29.4	26.8	53.4	-	-	32.4	21.0
Net income prior to recast	61.4	18.3	(13.1)	29.4	26.8	45.5	8.2	(16.1)	32.4	21.0
North Baja's contribution prior to acquisition(d)	-	-	-	-	-	8.3	8.3	-	-	-
Net income(d)	61.4	18.3	(13.1)	29.4	26.8	53.8	16.5	(16.1)	32.4	21.0

(a) “Other Pipes” includes the results of North Baja and Tuscarora.

(b) “Corp” includes the costs of the Partnership, but excludes the costs of its subsidiaries.

(c) The Partnership owns a 50 per cent general partner interest in Northern Border. Equity income from Northern Border includes the 12-year amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the additional 20 per cent acquisition in April 2006.

(d) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada's carrying value and the Partnership’s historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

Second Quarter 2010 Compared with Second Quarter 2009
Net income increased $9.8 million to $27.7 million in the second quarter of 2010 compared to $17.9 million in the same period in 2009. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast increased $14.0 million to $27.7 million in the second quarter of 2010 compared to $13.7 million in the same period in 2009. This increase was primarily due to higher equity income from Northern Border, net income from North Baja and lower general and administrative charges at the Partnership level.

Equity income from Northern Border was $12.2 million in the second quarter of 2010, an increase of $6.8 million compared to the same period in 2009. The increase in equity income was primarily due to increased transmission revenues and reduced financial charges. Northern Border's transmission revenues increased $11.6 million primarily due to reduced deliveries of natural gas to Midwest markets from other supply sources which resulted in increased demand for transportation services on Northern Border in the second quarter of 2010. Financial charges, net and other decreased $3.2 million in the second quarter of 2010 compared to the same period in 2009 primarily due to lower effective interest rates and average debt outstanding.

Equity income from Great Lakes was $13.1 million in the second quarter of 2010, an increase of $0.2 million compared to $12.9 million for the same period in 2009. The increase in equity income was primarily due to depreciation rate reductions from the GL Settlement and lower operating expenses, offset by decreased transmission revenues. Great Lakes' transmission revenues for the three months ended June 30, 2010 decreased $6.1 million compared to the same period last year due to lower transportation values and decreased demand for short-term transportation and the impact of the GL Settlement rates on long-term revenues. Operating expenses decreased $1.5 million primarily due to lower maintenance costs, offset by prior year property tax adjustments. The second quarter impact of the GL Settlement, effective May 1, 2010, was a reduction in long-term revenues and depreciation of $1.5 million and $4.1 million, respectively. The reduction in Great Lakes' long-term revenues noted in the second quarter will be reflected in the Partnership cash flows in the third quarter of 2010.

Net income from Other Pipes, which includes results from North Baja and Tuscarora, was $9.0 million in the second quarter of 2010, an increase of $0.7 million compared to the same period in 2009. Excluding the contribution of $4.2 million from North Baja prior to the acquisition, net income from Other Pipes increased $4.9 million in the second quarter of 2010. This increase was primarily due to the $5.0 million contribution to net income from North Baja in the second quarter of 2010.

Costs at the Partnership level were $6.6 million in the second quarter of 2010, a decrease of $2.1 million compared to the same period in 2009. This decrease was primarily due to costs incurred in 2009 relating to the North Baja acquisition and Incentive Distribution Rights (IDR) restructuring.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009
Net income increased $7.6 million to $61.4 million for the six months ended June 30, 2010 compared to $53.8 million in the same period in 2009. Excluding the contribution from North Baja prior to the acquisition, net income prior to recast increased $15.9 million to $61.4 million for the six months ended June 30, 2010 compared to $45.5 million in the same period in 2009. This increase was primarily due to net income from North Baja, increased equity income from Northern Border, lower general and administrative costs and financial charges at the Partnership level, partially offset by lower equity income from Great Lakes.

