TRANSCANADA PIPELINES LIMITED – SECOND QUARTER 2009

Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated July 30, 2009 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) for the three and six months ended June 30, 2009. It should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TCPL's 2008 Annual Report for the year ended December 31, 2008. Additional information relating to TCPL, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada PipeLines Limited. Unless otherwise indicated, "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries. Amounts are stated in Canadian dollars unless otherwise indicated. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TCPL's 2008 Annual Report.

Forward-Looking Information

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TCPL shareholders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects and financial performance of TCPL and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules, operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and the current economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause TCPL's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TCPL with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this quarterly report or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

TCPL uses the measures "comparable earnings", "earnings before interest, taxes, depreciation and amortization" (EBITDA), "comparable EBITDA", "earnings before interest and taxes" (EBIT), "comparable EBIT" and "funds generated from operations" in this MD&A. These measures do not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP). They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TCPL uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TCPL's operating performance, liquidity and ability to generate funds to finance operations.

Management uses the measures of comparable earnings, EBITDA and EBIT to better evaluate trends in the Company's underlying operations. Comparable earnings, comparable EBITDA and comparable EBIT comprise net income applicable to common shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant, but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating comparable earnings, comparable EBITDA and comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The table in the "Consolidated Results of Operations" section of this MD&A presents a reconciliation of comparable earnings, comparable EBITDA, comparable EBIT and EBIT to Net Income Applicable to Common Shares.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, and non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes, and non-controlling interests and preferred share dividends.

Funds generated from operations comprises net cash provided by operations before changes in operating working capital. A reconciliation of funds generated from operations to net cash provided by operations is presented in the "Liquidity and Capital Resources" section of this MD&A.

Financial Information Presentation

Effective January 1, 2009, TCPL revised the information presented in the tables of this MD&A to better reflect the operating and financing structure of the Company. The Pipelines and Energy results summaries are presented geographically by separating the Canadian and U.S. portions of each segment. The Company believes this new format more clearly describes the financial performance of its business units. The new format presents EBITDA and EBIT as the Company believes these measures provide increased transparency and more useful information with respect to the performance of the Company's individual assets. Segmented information has been retroactively reclassified to reflect these changes. These changes had no impact on reported consolidated Net Income Applicable to Common Shares.

Consolidated Results of Operations

Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income Applicable to Common Shares

For the three months ended June 30 *(unaudited)* *(millions of dollars)*	Pipelines 2009	Pipelines 2008	Energy 2009	Energy 2008	Corporate 2009	Corporate 2008	Total 2009	Total 2008
Comparable EBITDA[1]	**747**	714	**301**	260	**(31)**	(26)	**1,017**	948
Depreciation and amortization	**(258)**	(257)	**(87)**	(58)	**-**	-	**(345)**	(315)
Comparable EBIT[1]	**489**	457	**214**	202	**(31)**	(26)	**672**	633
Specific items:								
Fair value adjustment of natural gas inventory and forward contracts	**-**	-	**(7)**	12	**-**	-	**(7)**	12
EBIT[1]	**489**	457	**207**	214	**(31)**	(26)	**665**	645
Interest expense							**(264)**	(191)
Financial charges of joint ventures							**(16)**	(17)
Interest income and other							**34**	20
Income taxes							**(95)**	(122)
Non-controlling interests and preferred share dividends							**(13)**	(17)
Net Income Applicable to Common Shares							**311**	318
Specific items (net of tax):								
Fair value adjustment of natural gas inventory and forward contracts							**5**	(8)
Comparable Earnings[1]							**316**	310

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, and comparable earnings.

For the six months ended June 30 *(unaudited)* *(millions of dollars)*	Pipelines **2009**	Pipelines 2008	Energy **2009**	Energy 2008	Corporate **2009**	Corporate 2008	Total **2009**	Total 2008
Comparable EBITDA[1]	**1,618**	1,516	**591**	547	**(61)**	(48)	**2,148**	2,015
Depreciation and amortization	**(518)**	(511)	**(173)**	(114)	**-**	-	**(691)**	(625)
Comparable EBIT[1]	**1,100**	1,005	**418**	433	**(61)**	(48)	**1,457**	1,390
Specific items:								
Fair value adjustment of natural gas inventory and forward contracts	**-**	-	**(20)**	(5)	**-**	-	**(20)**	(5)
Calpine bankruptcy settlements	**-**	279	**-**	-	**-**	-	**-**	279
GTN lawsuit settlement	**-**	17	**-**	-	**-**	-	**-**	17
Writedown of Broadwater LNG project costs	**-**	-	**-**	(41)	**-**	-	**-**	(41)
EBIT[1]	**1,100**	1,301	**398**	387	**(61)**	(48)	**1,437**	1,640
Interest expense							**(565)**	(415)
Financial charges of joint ventures							**(30)**	(33)
Interest income and other							**56**	31
Income taxes							**(209)**	(372)
Non-controlling interests and preferred share dividends							**(48)**	(88)
Net Income Applicable to Common Shares							**641**	763
Specific items (net of tax):								
Fair value adjustment of natural gas inventory and forward contracts							**14**	4
Calpine bankruptcy settlements							**-**	(152)
GTN lawsuit settlement							**-**	(10)
Writedown of Broadwater LNG project costs							**-**	27
Comparable Earnings[1]							**655**	632

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT, EBIT, and comparable earnings.

TCPL's net income applicable to common shares in second quarter 2009 was $311 million compared to $318 million in second quarter 2008. The decrease in net income applicable to common shares reflects:

- increased EBIT from Pipelines, primarily due to the positive impact of a stronger U.S. dollar on Pipelines' U.S. operations;

- decreased EBIT from Energy primarily due to lower power prices in Western Power and a $13 million year-over-year change in the after tax fair value adjustment of natural gas inventory and forward contracts. These decreases were partially offset by increased earnings in Bruce Power due to higher realized prices and in Eastern Power from the start up of Portlands Energy and the Carleton wind farm, and in the Natural Gas Storage business due to a lower cost of proprietary natural gas sold;

- increased EBIT losses from Corporate due to higher support services costs as a result of a growing asset base; and

- increased interest expense due to debt issuances throughout 2008 and first quarter 2009 offset by decreased income tax expense primarily due to reduced earnings and positive income tax adjustments in 2009.

Comparable earnings in second quarter 2009 were $316 million compared to $310 million for the same period in 2008. Comparable earnings in second quarter 2009 and 2008 excluded $5 million of after tax unrealized losses ($7 million pre-tax) and $8 million of after tax unrealized gains ($12 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory and natural gas forward purchase and sale contracts.

Comparable EBIT was $672 million in second quarter 2009 compared to $633 million in second quarter 2008. The increase in comparable EBIT of $39 million was primarily due to increases in Pipelines and Energy, partially offset by increased support services costs in Corporate.

TCPL's net income applicable to common shares in the first six months of 2009 was $641 million compared to $763 million for the same period in 2008. The $122 million decrease in net income applicable to common shares reflects:

- decreased EBIT from Pipelines due to $152 million of after tax gains ($279 million pre-tax) on the sale of shares received by GTN and Portland for Calpine bankruptcy settlements and proceeds from a GTN lawsuit settlement of $10 million after tax ($17 million pre-tax) received in first quarter 2008. The impact of these items on the Pipelines segment was partially offset by the positive impact of a stronger U.S. dollar on Pipelines' U.S. operations.

- increased EBIT from Energy due to increased contribution from Bruce Power as a result of higher realized prices and output, Eastern Power from the start up of Portlands Energy and the Carleton wind farm, and the impact of a $27 million after tax ($41 million pre-tax) writedown of costs capitalized for the Broadwater liquefied natural gas (LNG) project in first quarter 2008. These positive impacts in Energy were partially offset by decreased contributions from Western Power due to lower overall realized prices and lower volumes of power sold.