Equity income from Northern Border was $26.8 million for the six months ended June 30, 2010, an increase of $5.8 million compared to the same period in 2009. The increase in equity income was primarily due to increased transmission revenues and reduced financial charges, net and other. Northern Border's transmission revenues increased $6.2 million for the six months ended June 30, 2010 due to an increase in demand for services on Northern Border during the first six months of 2010. Financial charges, net and other decreased $6.3 million for the six months ended June 30, 2010 compared to the same period in 2009 primarily due to lower effective interest rates and average debt outstanding.

Equity income from Great Lakes was $29.4 million for the six months ended June 30, 2010, a decrease of $3.0 million compared to $32.4 million for the same period in 2009. The decrease in equity income was primarily due to decreased transmission revenues, offset by depreciation rate reductions from the GL Settlement and lower operating expenses. Great Lakes' transmission revenues for the six months ended June 30, 2010 decreased $15.7 million compared to the same period in 2009 due to lower transportation values resulting in reduced sales of short-term capacity and lower throughput resulting in lower variable usage revenue and the impact of the GL Settlement rates on long-term revenues. Operating expenses decreased $3.3 million primarily due to lower maintenance costs. For the six months ended June 30, 2010, the impact of the GL Settlement, which was effective May 1, 2010, was a reduction in long-term revenues and depreciation of $1.5 million and $4.1 million, respectively.

Net income from Other Pipes, which includes results from North Baja and Tuscarora, was $18.3 million for the six months ended June 30, 2010, an increase of $1.8 million compared to the same period in 2009. Excluding the contribution of $8.3 million from North Baja prior to the acquisition, net income from Other Pipes increased $10.1 million for the six months ended June 30, 2010. This increase was primarily due to the $10.4 million contribution to net income from North Baja for the six months ended June 30, 2010.

Costs at the Partnership level were $13.1 million for the six months ended June 30, 2010, a decrease of $3.0 million compared to the same period in 2009. The decrease was primarily due to costs incurred in the second quarter of 2009 relating to the North Baja acquisition and IDR restructuring, along with lower financial charges in 2010 resulting from lower effective interest rates.

PARTNERSHIP CASH FLOWS

The Partnership uses the non-GAAP financial measures "Partnership cash flows" and "Partnership cash flows before general partner distributions" as they provide measures of cash generated during the period to evaluate our cash distribution capability. As well, management uses these measures as a basis for recommendations to our general partner's board of directors regarding the distribution to be declared each quarter. Partnership cash flow information is presented to enhance investors' understanding of the way that management analyzes the Partnership's financial performance.

Partnership cash flows include cash distributions from the Partnership's equity investments, Great Lakes and Northern Border, plus operating cash flows from the Partnership's wholly-owned subsidiaries, North Baja (post-acquisition) and Tuscarora, net of Partnership costs and distributions declared to the general partner.

Partnership cash flows and Partnership cash flows before general partner distributions 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.

Non-GAAP Measures
Reconciliations of Net Income to Net Income Prior to Recast and Partnership Cash Flows

(unaudited) (millions of dollars except per common unit amounts)	Three months ended June 30, 2010	2009	Six months ended June 30, 2010	2009
Net income(a)	27.7	17.9	61.4	53.8
North Baja's contribution prior to acquisition(a)	-	(4.2)	-	(8.3)
Net income prior to recast	27.7	13.7	61.4	45.5
Add:				
Cash distributions from Great Lakes(b)	18.0	21.7	33.7	34.2
Cash distributions from Northern Border(b)	21.5	22.5	37.9	46.7
Cash flows provided by North Baja's operating activities	9.2	-	13.9	-
Cash flows provided by Tuscarora's operating activities	4.8	4.8	12.0	12.0
	53.5	49.0	97.5	92.9
Less:				
Equity income from investment in Great Lakes	(13.1)	(12.9)	(29.4)	(32.4)
Equity income from investment in Northern Border	(12.2)	(5.4)	(26.8)	(21.0)
North Baja's net income	(5.0)	-	(10.4)	-
Tuscarora's net income	(4.0)	(4.1)	(7.9)	(8.2)
	(34.3)	(22.4)	(74.5)	(61.6)
Partnership cash flows before general partner distributions	46.9	40.3	84.4	76.8
General partner distributions(c)	(0.7)	(3.2)	(1.4)	(6.4)
Partnership cash flows	46.2	37.1	83.0	70.4
Cash distributions declared	(34.4)	(30.7)	(68.9)	(58.5)
Cash distributions declared per common unit(d)	$0.730	$0.730	$1.460	$1.435
Cash distributions paid	(34.4)	(27.8)	(68.9)	(55.5)
Cash distributions paid per common unit(d)	$0.730	$0.705	$1.460	$1.410