- increased EBIT losses from Corporate due to higher support services costs as a result of a growing asset base; and

- increased interest expense due to debt issuances throughout 2008 and first quarter 2009, and the negative impact of a stronger U.S. dollar, partially offset by decreased income tax expense due to lower earnings and positive income tax adjustments in 2009.

Comparable earnings in the first six months of 2009 were $655 million compared to $632 million for the same period in 2008. Comparable earnings for the first six months of 2009 and 2008 excluded $14 million after tax ($20 million pre-tax) and $4 million after tax ($5 million pre-tax), respectively, of net unrealized losses resulting from changes in the fair value of proprietary natural gas inventory and natural gas forward purchase and sale contracts. In addition, comparable earnings in the first six months of 2008 excluded the $152 million after tax gain on Calpine bankruptcy settlements, the $10 million after tax gain on the GTN lawsuit settlement and the $27 million after tax writedown of Broadwater LNG project costs.

Comparable EBIT was $1.5 billion in the first six months of 2009 compared to $1.4 billion in 2008. The increase in comparable EBIT of $67 million was primarily due to an increase in Pipelines' comparable EBIT, partially offset by a decrease in Energy's comparable EBIT and increased support services costs in Corporate.

Results from each of the segments for the three and six month periods ended June 30, 2009 are discussed further in the Pipelines, Energy and Corporate sections of this MD&A.

Pipelines

The Pipelines business generated comparable EBIT of $489 million and $1.1 billion in the three and six month periods ended June 30, 2009, respectively, compared to $457 million and $1.0 billion for the same periods in 2008.

Comparable EBIT for first six months of 2008 excluded the $279 million of gains realized by GTN and Portland for the Calpine bankruptcy settlements and the $17 million of proceeds received by GTN from a lawsuit settlement with a software supplier.

Pipelines Results

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2009**	2008	**2009**	2008
Canadian Pipelines				
Canadian Mainline	**288**	283	**572**	573
Alberta System	**177**	179	**345**	358
Foothills	**34**	34	**68**	69
Other (TQM, Ventures LP)	**12**	13	**31**	26
Canadian Pipelines Comparable EBITDA(1)	**511**	509	**1,016**	1,026
U.S. Pipelines				
ANR	**73**	72	**206**	174
GTN	**49**	46	**110**	98
Great Lakes	**33**	29	**77**	65
Iroquois	**21**	12	**44**	27
PipeLines LP(2)	**16**	15	**40**	34
Portland(2)	**2**	2	**16**	14
International (Tamazunchale, TransGas, INNERGY/Gas Pacifico)	**15**	12	**28**	22
General, administrative and support costs(3)	**(3)**	(5)	**(6)**	(10)
Non-controlling interests(2)	**38**	39	**103**	93
U.S. Pipelines Comparable EBITDA(1)	**244**	222	**618**	517
Business Development Comparable EBITDA(1)	**(8)**	(17)	**(16)**	(27)
Pipelines Comparable EBITDA(1)	**747**	714	**1,618**	1,516
Depreciation and amortization	**(258)**	(257)	**(518)**	(511)
Pipelines Comparable EBIT(1)	**489**	457	**1,100**	1,005
Specific items:				
Calpine bankruptcy settlements(4)	**-**	-	**-**	279
GTN lawsuit settlement	**-**	-	**-**	17
Pipelines EBIT(1)	**489**	457	**1,100**	1,301

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.

(2) PipeLines LP and Portland results reflect TCPL's 32.1 per cent and 61.7 per cent ownership interests, respectively. The non-controlling interests reflect amounts not owned by TCPL.

(3) Represents costs associated with the Company's Canadian and foreign non-wholly owned pipelines.

(4) GTN and Portland received shares of Calpine with an initial value of $154 million and $103 million, respectively, from the bankruptcy settlements with Calpine. These shares were subsequently sold for an additional gain of $22 million.

Net Income for Wholly Owned Canadian Pipelines

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2009**	2008	**2009**	2008
Canadian Mainline	**67**	70	**133**	138
Alberta System	**40**	33	**79**	65
Foothills	**6**	6	**12**	13

Canadian Pipelines

Canadian Mainline's net income for the three and six months ended June 30, 2009 decreased $3 million and $5 million, respectively, primarily as a result of a lower average investment base and a lower rate of return on common equity (ROE) as determined by the National Energy Board (NEB), of 8.57 per cent in 2009 compared to 8.71 per cent in 2008, partially offset by higher operations, maintenance and administrative (OM&A) cost savings.

The Alberta System's net income was $40 million in second quarter 2009 and $79 million for the first six months of 2009 compared to $33 million and $65 million for the same periods in 2008. Earnings in 2009 reflect the impact of a higher average investment base compared to 2008 due to customer-driven expansion of this system, and the impact of a 2008-2009 settlement approved by the Alberta Utilities Commission (AUC) in December 2008.

The Alberta System's EBITDA was $177 million in second quarter 2009 and $345 million for the first six months of 2009 compared to $179 million and $358 million for the same periods in 2008. These decreases were primarily due to lower revenues as a result of lower depreciation approved in the settlement, partially offset by revenue received for higher financial charges and increased earnings from the settlement.

U.S. Pipelines

ANR's EBITDA in the three and six months ended June 30, 2009 was $73 million and $206 million, respectively, compared to $72 million and $174 million in the same periods in 2008. The increase in second quarter and the first six months in 2009 was primarily due to a stronger U.S. dollar in 2009, partially offset by reduced incidental natural gas and condensate sales primarily due to lower prices, and higher OM&A costs. For the six months ended June 30, 2009, the increase was also due to higher transportation and storage revenues as a result of increased utilization and favourable pricing on existing capacity and new growth projects.

GTN's EBITDA for the three and six months ended June 30, 2009 was $49 million and $110 million, respectively, an increase of $3 million and $12 million, respectively, from the same periods in 2008. The increases were primarily due to a stronger U.S. dollar in 2009, partially offset by lower revenues.

EBITDA for the remainder of the U.S. Pipelines was $122 million and $302 million for the three and six months ended June 30, 2009, respectively, compared to $104 million and $245 million for the same periods in 2008. The increase was primarily due to a stronger U.S. dollar, increased short-term revenues for Iroquois and lower support costs in 2009.

Operating Statistics

Six months ended June 30 (unaudited)	Canadian Mainline[(1)] 2009	Canadian Mainline[(1)] 2008	Alberta System[(2)] 2009	Alberta System[(2)] 2008	Foothills 2009	Foothills 2008	ANR[(3)] 2009	ANR[(3)] 2008	GTN System[(3)] 2009	GTN System[(3)] 2008
Average investment base ($ millions)	**6,566**	7,123	**4,671**	4,286	**717**	760	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**1,859**	1,762	**1,827**	1,930	**562**	660	**867**	861	**344**	394
Average per day	**10.3**	9.7	**10.1**	10.6	**3.1**	3.6	**4.8**	4.7	**1.9**	2.2

(1) Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the six months ended June 30, 2009 were 883 billion cubic feet (Bcf) (2008 – 971 Bcf); average per day was 4.9 Bcf (2008 – 5.3 Bcf).

(2) Field receipt volumes for the Alberta System for the six months ended June 30, 2009 were 1,848 Bcf (2008 – 1,919 Bcf); average per day was 10.2 Bcf (2008 – 10.5 Bcf).

(3) ANR's and the GTN System's results are not impacted by average investment base as these systems operate under fixed rate models approved by the U.S. Federal Energy Regulatory Commission.

Capitalized Project Costs

At June 30, 2009, Other Assets included $162 million of capitalized costs related to the Keystone pipeline system expansion to the U.S. Gulf Coast.

As at June 30, 2009, TCPL had advanced $142 million to the Aboriginal Pipeline Group (APG) with respect to the Mackenzie Gas Pipeline Project (MGP). TCPL and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. Project timing continues to be uncertain and discussions between the co-venture group and the Canadian government are ongoing. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TCPL, this may result in a reassessment of the carrying amount of the APG advances.

Energy

Energy's comparable EBIT was $214 million in second quarter 2009 compared to $202 million in second quarter 2008. Comparable EBIT excluded a net unrealized loss of $7 million and an unrealized gain of $12 million in second quarter 2009 and 2008, respectively, resulting from changes in the fair value of proprietary natural gas inventory and natural gas forward purchase and sale contracts.

Energy's comparable EBIT was $418 million for the first six months of 2009 compared to $433 million in same six months of 2008. Comparable EBIT excluded net unrealized losses of $20 million and $5 million in 2009 and 2008, respectively, resulting from changes in the fair value of proprietary natural gas inventory and natural gas forward purchase and sale contracts. In addition, comparable EBIT in 2008 excluded the $41 million writedown of costs previously capitalized for the Broadwater LNG project.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Canadian Power				
Western Power	**59**	138	**152**	237
Eastern Power	**60**	34	**112**	69
Bruce Power	**102**	49	**201**	103
General, administrative and support costs	**(11)**	(9)	**(19)**	(16)
Canadian Power Comparable EBITDA(1)	**210**	212	**446**	393
U.S. Power(2)				
Northeast Power	**76**	60	**118**	124
General, administrative and support costs	**(11)**	(10)	**(23)**	(19)
U.S. Power Comparable EBITDA(1)	**65**	50	**95**	105
Natural Gas Storage				
Alberta Storage	**36**	10	**75**	79
General, administrative and support costs	**(2)**	(4)	**(5)**	(6)
Natural Gas Storage Comparable EBITDA(1)	**34**	6	**70**	73
Business Development Comparable EBITDA(1)	**(8)**	(8)	**(20)**	(24)
Energy Comparable EBITDA(1)	**301**	260	**591**	547
Depreciation and amortization	**(87)**	(58)	**(173)**	(114)
Energy Comparable EBIT(1)	**214**	202	**418**	433
Specific items:				
Fair value adjustments of natural gas inventory and forward contracts	**(7)**	12	**(20)**	(5)
Writedown of Broadwater LNG project costs	**-**	-	**-**	(41)
Energy EBIT(1)	**207**	214	**398**	387

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.
(2) Includes Ravenswood effective August 2008.

Western and Eastern Canadian Power Comparable EBITDA(1)(2)

(unaudited) *(millions of dollars)*	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Revenues				
Western power	**174**	283	**389**	578
Eastern power	**71**	48	**140**	100
Other(3)	**41**	35	**90**	52
	286	366	**619**	730
Commodity Purchases Resold				
Western power	**(109)**	(110)	**(207)**	(266)
Eastern power	**-**	-	**-**	(2)
Other(4)	**(17)**	(21)	**(63)**	(34)
	(126)	(131)	**(270)**	(302)
Plant operating costs and other	**(43)**	(64)	**(87)**	(123)
General, administrative and support costs	**(11)**	(9)	**(19)**	(16)
Other income	**2**	1	**2**	1
Comparable EBITDA(2)	**108**	163	**245**	290

(1) Includes Portlands Energy and Carleton effective April 2009 and November 2008, respectively.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.
(3) Other revenue includes sales of natural gas and thermal carbon black.
(4) Other commodity purchases resold includes the cost of natural gas sold.

Western and Eastern Canadian Power Operating Statistics[(1)]

(unaudited)	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Sales Volumes (GWh)				
Supply				
Generation				
Western Power	**572**	506	**1,177**	1,135
Eastern Power	**421**	226	**776**	512
Purchased				
Sundance A & B and Sheerness PPAs	**2,725**	2,835	**5,165**	6,194
Other purchases	**122**	222	**307**	537
	3,840	3,789	**7,425**	8,378
Sales				
Contracted				
Western Power	**2,597**	2,819	**4,650**	5,893
Eastern Power	**419**	270	**810**	602
Spot				
Western Power	**824**	700	**1,965**	1,883
	3,840	3,789	**7,425**	8,378
Plant Availablity				
Western Power[(2)(3)]	**93%**	78%	**92%**	85%
Eastern Power	**98%**	96%	**98%**	97%

(1) Includes Portlands Energy and Carleton effective April 2009 and November 2008, respectively.
(2) Excludes facilities that provide power to TCPL under PPAs.
(3) Western Power plant availability increased in the three and six months ended June 30, 2009 due to outages at the MacKay River and Cancarb power facilities in 2008.

Western Power's EBITDA of $59 million in second quarter 2009 decreased $79 million compared to $138 million in second quarter 2008. The decrease was primarily due to lower earnings from the Alberta power portfolio resulting from lower overall realized power prices.

Western Power's EBITDA of $152 million in the first six months ended June 30, 2009 decreased $85 million compared to $237 million in the same period in 2008 primarily due to lower overall realized power prices on lower volumes of power sold, partially offset by lower power purchase arrangements (PPA) costs per megawatt hour (MWh).

Lower overall realized power prices resulted in decreases of $109 million and $189 million in Western Power's power revenues for the three and six months ended June 30, 2009, respectively, compared to the same periods in 2008.

Eastern Power's EBITDA of $60 million and $112 million for the three and six months ended June 30, 2009, respectively, increased $26 million and $43 million, respectively, compared to the same periods in 2008. These increases were primarily due to incremental earnings from Portlands Energy and the Carleton wind farm at Cartier Wind, which went into service in April 2009 and November 2008, respectively, as well as higher contracted revenue from Bécancour.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of $43 million and $87 million for the three and six months ended June 30, 2009, respectively, decreased from the same periods in 2008 primarily due to lower natural gas prices in Western Power.

Western Power manages the sale of its supply volumes on a portfolio basis. A portion of its supply is held for sale in the spot market for operational reasons and the amount of supply volumes eventually sold into the spot market is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management assists in minimizing costs in situations where Western Power would otherwise have to purchase electricity in the open market to fulfill its contractual sales obligations. Approximately 76 per cent of Western Power sales volumes were sold under contract in second quarter 2009, compared to 80 per cent in second quarter 2008. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2009, Western Power has entered into fixed-price power sales contracts to sell approximately 4,800 gigawatt hours (GWh) for the remainder of 2009 and 6,100 GWh for 2010.

Eastern Power is focused on selling power under long-term contracts. As a result, in second quarter 2009 and 2008, 100 per cent of Eastern Power sales volumes were sold under contract and are expected to continue to be fully sold under contract for the remainder of 2009 and 2010.

Bruce Power Results

(TCPL's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended June 30		Six months ended June 30	
	2009	2008	**2009**	2008
Revenues[1][2]	**240**	191	**461**	376
Operating Expenses[2]	**(138)**	(142)	**(260)**	(273)
Comparable EBITDA[3]	**102**	49	**201**	103
Bruce A Comparable EBITDA[3]	**47**	22	**88**	57
Bruce B Comparable EBITDA[3]	**55**	27	**113**	46
Comparable EBITDA[3]	**102**	49	**201**	103
Bruce Power – Other Information				
Plant availability				
Bruce A	**100%**	85%	**99%**	91%
Bruce B	**75%**	81%	**86%**	77%
Combined Bruce Power	**83%**	82%	**90%**	81%
Planned outage days				
Bruce A	**-**	26	**-**	33
Bruce B	**45**	50	**45**	100
Unplanned outage days				
Bruce A	**-**	1	**5**	2
Bruce B	**33**	15	**41**	48
Sales volumes (GWh)				
Bruce A	**1,563**	1,330	**3,058**	2,826
Bruce B	**1,662**	1,804	**3,801**	3,428
	3,225	3,134	**6,859**	6,254
Results per MWh				
Bruce A power revenues	**$64**	$63	**$64**	$61
Bruce B power revenues	**$70**	$56	**$63**	$56
Combined Bruce Power revenues	**$68**	$58	**$63**	$58
Combined Bruce Power operating expenses[4]	**$42**	$44	**$36**	$36
Percentage of Bruce B output sold to spot market	**40%**	33%	**38%**	39%

(1) Revenues include Bruce A's fuel cost recoveries of $11 million and $21 million for the three and six months ended June 30, 2009, respectively (2008 - $7 million and $13 million). Revenues also include gains of nil and $2 million as a result of changes in fair value of held-for-trading derivatives for the three and six months ended June 30, 2009, respectively (2008 - losses of $3 million and $6 million).