(a) The acquisition of North Baja from TransCanada was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of North Baja were recorded at TransCanada’s carrying value and the Partnership’s historical financial information was recast to include North Baja for all periods presented on a consolidated basis.

(b) In accordance with the cash distribution policies of the respective pipeline systems, cash distributions from Great Lakes and Northern Border are based on their respective prior quarter financial results.

(c) General partner distributions represent the cash distributions declared to the general partner with respect to its two per cent interest plus an amount equal to incentive distributions.

(d) Cash distributions declared per common unit and cash distributions paid per common unit are computed by dividing cash distributions, after the deduction of the general partner's allocation, by the number of common units outstanding. The general partner's allocation is computed based upon the general partner's two per cent interest plus an amount equal to incentive distributions.

Second Quarter 2010 Compared with Second Quarter 2009
Partnership cash flows increased $9.1 million to $46.2 million in the second quarter of 2010 compared to $37.1 million in the same period of 2009. This increase was primarily due to $9.2 million of cash flows provided by North Baja's operating activities in the second quarter of 2010, a decrease of $2.5 million in general partner distributions resulting from the restructuring of IDRs on July 1, 2009 and a decrease of $2.1 million in Partnership general and administrative costs in 2010 compared to 2009 resulting from costs incurred in the second quarter of 2009 relating to the North Baja acquisition and IDR restructuring. These positive factors were partially offset by decreased cash distributions from Great Lakes and Northern Border of $3.7 million and $1.0 million, respectively.

The Partnership paid distributions of $34.4 million in the second quarter of 2010, an increase of $6.6 million compared to the same period in 2009, due to an increase in the number of common units outstanding, an increase in the quarterly per common unit distribution amount and decreased general partner distributions resulting from the restructuring of the IDRs on July 1, 2009.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009
Partnership cash flows increased $12.6 million to $83.0 million for the six months ended June 30, 2010 compared to $70.4 million in the same period of 2009. This increase was primarily due to $13.9 million of cash flows provided by North Baja's operating activities in the six months ended June 30, 2010 and a decrease of $5.0 million in general partner distributions resulting from the restructuring of IDRs on July 1, 2009. Additionally, Partnership general and administrative costs were lower in the second quarter of 2010 due to costs incurred in the second quarter of 2009 relating to the North Baja acquisition and IDR restructuring, along with lower financial changes in 2010 resulting from lower effective interest rates. These positive factors were partially offset by decreased cash distributions from Northern Border of $8.8 million.

The Partnership paid distributions of $68.9 million in the six months ended June 30, 2010, an increase of $13.4 million compared to the same period in 2009, due to an increase in the number of common units outstanding, an increase in the quarterly per common unit distribution amount and decreased general partner distributions resulting from the restructuring of the IDRs on July 1, 2009.

Other Cash Flows
On March 5, 2010, we acquired the Yuma Lateral expansion facilities and contracts in place at that time for a purchase price of $7.6 million. The Yuma Lateral was placed into service on March 13, 2010.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES, LP

Overview

Our principal sources of liquidity include distributions received from our investments in Great Lakes and Northern Border, operating cash flows from North Baja and Tuscarora and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

Summary of the Partnership's Contractual Obligations

Yuma Lateral – The North Baja acquisition agreement provided that an additional payment of up to $2.4 million be made to TransCanada if any other shippers contracted for services on the Yuma Lateral before June 30, 2010. On June 29, 2010, a potential shipper signed a precedent agreement with North Baja to enter into agreements for service on the Yuma Lateral. An amendment to the acquisition agreement between the Partnership and TransCanada was entered into on June 29, 2010 to allow TransCanada to continue to pursue additional contracts until December 31, 2010 and, as a result, receive an additional payment of up to $2.4 million.