(2) Includes adjustments to eliminate the effects of inter-partnership transactions between Bruce A and Bruce B.

(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.

(4) Net of fuel cost recoveries and excluding depreciation.

TCPL's proportionate share of Bruce Power's comparable EBITDA increased $53 million to $102 million in second quarter 2009 compared to second quarter 2008 primarily due to higher realized prices as well as increased output and lower operating costs as a result of fewer outage days.

TCPL's proportionate share of Bruce A's comparable EBITDA increased $25 million to $47 million in second quarter 2009 compared to second quarter 2008 as a result of increased volumes and lower operating costs due to a decrease in outage days following the rescheduling of two planned outages from March 2009 to September 2009. Bruce A's availability in second quarter 2009 was 100 per cent as a result of having no outage days compared to an availability of 85 per cent and 27 outage days in the same period in 2008.

TCPL's proportionate share of Bruce B's comparable EBITDA increased $28 million to $55 million in second quarter 2009 compared to second quarter 2008 primarily due to higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism in Bruce B's contract with the Ontario Power Authority (OPA). This was partially offset by lower output due to a 13 day increase in total outage days compared to second quarter 2008.

In 2008, Bruce B did not recognize into revenue any of the support payments received under the floor price mechanism as the annual average spot price exceeded the average floor price. Amounts received under the floor price mechanism in any year are subject to repayment, if spot prices in the remainder of that year increase above the floor price. With respect to 2009, TCPL currently expects spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenue in the first six months of 2009 are expected to be repaid.

TCPL's proportionate share of Bruce Power's Comparable EBITDA increased $98 million to $201 million in the six months ended June 30, 2009 compared to the same period in 2008 as a result of higher realized prices as well as higher output and lower operating costs due to fewer outage days.

TCPL's share of Bruce Power's generation in second quarter 2009 increased to 3,225 GWh compared to 3,134 GWh in second quarter 2008. The Bruce Power units ran at a combined average availability of 83 per cent in second quarter 2009, compared to 82 per cent in second quarter 2008. In mid-April 2009, an approximate eight week planned outage of Bruce B Unit 8 commenced. An approximate six week maintenance outage of Bruce A Unit 4 and an approximate one month outage of Bruce A Unit 3 were rescheduled from March 2009 to September 2009. The overall plant availability percentage in 2009 is currently expected to be in the low 90s for the four Bruce B units and the mid 80s for the two operating Bruce A units.

Pursuant to the terms of a contract with the OPA, all of the output from Bruce A in second quarter 2009 was sold at a fixed price of $64.45 per MWh (before recovery of fuel costs from the OPA) compared to $63.00 per MWh in second quarter 2008. All output from the Bruce B Units 5 to 8 were subject to a floor price of $48.76 per MWh in second quarter 2009 and $47.66 per MWh in second quarter 2008. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

At June 30, 2009, Bruce B had sold forward approximately 1,900 GWh and 2,700 GWh, representing TCPL's proportionate share, for the remainder of 2009 and the year 2010, respectively. To reduce its exposure to spot prices, Bruce B had entered into most of these fixed price contracts in 2006 to 2008 when the spot price exceeded the floor price. Under these 'contracts for differences', Bruce B receives the difference between the contract price and spot price on output sold forward under contract. As a result, Bruce B's realized price of $70 per MWh and $63 per MWh in the three and six months ended June 30, 2009, respectively, reflects revenues recognized from both the floor price mechanism and contract sales, compared to $56 per MWh in the same periods in 2008 in which no revenues were recognized under the floor price mechanism.

As at June 30, 2009, Bruce A had incurred $2.9 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.2 billion for the refurbishment of Units 3 and 4.

U.S. Power Comparable EBITDA[1][2]

(unaudited) *(millions of dollars)*	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Revenues				
Power	**321**	215	**661**	441
Other[3][4]	**78**	95	**250**	177
	399	310	**911**	618
Commodity Purchases Resold				
Power	**(117)**	(105)	**(272)**	(239)
Other[5]	**(56)**	(96)	**(187)**	(162)
	(173)	(201)	**(459)**	(401)
Plant operating costs and other[4]	**(150)**	(49)	**(334)**	(93)
General, administrative and support costs	**(11)**	(10)	**(23)**	(19)
Comparable EBITDA[2]	**65**	50	**95**	105

(1) Includes Ravenswood effective August 2008.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA.
(3) Other revenue includes sales of natural gas.
(4) Includes activity at Ravenswood related to a third-party owned steam production facility operated by TCPL on behalf of the plant owner.
(5) Other commodity purchases resold includes the cost of natural gas sold.

U.S. Power Sales Operating Statistics[1]

(unaudited)	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Sales Volumes (GWh)				
Supply				
Generation	**1,404**	830	**2,572**	1,630
Purchased	**1,135**	1,339	**2,394**	2,817
	2,539	2,169	**4,966**	4,447
Sales				
Contracted	**1,791**	2,101	**3,577**	4,281
Spot	**748**	68	**1,389**	166
	2,539	2,169	**4,966**	4,447
Plant Availability	**78%**	96%	**68%**	94%

(1) Includes Ravenswood effective August 2008.

U.S. Power's EBITDA for the three months ended June 30, 2009 was $65 million, an increase of $15 million from the same period in 2008. Second quarter 2009 results reflect EBITDA from the Ravenswood facility acquired in August 2008 and the positive impact of the stronger U.S. dollar in 2009, partially offset by lower realized power prices in the New England market. For the six months ended June 30, 2009, U.S. Power's EBITDA of $95 million decreased $10 million from the same period in 2008, primarily due to decreased water flows from the TC Hydro generation assets in second quarter 2009 compared to the considerably higher than average levels experienced in 2008, and lower realized prices in the New England market, partially offset by a stronger U.S. dollar.

U.S. Power's power revenues for the three and six months ended June 30, 2009 of $321 million and $661 million, respectively, increased from $215 million and $441 million for the same periods in 2008 due to incremental revenue from the August 2008 acquisition of Ravenswood and the positive impact of the stronger U.S. dollar.

Power Commodity Purchases Resold of $117 million and $272 million for the three and six months ended June 30, 2009, respectively, increased from $105 million and $239 million compared to the same periods in 2008 primarily due to the impact of the stronger U.S. dollar in 2009.

Other Revenues and Other Commodity Purchases Resold of $78 million and $56 million, respectively, decreased in second quarter 2009 compared to second quarter 2008 as a result of decreased natural gas prices, partially offset by an increase in the volume of natural gas sold and purchased, and a stronger U.S. dollar. The decrease in Other Revenues was also partially offset by incremental revenues earned related to a steam generating facility at Ravenswood.

Other Revenue and Other Commodity Purchases Resold of $250 million and $187 million, respectively, increased $73 million and $25 million, respectively, in the first six months ended June 30, 2009 primarily due to higher volumes of natural gas sold and purchased, and the impact of a stronger U.S. dollar, partially offset by a decrease in natural gas prices. In addition, Other Revenues also increased as a result of incremental revenues earned related to the steam generating facility at Ravenswood.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of $150 million and $334 million for the three and six months ended June 30, 2009, respectively, increased from $49 million and $93 million compared to the same periods in 2008 due to the incremental costs from Ravenswood.