The Partnership's Debt and Credit Facility

The following table summarizes the Partnership's debt and credit facility outstanding as of June 30, 2010:

(unaudited) (millions of dollars)	Total	Payments Due by Period Less Than 1 Year	Long-term Portion
Senior Credit Facility due 2011	482.0	-	482.0
7.13% Series A Senior Notes due 2010	46.7	46.7	-
7.99% Series B Senior Notes due 2010	4.1	4.1	-
6.89% Series C Senior Notes due 2012	4.3	0.8	3.5
	537.1	51.6	485.5

The Partnership has a $475.0 million senior term loan and a $250.0 million senior revolving credit facility (together, Senior Credit Facility). There was $482.0 million outstanding under the Senior Credit Facility at June 30, 2010 (December 31, 2009 – $484.0 million). The interest rate on the Senior Credit Facility averaged 0.9 per cent for the three and six months ended June 30, 2010 (2009 – 1.7 per cent and 2.0 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 4.2 per cent for the three and six months ended June 30, 2010 (2009 – 4.8 per cent and 4.9 per cent). Prior to hedging activities, the interest rate was 1.1 per cent at June 30, 2010 (2009 – 1.2 per cent). At June 30, 2010, the Partnership was in compliance with all of its financial covenants, in addition to the other covenants which include restrictions on entering into mergers, consolidations and sales of assets, granting liens, material amendments to the Partnership Agreement, incurring additional debt and distributions to unitholders. As market conditions dictate, the Partnership intends to refinance this debt with either fixed-rate or variable-rate debt.

On April 22, 2010, the Partnership filed an automatic universal shelf registration statement on Form S-3 (ASR) with the SEC, which replaced the universal shelf registration filed in December 2008. The ASR will allow the Partnership to issue an indeterminate amount of securities of the Partnership, including both senior and subordinated debt securities and/or common units representing limited partnership interests in the Partnership. The ASR was effective immediately upon filing and will expire April 22, 2013.

Series A, B and C Senior Notes are secured by Tuscarora's transportation contracts, supporting agreements and substantially all of Tuscarora's property. The note purchase agreements contain certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners. On December 21, 2010, the Series A and B Senior Notes will mature. As market conditions dictate, the Partnership intends to refinance this debt with either fixed-rate or variable-rate debt.

Interest Rate Swaps and Options
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.

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at June 30, 2010 (December 31, 2009 – $375.0 million). Financial instruments are recorded at fair value on a recurring basis and are categorized into one of three categories based upon a fair value hierarchy. The Partnership has classified its derivative financial instruments as Level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. At June 30, 2010, the fair value of the interest rate swaps accounted for as hedges was negative $19.3 million (December 31, 2009 – negative $23.8 million), of which $13.4 million is classified as a current liability (December 31, 2009 – $12.9 million). The fair value of the interest rate swaps was calculated using the period-end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change. In the three and six months ended June 30, 2010, the Partnership recorded interest expense of $4.1 million and $8.3 million on the interest rate swaps and options (2009 – $3.7 million and $6.9 million).

Capital Requirements

2010

On June 30, 2010, the Partnership made an equity contribution of $2.3 million to Great Lakes, representing the Partnership's second and final installment of its 46.45 per cent share of a $10.0 million cash call issued by Great Lakes to expand backhaul capacity from St. Clair to Emerson. The first installment of $2.3 million was paid in the first quarter of 2010.

2011

Northern Border's distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by its Management Committee to establish the timing and amount of required equity contributions. In accordance with this policy, Northern Border currently estimates an equity contribution in 2011, of which the Partnership's share would be up to $60.0 million. The Partnership expects to finance this equity contribution with a combination of debt and operating cash flows.