In the three and six months ended June 30, 2009, 29 per cent and 28 per cent, respectively, of power sales volumes were sold into the spot market, compared to three and four per cent for the same periods in 2008, as there were no power sales contracts in place for Ravenswood extending beyond 2008 at the time the facility was acquired. U.S. Power is focused on selling the majority of its power under contract to wholesale, commercial and industrial customers, while managing a portfolio of power supplies sourced from its own generation and wholesale power purchases. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2009, U.S. Power had entered into fixed-price power sales contracts to sell approximately 3,800 GWh for the remainder of 2009 and 8,100 GWh for 2010, although certain contracted volumes are dependent on customer usage levels. Actual amounts contracted in future periods will depend on market liquidity and other factors.

Natural Gas Storage

Natural Gas Storage's comparable EBITDA for the three and six month periods ended June 30, 2009 was $34 million and $70 million, respectively, compared to $6 million and $73 million for the same periods in 2008. The $28 million increase in EBITDA in second quarter 2009 was primarily due to a lower cost of proprietary natural gas sold at the Edson facility as well as increased third party storage revenues. The $3 million decrease in EBITDA for the six months ended June 30, 2009 was due to lower withdrawal activity and reduced sales of proprietary natural gas at the Edson facility compared to the same period in 2008.

Comparable EBITDA excluded net unrealized losses of $7 million and $20 million in the three and six months ended June 30, 2009, respectively (2008 - $12 million gain and $5 million loss), resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. TCPL manages its proprietary natural gas storage earnings by simultaneously entering into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments are recorded in each period on proprietary natural gas held in storage and these forward contracts are not representative of the amounts that will be realized on settlement. Beginning in second quarter 2009, the fair value of proprietary natural gas inventory held in storage is measured using a weighted average of forward prices for the following four months less selling costs. Previously the inventory was measured using the one-month forward price. The impact of this change on EBITDA for the three and six months ended June 30, 2009 was insignificant.

Depreciation and Amortization

Depreciation and Amortization for the three and six months ended June 30, 2009 of $87 million and $173 million, respectively, increased $29 million and $59 million, respectively, compared with the same periods in 2008, primarily due to the acquisition of Ravenswood in August 2008.

Corporate

Corporate EBIT losses for the three and six months ended June 30, 2009 were $31 million and $61 million, respectively, compared to losses of $26 million and $48 million for the same periods in 2008. These decreases in Corporate EBIT were primarily due to higher support services costs in 2009, reflecting a growing asset base.

Other Income Statement Items

Interest Expense

(unaudited)	Three months ended June 30		Six months ended June 30	
(million of dollars)	**2009**	2008	**2009**	2008
Interest on long-term debt[1]	**330**	234	**665**	482
Other interest and amortization	**(3)**	(11)	**17**	(8)
Capitalized interest	**(63)**	(32)	**(117)**	(59)
	264	191	**565**	415

(1) Includes interest for Junior Subordinated Notes.

Interest Expense for second quarter 2009 increased $73 million to $264 million from $191 million in second quarter 2008. Interest Expense for the six months ended June 30, 2009, increased $150 million to $565 million from $415 million for the six months ended June 30, 2008. The increases were primarily due to new debt issues of US$1.5 billion and $500 million in August 2008, US$2.0 billion in January 2009 and $700 million in February 2009. In addition, U.S. dollar-denominated interest expense increased due to the impact of a stronger U.S. dollar. These increases were partially offset by increased capitalization of interest to finance the Company's larger capital spending program in 2009.

On a consolidated basis, the positive impact of a stronger U.S. dollar on U.S. Pipelines and Energy EBIT is almost fully offset by the net negative impact on U.S. dollar interest expense and other income statement items, thereby effectively reducing the Company's net exposure to changes in foreign exchange.

Interest Income and Other was $34 million and $56 million for the three and six month periods ended June 30, 2009, respectively, compared to $20 million and $31 million for the same periods in 2008. The increase of $14 million and $25 million for the three and six months ended June 30, 2009, respectively, was primarily due to higher gains from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations and the positive impact of a stronger U.S. dollar. Partially offsetting these increases was reduced interest income as a result of lower interest rates in 2009.

Income Taxes were $95 million in second quarter 2009, compared to $122 million for the same period in 2008. Income Taxes for the six months ended June 30, 2009 were $209 million compared to $372 million for the same period in 2008. The decreases were primarily due to reduced earnings, higher income tax rate differentials and other positive income tax adjustments in 2009.

Non-Controlling Interests were $8 million for second quarter 2009 compared to $12 million for the same period in 2008. The decrease of $4 million was primarily due to lower earnings from PipeLines LP. Non-Controlling Interests of $37 million for the first six months of 2009, decreased $40 million compared to $77 million for the same period in 2008, primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy settlement in first quarter 2008.

Liquidity and Capital Resources

Global Market Conditions

Despite continued uncertainty in global financial markets, TCPL's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, as well as provide for planned growth. TCPL's liquidity position remains solid, underpinned by highly predictable cash flow from operations, significant cash balances on hand from recent debt and equity issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion and US$300 million, maturing in November 2010, December 2012 and February 2013, respectively. To date, no draws have been made on these facilities as TCPL has maintained continuous access to the Canadian commercial paper market on competitive terms. An additional approximate $230 million of capacity remains available on Canadian and U.S. dollar committed bank facilities at TCPL-operated affiliates with maturity dates from 2010 through 2012.

At June 30, 2009, the Company held cash and cash equivalents of $2.8 billion compared to $1.3 billion at December 31, 2008. The increase in cash and cash equivalents was primarily due to proceeds from the issuance of common shares in second quarter 2009 and long-term debt in first quarter 2009.

Operating Activities

Funds Generated from Operations(1)

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2009**	2008	**2009**	2008
Cash Flows				
Funds generated from operations(1)	**686**	668	**1,446**	1,585
Decrease/(increase) in operating working capital	**305**	(126)	**396**	(104)
Net cash provided by operations	**991**	542	**1,842**	1,481

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of funds generated from operations.

Net Cash Provided by Operations increased $449 million and $361 million for the three and six months ended June 30, 2009 compared to the same periods in 2008, primarily due to decreases in operating working capital. Funds Generated from Operations for the three and six months ended June 30, 2009, were $686 million and $1.4 billion, respectively, compared to $668 million and $1.6 billion for the same periods in 2008. The decrease for the six months ended June 30, 2009 was primarily due to $152 million of after tax proceeds received in 2008 from the Calpine bankruptcy settlement.

Investing Activities

Acquisitions, net of cash acquired, were $115 million in second quarter 2009 (2008 - $2 million) and $249 million (2008 - $4 million) for the six months ended June 30, 2009. The acquisitions included the increase in ownership interest in Keystone pursuant to an agreement with ConocoPhillips that closed in December 2008.

TCPL remains committed to executing its previously announced $21 billion capital expenditure program over the next four years. For the three and six months ended June 30, 2009, capital expenditures totalled $1.3 billion and $2.4 billion, respectively (2008 - $633 million and $1.1 billion), primarily related to the Keystone pipeline system, expansion of the Alberta System, refurbishment and restart of Bruce A Units 1 and 2, and construction of Kibby Wind, Halton Hills, Coolidge and Bison.

Financing Activities

The Company believes it is well positioned to fund its existing capital program through its growing internally-generated cash flow, the issuance of long-term debt and further subordinated capital, as required, in the form of preferred shares or other hybrid securities. As demonstrated by the recent sale of North Baja, TCPL will also continue to examine opportunities for portfolio management, including a greater role for PipeLines LP, in the financing of its capital program.

In the three and six months ended June 30, 2009, TCPL issued nil and $3.1 billion, respectively, (2008 - nil and $112 million), and retired $18 million and $500 million, respectively (2008 - $379 million and $773 million), of long-term debt. TCPL's notes payable increased $233 million and decreased $684 million in the three and six months ended June 30, 2009, respectively, compared to increases of $754 million and $1,090 million for the same periods in 2008.

On April 23, 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes shelf prospectus, which expired in April 2009. No amounts have been issued under this shelf prospectus.

In February 2009, TCPL issued Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued under the $1.5 billion debt shelf prospectus filed in March 2007.

In January 2009, TCPL issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued under a US$3.0 billion debt shelf prospectus filed in January 2009, which now has capacity of US$1.0 billion remaining.

Dividends

On July 30, 2009, TCPL's Board of Directors declared a dividend for the quarter ending September 30, 2009 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada Corporation's issued and outstanding common shares at the close of business on September 30, 2009. The Board also declared regular dividends on TCPL's preferred shares.

Significant Accounting Policies and Critical Accounting Estimates

To prepare financial statements that conform with Canadian GAAP, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The

Company uses the most current information available and exercises careful judgement in making these estimates and assumptions.

TCPL's significant accounting policies and critical accounting estimates have remained unchanged since December 31, 2008. For further information on the Company's accounting policies and estimates refer to the MD&A in TCPL's 2008 Annual Report.

Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TCPL's 2008 Annual Report except as follows:

2009 Accounting Changes

Rate-Regulated Operations
Effective January 1, 2009, the temporary exemption was withdrawn from the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1100 "Generally Accepted Accounting Principles", which permitted the recognition and measurement of assets and liabilities arising from rate regulation. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company chose to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". As a result, TCPL retained its current method of accounting for its rate-regulated operations, except that TCPL is required to recognize future income tax assets and liabilities, instead of using the taxes payable method, and records an offsetting adjustment to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1.4 billion were recorded January 1, 2009 in each of Future Income Taxes and Other Assets, respectively.

Adjustments to the 2009 financial statements have been made in accordance with the transitional provisions for Section 3465, which required a cumulative adjustment in the current period to future income taxes and a regulatory asset. Restatement of prior periods' financial statements was not permitted under Section 3465.

Intangible Assets
Effective January 1, 2009, the Company adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". Section 3064 gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. In addition, Section 3450 "Research and Development Costs" was withdrawn from the Handbook. Adopting this accounting change did not have a material effect on the Company's financial statements.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities
Effective January 1, 2009, the Company adopted the accounting provisions of Emerging Issues Committee (EIC) Abstract EIC 173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". Under EIC 173 an entity's own credit risk and the credit risk of its counterparties is taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adopting this accounting change did not have a material effect on the Company's financial statements.

Future Accounting Changes

International Financial Reporting Standards
The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Company will prepare its financial statements under IFRS commencing January 1, 2011.

TCPL has developed a conversion plan that is overseen by its IFRS Implementation and Steering Committees. The plan includes identifying resources and training requirements, analyzing the impact of key differences between Canadian GAAP and IFRS, and developing a phased approach to conversion implementation. The Company's conversion project is discussed in further detail in its 2008 Annual Report. TCPL continues to progress its conversion project by scheduling training sessions and IFRS updates for employees, reviewing new IFRS developments and assessing the impact that significant differences between Canadian GAAP and IFRS may have on TCPL.

Under existing Canadian GAAP, TCPL follows specific accounting policies unique to a rate-regulated business. TCPL is actively monitoring developments regarding potential future guidance on the applicability of certain aspects of rate-regulated accounting under IFRS. Developments in this area could have a significant effect on the scope of the Company's IFRS project and on TCPL's financial results under IFRS. On July 23, 2009, the IASB issued an exposure draft "Rate-regulated Activities" and the Company is assessing the impact of this exposure draft on TCPL.

The impact of the adoption of IFRS on the Company's consolidated financial statements and accounting systems is currently being evaluated. At the current stage of its IFRS project, TCPL cannot reasonably determine the full impact that adopting IFRS would have on its financial position and future results.

Financial Instruments Disclosure
The CICA implemented revisions to Handbook Section 3862 "Financial Instruments – Disclosures" for fiscal years ending after September 30, 2009. These revisions are intended to align the disclosure requirements for financial instruments to the maximum extent possible with the disclosure required under IFRS. These revisions require additional disclosure based on a three level hierarchy that reflects the significance of inputs used in measuring fair value. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of assets and liabilities included in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Fair values of assets and liabilities included in Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These changes will be applied by TCPL effective December 31, 2009.

Contractual Obligations

On June 16, 2009, the Company entered into an agreement to acquire ConocoPhillips' remaining interest in Keystone for approximately US$550 million plus the assumption of approximately US$200 million of short-term indebtedness. The transaction is expected to close in third quarter 2009. In addition, TCPL will also assume responsibility for ConocoPhillips' share of the capital investment required to complete the project, which is expected to result in an incremental commitment of US$1.7 billion through the end of 2012.

Other than the commitments discussed above and obligations for future debt and interest payments relating to debt issuances and redemptions discussed in the "Financing Activities" section of this

MD&A, there have been no other material changes to TCPL's contractual obligations from December 31, 2008 to June 30, 2009, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TCPL's 2008 Annual Report.

Financial Instruments and Risk Management

TCPL continues to manage and monitor its exposure to market, counterparty credit and liquidity risk.

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted 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 assets. Letters of credit and cash are the primary types of security provided to support these amounts. The Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At June 30, 2009, there were no significant amounts past due or impaired.

As the uncertainty in the global financial markets persists, TCPL continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TCPL must balance its market and counterparty credit risks when making business decisions.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions. Further discussion of the Company's ability to manage its cash and credit facilities is provided in the "Liquidity and Capital Resources" section in this MD&A.

Natural Gas Inventory

At June 30, 2009, the fair value of proprietary natural gas inventory held in storage as measured using a weighted average of forward prices for the following four months less selling costs was $44 million (December 31, 2008 - $76 million). Prior to second quarter 2009, inventory was measured using the one-month forward price. The impact of this change was insignificant.

The change in fair value of proprietary natural gas inventory in the three and six months ended June 30, 2009 resulted in pre-tax net unrealized losses of $6 million and $29 million, respectively, which were recorded as a decrease to Revenues and Inventories (gains of $42 million and $102 million for the three and six months ended June 30, 2008). The net change in fair value of natural gas forward purchase and sales contracts in the three and six months ended June 30, 2009 resulted in a pre-tax net unrealized loss of $1 million and a pre-tax net unrealized gain of $9 million (losses of $30 million and $107 million for the three and six months ended June 30, 2008), respectively, which were included in Revenues.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange forward contracts and options. At June 30, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $8.8 billion (US$7.6 billion) and a fair value of $9.2 billion (US$7.9 billion). At June

30, 2009, Deferred Amounts included $124 million for the fair value of derivatives used to hedge the Company's net U.S. dollar investment in foreign operations.