To the extent the Partnership has any additional capital requirements with respect to our pipeline systems or makes acquisitions in the future, we expect to fund these requirements with operating cash flows, debt and/or equity.

2010 Second Quarter Cash Distribution

On July 20, 2010, the Partnership announced that the board of directors of the general partner declared the Partnership's second quarter 2010 cash distribution in the amount of $0.73 per common unit. The second quarter cash distribution, totaling $34.4 million, will be paid on August 13, 2010 to unitholders of record as of the close of business on July 31, 2010 in the following manner: $33.7 million to common unitholders (including $4.2 million to the general partner as holder of 5,797,106 common units and $8.2 million to TransCanada as holder of 11,287,725 common units) and $0.7 million to the general partner in respect of its two per cent general partner interest.

LIQUIDITY AND CAPITAL RESOURCES OF OUR PIPELINE SYSTEMS

Overview

Our pipeline systems' principal sources of liquidity are cash generated from operating activities, bank credit facilities and equity contributions from their partners. Our pipeline systems fund operating expenses, debt service and cash distributions to partners primarily with operating cash flow.

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

Our pipeline systems believe that their ability to obtain financing at reasonable rates, together with their history of consistent cash flow from operating activities, provide a solid foundation to meet their future liquidity and capital resource requirements. The Partnership's pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs that allow them to request credit support as circumstances dictate.

Summary of Great Lakes' Contractual Obligations

The following table summarizes Great Lakes' debt outstanding as of June 30, 2010:

(unaudited) (millions of dollars)	Total	Payments Due by Period Less than 1 year	Long-term Portion
8.74% series Senior Notes due 2010 to 2011	20.0	10.0	10.0
6.73% series Senior Notes due 2011 to 2018	72.0	9.0	63.0
9.09% series Senior Notes due 2012 to 2021	100.0	-	100.0
6.95% series Senior Notes due 2019 to 2028	110.0	-	110.0
8.08% series Senior Notes due 2021 to 2030	100.0	-	100.0
	402.0	19.0	383.0

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the Senior Note Agreements, approximately $216.0 million of Great Lakes' partners' capital was restricted as to distributions as of June 30, 2010 (December 31, 2009 – $221.0 million). Current maturities will be paid out of operating cash flows. As at June 30, 2010, Great Lakes was in compliance with all of its financial covenants.

Summary of Northern Border's Contractual Obligations

The following table summarizes Northern Border's debt outstanding as of June 30, 2010:

(unaudited) (millions of dollars)	Total	Payments Due by Period Less than 1 year	Long-term Portion
$250 million Credit Agreement due 2012	191.0	-	191.0
6.24% Senior Notes due 2016	100.0	-	100.0
7.50% Senior Notes due 2021	250.0	-	250.0
	541.0	-	541.0

As of June 30, 2010, Northern Border had outstanding borrowings of $191.0 million under its $250.0 million revolving credit agreement and was in compliance with the covenants of the agreement. The weighted average interest rate related to the borrowings on the credit agreement was 0.6 per cent at June 30, 2010.

CONTINGENCIES

Legal

As a result of extensive settlement negotiations, on July 15, 2010, the FERC approved, without modification, the GL Settlement. As approved, the GL Settlement will apply to all current and future shippers on Great Lakes' system.

Please read Part I, Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors that Impact the Business of Our Pipeline Systems – Government Regulation" in the Part for additional information with respect to the GL Settlement.

RELATED PARTY TRANSACTIONS

Please read Note 9 within Item 1. "Financial Statements" for information regarding related party transactions.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

We are exposed to market risk primarily from interest rate fluctuations. The Partnership and our pipeline systems are also exposed to other risks such as credit risk, liquidity risk, foreign exchange fluctuations and changes to natural gas prices, which we have determined to be less material to us and our pipeline systems. 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.

Market risk is the risk of loss arising from adverse changes in market rates. Our primary risk management objective is to protect earnings and cash flow, and ultimately, unitholder value. We do not use financial instruments for trading purposes.

Financial instruments on the balance sheet are recorded as assets and liabilities based on fair value. We estimate the fair value of financial instruments using available market information and appropriate valuation techniques. Changes in the fair value of financial instruments are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. Qualifying 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 AND INTEREST RATE RISK

From time to time, and in order to finance our business and that of our pipeline systems, the Partnership and our pipeline systems issue debt to invest in growth opportunities and provide for ongoing operations. The issuance of debt exposes the Partnership and our pipeline systems to market risk from changes in interest rates, which affect earnings and the value of the financial instruments we hold.

The Partnership and our pipeline systems use derivatives as part of our overall risk management policy to manage 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. The Partnership and our pipeline systems enter into interest rate swaps to mitigate the impact of changes in interest rates.
- Options – contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a financial instrument at a fixed price, either at a fixed date or at any time within a specified period. The Partnership and our pipeline systems enter into option agreements to mitigate the impact of changes in interest rates.

Interest rate risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in the market interest rates. Our interest rate exposure results from our Senior Credit Facility, which is subject to variability in London Interbank Offered Rate (LIBOR) interest rates. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk.

Our interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $375.0 million at June 30, 2010 (December 31, 2009 – $375.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap for the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap for the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid is 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility.

At June 30, 2010, the fair value of the interest rate swaps accounted for as hedges was negative $19.3 million (December 31, 2009 – negative $23.8 million), of which $13.4 million is classified as a current liability (December 31, 2009 – $12.9 million). The fair value of the interest rate swaps was calculated using the period-end interest rate; therefore, it is expected that this fair value will fluctuate over the year as interest rates change.

At June 30, 2010, we had $482.0 million (December 31, 2009 – $484.0 million) outstanding on our Senior Credit Facility. Utilizing the conditions of the interest rate swaps, if LIBOR interest rates hypothetically increased by one per cent (100 basis points) compared to the rates in effect at June 30, 2010, our annual interest expense would have increased and our net income would have decreased by $1.1 million; and if LIBOR interest rates hypothetically decreased to zero compared to the rates in effect at June 30, 2010, our annual interest expense would have decreased and our net income would have increased by $1.0 million. These amounts have been determined by considering the impact of the hypothetical interest rates on unhedged debt outstanding as of June 30, 2010.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its revolving credit facility. Northern Border regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. As of June 30, 2010, 70 per cent of Northern Border's outstanding debt was at fixed rates (December 31, 2009 – 62.0 per cent).

Standard & Poor's (S&P) issued a report on July 20, 2010 affirming Northern Border's issuer credit rating at "A-" but revised the outlook to "negative" from "stable." The negative outlook is based on declining credit metrics, which S&P believes are largely due to declining cash flows from Northern Border's firm transportation contracts. Notwithstanding this outlook, S&P has affirmed Northern Border's "A-" rating in light of its position as one of the largest shippers of natural gas exports from Canada, together with the credit strength of its investment-grade owners and contracted shippers. S&P will consider revising the outlook to "stable" if Northern Border is successful in recontracting capacity such that cash flows improve for a sustained period, or S&P may lower the rating if credit metrics remain weak, which would cause Northern Border's interest costs to increase.

If interest rates hypothetically increased by one per cent (100 basis points) compared with rates in effect at June 30, 2010, Northern Border's annual interest expense would increase and its net income would decrease by approximately $1.9 million; and if interest rates hypothetically decreased to zero per cent compared with rates in effect at June 30, 2010, Northern Border's annual interest expense would decrease and its net income would increase by approximately $0.6 million.

Great Lakes and Tuscarora utilize fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates. Interest rate risk does not apply to North Baja, as it currently does not have any debt.

OTHER RISKS

The Partnership is influenced by the same factors that influence our pipeline systems. None of our pipeline systems own any of the natural gas they transport; therefore, they do not assume any of the related natural gas commodity price risk with respect to transported natural gas volumes.

Counterparty credit risk 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 its contracts with the Partnership or its pipeline systems. 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. At June 30, 2010, the Partnership's maximum counterparty credit exposure consisted of accounts receivable of $6.0 million (December 31, 2009 – $7.4 million).