Information for the derivatives used to hedge the Company's net investment in its self-sustaining foreign operations is as follows:

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**June 30, 2009** **Fair Value**[1]	**June 30, 2009** **Notional or Principal Amount**	December 31, 2008 Fair Value[1]	December 31, 2008 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)[2]	**(116)**	**U.S. 1,450**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2009)[2]	**(3)**	**U.S. 100**	(42)	U.S. 2,152
U.S. dollar options (maturing 2009)[2]	**(5)**	**U.S. 300**	6	U.S. 300
	(124)	**U.S. 1,850**	(254)	U.S. 4,102

(1) Fair values equal carrying values.
(2) As at June 30, 2009.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

(unaudited) *(millions of dollars)*	**June 30, 2009** **Carrying Amount**	**June 30, 2009** **Fair Value**	December 31, 2008 **Carrying Amount**	December 31, 2008 **Fair Value**
Financial Assets[1]				
Cash and cash equivalents	**2,752**	**2,752**	1,300	1,300
Accounts receivable and other assets[2][3]	**1,036**	**1,036**	1,404	1,404
Due from TransCanada Corporation	**1,858**	**1,858**	1,529	1,529
Available-for-sale assets[2]	**23**	**23**	27	27
	5,669	**5,669**	4,260	4,260
Financial Liabilities[1][3]				
Notes payable	**1,041**	**1,041**	1,702	1,702
Accounts payable and deferred amounts[4]	**1,587**	**1,587**	1,364	1,364
Due to TransCanada Corporation	**3,207**	**3,207**	1,821	1,821
Accrued interest	**418**	**418**	361	361
Long-term debt and junior subordinated notes	**19,266**	**21,174**	17,367	16,152
Long-term debt of joint ventures	**1,099**	**1,122**	1,076	1,052
	26,618	**28,549**	23,691	22,452

(1) Consolidated Net Income Applicable to Common Shares in 2009 and 2008 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.
(2) At June 30, 2009, the Consolidated Balance Sheet included financial assets of $889 million (December 31, 2008 – $1,257 million) in Accounts Receivable and $170 million (December 31, 2008 - $174 million) in Other Assets.
(3) Recorded at amortized cost.
(4) At June 30, 2009, the Consolidated Balance Sheet included financial liabilities of $1,569 million (December 31, 2008 – $1,342 million) in Accounts Payable and $18 million (December 31, 2008 - $22 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

June 30, 2009 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]					
Fair Values[2]					
Assets	**$155**	**$174**	**$6**	**$16**	**$38**
Liabilities	**$(90)**	**$(206)**	**$(4)**	**$(50)**	**$(77)**
Notional Values					
Volumes[3]					
Purchases	**5,787**	**262**	**180**	**-**	**-**
Sales	**7,539**	**217**	**276**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**-**	**899**
U.S. dollars	**-**	**-**	**-**	**U.S. 469**	**U.S. 1,475**
Japanese yen (in billions)	**-**	**-**	**-**	**-**	**-**
Cross-currency	**-**	**-**	**-**	**227/U.S. 157**	**-**
Net unrealized (losses)/gains in the period[4]					
Three months ended June 30, 2009	**$(2)**	**$10**	**$(5)**	**$1**	**$27**
Six months ended June 30, 2009	**$19**	**$(25)**	**$2**	**$2**	**$27**
Net realized gains/(losses) in the period[4]					
Three months ended June 30, 2009	**$20**	**$(39)**	**$2**	**$11**	**$(5)**
Six months ended June 30, 2009	**$30**	**$(13)**	**$(1)**	**$17**	**$(9)**
Maturity dates	**2009-2014**	**2009-2014**	**2009-2010**	**2009-2012**	**2009-2018**
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[2]					
Assets	**$213**	**$2**	**-**	**-**	**$6**
Liabilities	**$(173)**	**$(25)**	**-**	**$(28)**	**$(64)**
Notional Values					
Volumes[3]					
Purchases	**13,159**	**22**	**-**	**-**	**-**
Sales	**14,520**	**-**	**-**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**-**	**-**	**1,325**
Cross-currency	**-**	**-**	**-**	**136/U.S. 100**	**-**
Net realized gains/(losses) in the period[4]					
Three months ended June 30, 2009	**$52**	**$(10)**	**-**	**-**	**$(10)**
Six months ended June 30, 2009	**$78**	**$(20)**	**-**	**-**	**$(17)**
Maturity dates	**2009-2015**	**2009-2012**	**n/a**	**2009-2013**	**2010-2013**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging

relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and six months ended June 30, 2009 were $1 million and $2 million, respectively, and were included in Interest Expense. In second quarter 2009, the Company did not record any amounts in Net Income Applicable to Common Shares related to ineffectiveness for fair value hedges.

(6) Net Income Applicable to Common Shares for the three and six months ended June 30, 2009 included losses of $4 million and gains of $1 million, respectively, for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income Applicable to Common Shares for the three and six months ended June 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2008 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values(1)(4)					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values(4)					
Volumes(2)					
Purchases	4,035	172	410	-	-
Sales	5,491	162	252	-	-
Canadian dollars	-	-	-	-	1,016
U.S. dollars	-	-	-	U.S. 479	U.S. 1,575
Japanese Yen (in billions)	-	-	-	JPY 4.3	-
Cross-currency	-	-	-	227/U.S. 157	-
Net unrealized (losses)/gains in the period(3)					
Three months ended June 30, 2008	$(2)	$7	-	$2	$2
Six months ended June 30, 2008	$(5)	$(11)	-	$(7)	$(2)
Net realized gains/(losses) in the period(3)					
Three months ended June 30, 2008	$8	$(20)	-	$5	$7
Six months ended June 30, 2008	$9	$5	-	$10	$10
Maturity dates(4)	2009-2014	2009-2011	2009	2009-2012	2009-2018
Derivative Financial Instruments in Hedging Relationships(5)(6)					
Fair Values(1)(4)					
Assets	$115	-	-	$2	$8
Liabilities	$(160)	$(18)	-	$(24)	$(122)
Notional Values (4)					
Volumes(2)					
Purchases	8,926	9	-	-	-
Sales	13,113	-	-	-	-
Canadian dollars	-	-	-	-	50
U.S. dollars	-	-	-	U.S. 15	U.S. 1,475
Cross-currency	-	-	-	136/U.S. 100	-
Net realized (losses)/ gains in the period(3)					
Three months ended June 30, 2008	$(37)	$11	-	-	$(3)
Six months ended June 30, 2008	$(38)	$19	-	-	$(2)
Maturity dates(4)	2009-2014	2009-2011	n/a	2009-2013	2009-2019

(1) Fair values equal carrying values.

(2) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(3) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held

for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(4) As at December 31, 2008.

(5) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and notional amounts of $50 million and US$50 million at December 31, 2008. There were no net realized gains or losses on fair value hedges for the three and six months ended June 30, 2008. In second quarter 2008, the Company did not record any amounts in Net Income Applicable to Common Shares related to ineffectiveness for fair value hedges.

(6) Net Income Applicable to Common Shares for the three and six months ended June 30, 2008 included losses of $5 million and $3 million, respectively, for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income Applicable to Common Shares for the three and six months ended June 30, 2008 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Current		
Other current assets	**445**	318
Accounts payable	**(445)**	(298)
Long-term		
Other assets	**165**	191
Deferred amounts	**(396)**	(694)

Other Risks

Additional risks faced by the Company are discussed in the MD&A in TCPL's 2008 Annual Report. These risks remain substantially unchanged since December 31, 2008.

Controls and Procedures

As of June 30, 2009, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of TCPL's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TCPL's disclosure controls and procedures were effective as at June 30, 2009.

During the recent fiscal quarter, there have been no changes in TCPL's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, TCPL's internal control over financial reporting.

During second quarter 2009, TCPL completed its integration of Ravenswood's internal controls over financial reporting.

Outlook

The economic turmoil and deterioration of financial markets in North America is continuing to have a slowing effect on certain aspects of the North American economy. TCPL does not expect this to have a material effect on the Company's financial position, access to capital markets, committed projects or corporate strategy.

Since the disclosure in TCPL's 2008 Annual Report, the Company's earnings outlook for 2009 has declined due to the negative impact of reduced market prices for power on Energy's results. With respect to the Pipelines segment, although the global economic downturn has an impact on throughput on certain pipelines and on some drilling activities, the short-term financial outlook for the Company's Pipelines segment is not expected to be materially impacted as the pipeline assets are generally underpinned by contracts or earn a regulated rate of return.