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 parties. Due to the deterioration of global financial markets in 2008 and 2009, we continue to closely monitor the creditworthiness of our counterparties, including financial institutions. Overall, we do not believe the Partnership and our pipeline systems have any significant concentrations of counterparty credit risk.

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, 2010, the Partnership has a committed revolving bank line of $250.0 million maturing in December 2011. As of June 30, 2010, the outstanding balance on this facility was $7.0 million. In addition, at June 30, 2010, Northern Border has a committed revolving bank line of $250.0 million maturing in April 2012. As of June 30, 2010, $191.0 million was drawn on this facility.

The Partnership does not have any material foreign exchange risks.

Item 4. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15(e) under the Exchange Act, the management of our General Partner, including the Principal Executive Officer and Principal Financial Officer, evaluated as of the end of the period covered by this report the effectiveness of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures may only provide reasonable assurance of achieving their control 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 our disclosure controls and procedures, as of the end of the period covered by this report, were effective to provide reasonable assurance that information required to be disclosed by us in reports that we file or submit under the Exchange Act is (a) recorded, processed, summarized and reported within the time periods specified by the rules and forms and (b) accumulated and communicated to 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, 2010, there has been 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

Item 1. Legal Proceedings

As a result of extensive settlement negotiations, on July 15, 2010, the FERC approved the GL settlement without modification. As approved, the GL Settlement will apply to all current and future shippers on Great Lakes' system.

Please read Part I, Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors that Impact the Business of Our Pipeline Systems – Government Regulation" for additional information with respect to the GL Settlement.

In the ordinary course of business, the Partnership and our pipeline systems are involved in various pending or potential legal actions. While management is unable to predict the ultimate outcome of these actions, it believes that any ultimate liability arising from these actions will not have a material adverse effect on our consolidated financial position, results of operations or cash flows; however, because of the inherent uncertainty of litigation, we cannot provide assurance that the resolution of any particular claim or proceeding to which the Partnership or our pipeline systems are a party will not have a material adverse effect on our financial position, results of operations or cash flows for the period in which the resolution occurs.

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, 2009 and Part II, Item 1A. "Risk Factors" in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2010.

Risks Inherent in Our Business

Our pipeline systems are subject to regulation by agencies, including the FERC, which could have an adverse impact on our ability to establish transportation rates that would allow recovery of the full cost of operating our pipeline systems, including a reasonable return, and our ability to make distributions.

Under the NGA, interstate transportation rates must be just, reasonable and not unduly discriminatory. Our pipeline systems are subject to extensive regulation by the FERC, the U.S. Department of Transportation, and other federal, state and local regulatory agencies. Regulatory actions taken by these agencies have the potential to adversely affect our pipeline systems' profitability. Federal regulation extends to such matters as:

- rates and charges;
- operating terms and conditions of service including creditworthiness requirements;
- types of services our pipeline systems may offer to their customers;
- construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- income tax allowance policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- standards of conduct business relations with certain affiliates; and
- integrity and safety of our pipeline systems and related operations.

Given the extent of regulation by the FERC and potential changes to regulations, we cannot predict:

- the federal regulations under which our pipeline systems will operate in the future;
- the effect that regulation will have on financial position, results of operations and cash flows of our pipeline systems and ourselves; or
- whether our cash flow will be adequate to make distributions to unitholders.

Tuscarora is currently operating under a rate settlement which precluded a party to the rate settlement from bringing any rate actions prior to May 31, 2010. Northern Border is required to file a new rate proceeding on or before December 31, 2012.

On July 15, 2010, the FERC approved, without modification, the GL Settlement. As a result, reservation rates on Great Lakes' pipeline system were reduced by eight per cent, effective May 1, 2010. Great Lakes is required to file a new rate proceeding under NGA Section 4 no later than November 1, 2013. Please read Part I, Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors that Impact the Business of Our Pipeline Systems – Government Regulation" for additional information with respect to the GL Settlement.

Action by the FERC on any currently pending regulatory matters as well as matters arising in the future could adversely affect our pipeline systems' abilities to establish or charge rates that would cover future increase in their costs, such as additional costs related to environmental matters including any climate change regulation, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot assure unitholders that our pipeline systems will be able to recover all of their costs through existing or future rates.

Should our pipeline systems fail to comply with all applicable FERC administered statutes, rules, regulations and orders, our pipeline systems could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

Finally, we cannot give any assurance regarding the future regulations under which our pipeline systems will operate their natural gas transportation businesses or the effect such regulations could ultimately have on our financial condition, results of operations and cash flows.

Our pipeline systems' operations are regulated by federal, state and local agencies responsible for environmental protection and operational safety, and costs of environmental compliance and the costs of environmental liabilities could exceed our estimates.

Risks of substantial costs and liabilities are inherent in pipeline operations and each of our pipeline systems may incur additional costs and liabilities in the future as a result of stricter environmental and safety laws, regulations, and enforcement policies and claims for personal or property damages resulting from our pipeline systems' operations. Moreover, new, stricter environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs or the cost of any remediation of environmental contamination that may become necessary, and these costs could be material. For instance, we may be required to obtain and maintain permits and approvals issued by various federal, state and local governmental authorities; limit or prevent releases of materials from our operations in accordance with these permits and approvals; and install pollution control equipment.

With respect to climate change-related policy, both the U.S. Congress and the EPA are considering widespread monitoring and permitting programs to address climate change. In December 2009, the EPA finalized two findings regarding six greenhouse gases (GHG) in response to the 2007 U.S. Supreme Court decision in Massachusetts v. EPA, which held that GHG could be determined to be "air pollutants" under the CAA and therefore, regulated under the CAA. On May 13, 2010, the EPA finalized a rule addressing implementation of certain CAA permitting programs for certain existing or future stationary sources of GHG emissions (Tailoring Rule), such as engines and turbines located at compressor stations. The Tailoring Rule establishes emissions thresholds and a phased timetable for permitting under the New Source Review Prevention of Significant Deterioration and Title V Operating Permit programs.

The EPA's Mandatory Reporting of Greenhouse Gases Rule, effective January 1, 2010, requires large sources and suppliers in the United States to report GHG emissions. The GHG emissions data will be used to inform the development of climate change policy. The EPA is finalizing the section of the rule pertaining to fugitive emissions, which is anticipated to be released by September 2010, and would be effective in 2011.

The ultimate impact to the Partnership related to reporting costs and compliance with the Tailoring Rule and the Mandatory Reporting of Greenhouse Gases Rule remains uncertain but may include increased time devoted to permitting, possible installation of new equipment at selected facilities and increased support staff. Some of our facilities may not be covered by the reporting rule or the Tailoring Rule because GHG emissions are expected to be below the triggering thresholds.

The U.S. Congress is also actively considering federal legislation to reduce domestic GHG emissions. Both the House of Representatives and Senate are considering a number of proposals to address climate change. At a regional level, several states have already promulgated measures to reduce emissions of GHGs.

At this time it is unknown what the future environmental compliance costs relating to GHG activities will be at federal and state levels but it is possible that compliance may negatively impact the operations of our pipeline systems, result in increased costs and reduce our income if our pipeline systems cannot recover any increased costs through their rates. The level of such impact will likely depend upon whether any of our pipeline systems' facilities will be directly responsible for compliance with any adopted program; whether cost containment measures will be available; the ability of our pipeline systems to recover compliance costs from their customers; and the manner in which allowances are provided.

Item 6. Exhibits

No.	Description
2.1	First Amendment to Agreement for Purchase And Sale of Membership Interest dated June 29, 2010 by and between Gas Transmission Northwest Corporation and TC PipeLines Intermediate Limited Partnership.
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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.

* Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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 29th day of July 2010.

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

By: /s/ Mark A.P. Zimmerman
Mark A.P. Zimmerman
President
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ Robert C. Jacobucci
Robert C. Jacobucci
Controller
TC PipeLines GP, Inc. (Principal Financial Officer)

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