TCPL completed the issuance of $3.1 billion of long-term debt in first quarter 2009 and approximately $1.0 billion of common shares at the end of 2008. While these offerings will impact future net income applicable to common shares through carrying costs, when combined with $1.8 billion of cash provided by operations in the first half of 2009, they have contributed to a cash balance of $2.8 billion at June 30, 2009 and provided most of the necessary financing for the Company's 2009 capital expenditure program and acquisition of the remaining interest in Keystone. This strategy of strengthening TCPL's liquidity and financial position through its ability to successfully access capital markets in very volatile and uncertain economic times has reduced the Company's future financing risk around its committed growth program. For further information on outlook, refer to the MD&A in TCPL's 2008 Annual Report.

Since December 31, 2008, there have been no changes to TCPL's credit ratings. TransCanada Corporation's issuer rating assigned by Moody's Investors Service (Moody's) is Baa1 with a stable outlook. TCPL's senior unsecured debt is rated A with a stable outlook by DBRS, A3 with a stable outlook by Moody's and A- with a stable outlook by Standard and Poor's.

Recent Developments

Pipelines

Keystone

On June 16, 2009, TCPL announced an agreement to acquire ConocoPhillips' remaining interest in Keystone for approximately US$550 million plus the assumption of approximately US$200 million of short-term indebtedness. The purchase price reflects ConocoPhillips' capital contributions to date and includes an allowance for funds used during construction. TCPL will also assume responsibility for ConocoPhillips' share of the capital investment required to complete the project, resulting in an incremental commitment of approximately US$1.7 billion through the end of 2012. The transaction is expected to close in third quarter 2009, subject to the receipt of certain regulatory approvals. At June 30, 2009, TCPL's equity ownership in the Keystone partnerships was 77 per cent.

The first phase of Keystone is currently under construction. It will extend 3,456 km (2,148 miles) from Hardisty, Alberta to serve markets in Wood River and Patoka, Illinois, and have an initial nominal capacity of 435,000 barrels per day (bbl/d). Commissioning of this segment is expected to commence in late 2009 with commercial operations to follow in early 2010. At July 30, 2009, the first phase was approximately 80 per cent complete. The pipeline is expected to subsequently be expanded to a nominal capacity of 590,000 bbl/d and extend to Cushing, Oklahoma. Commissioning of the Cushing segment is expected to commence in late 2010.

Keystone is also currently seeking the necessary regulatory approvals in Canada and the U.S. to construct and operate an expansion and extension of the pipeline that will provide additional capacity of 500,000 bbl/d from Western Canada to the U.S. Gulf Coast in 2012. This Keystone expansion will extend 2,720 km (1,690 miles) from Hardisty, Alberta to a delivery point near existing terminals in Port Arthur, Texas. Construction of the expansion facilities is anticipated to commence in 2010 following the receipt of the necessary regulatory approvals.

The total capital cost of Keystone is expected to be approximately US$12 billion. Approximately US$3 billion has been spent to date with the remaining approximately US$9 billion expected to be incurred by the end of 2012. Capital costs related to the construction of Keystone are subject to capital cost risk-and-reward sharing mechanisms with its customers.

Keystone is expected to begin generating EBITDA in first quarter 2010 when commercial operations to Wood River and Patoka, Illinois commence, with EBITDA increasing through 2011 and 2012 as subsequent phases are placed in service. Based on current long-term commitments of 910,000 bbl/d, Keystone is expected to generate EBITDA of approximately US$1.2 billion in 2013, its first full year of commercial operation serving both the U.S. Midwest and Gulf Coast markets. If volumes increase to 1.1 million bbl/d, the full commercial design of the system, Keystone would generate approximately US$1.5 billion of annual EBITDA. In the future, Keystone can be economically expanded from 1.1 million bbl/d to 1.5 million bbl/d in response to additional market demand.

Alaska

On June 11, 2009, TCPL and ExxonMobil Corporation reached an agreement to work together to progress TCPL's Alaska pipeline project. With a forecasted capital cost of US$26 billion (2007 estimate in 2007 dollars), the project would provide a variety of benefits to Alaska and Canada, as well as the rest of the U.S., including substantial revenues, jobs, business opportunities and new, long-term stable supplies of natural gas.

The Alaska pipeline project continues to move forward with project development, including engineering, environmental reviews, Alaska Native and Canadian Aboriginal engagement, and commercial work to conclude an initial binding open season by July 2010. Subject to the completion of a successful open season, construction of the approximately 2,700 km (1,700 miles), 4.5 Bcf per day pipeline would begin in 2016, once environmental and regulatory approvals are received, and the pipeline would begin transporting natural gas in 2018.

North Baja

On July 1, 2009, TCPL sold the North Baja pipeline to PipeLines LP. As part of the transaction, TCPL agreed to amend its incentive distribution rights with PipeLines LP. TCPL received aggregate consideration totalling approximately US$395 million from PipeLines LP, including approximately US$200 million in cash and 6,371,680 common units of PipeLines LP. PipeLines LP utilized US$170 million of its US$250 million committed and available bank facility to fund this transaction. TCPL's ownership in PipeLines LP increased to 42.6 per cent as a result of this transaction. The Company will continue to operate the North Baja pipeline.

Alberta System

The Company has initiated discussions with stakeholders to transfer the Alberta System's 2008 – 2009 Revenue Requirement Settlement to NEB jurisdiction. Following these discussions, TCPL will apply to the NEB for approval of final 2009 tolls.

In April 2009, TCPL submitted an application to the NEB for approval to construct and operate the Groundbirch pipeline, which comprises a 77 km (48 miles) natural gas pipeline and related facilities including meter stations and valve sites. The Groundbirch pipeline is an extension of the Alberta System which is expected to connect natural gas supply primarily from the Montney shale gas region in northeast B.C. to existing infrastructure in northwest Alberta. In June 2009, the NEB announced that it will hold a public hearing process on the application. The oral part of the hearing is scheduled to begin November 17, 2009. Subject to regulatory approvals, construction of the Groundbirch pipeline is expected to commence in July 2010 with final completion anticipated in November 2010.

In May 2009, TCPL filed a Project Description with the NEB to construct the Horn River natural gas pipeline. The Horn River pipeline is a proposed extension of the Alberta System to service the Horn River shale gas region in northeast B.C. Horn River producers have recently notified TCPL that they are extending their construction schedule for upstream production facilities which will enhance their ability to manage project costs. Therefore, TCPL will delay the in-service date of the Horn River pipeline from 2011 to 2012.

Guadalajara

In May 2009, TCPL entered into a contract to build, own and operate a US$320 million pipeline in Mexico, which is supported by a 25-year contract for its entire capacity with Comisión Federal de Electricidad, Mexico's state-owned electric company.

The proposed Guadalajara pipeline will extend 310 km (193 miles) from an LNG terminal under construction near Manzanillo, Mexico, to Guadalajara and is expected to be capable of transporting 500 million cubic feet per day of natural gas. The Company expects to complete most of the construction in 2010 with a targeted in-service date of March 2011.

TQM

In June 2009, the NEB approved TQM's final tolls for 2007 and 2008, consisting of a 6.4 per cent after-tax weighted average cost of capital on its cost of capital application for the years 2007 and 2008. This decision equates to a 9.85 per cent return on 40 per cent deemed common equity in 2007 and a 9.75 per cent return on 40 per cent deemed common equity in 2008. The decision granted TQM an aggregate return on capital, leaving it to TQM to choose its optimal capital structure. TQM expects to recover the variance between interim and final tolls for 2007 and 2008 in third quarter 2009. The net earnings impact related to the variance was recorded by TQM in first quarter 2009.

Ventures LP

In May 2009, the AUC announced that it intends to seek an Order in Council allowing it to set rates on the Ventures LP pipeline. Ventures LP has initiated appeal proceedings of this decision and the application to the court is expected to commence in third quarter 2009.

Bison

The Bison pipeline project is expected to be in service November 2010. The regulatory approval process and the engineering and procurement work are progressing as planned.

Review of NEB ROE Formula

In May 2009, the NEB received comments on whether it should initiate a multi-pipeline review of the RH-2-94 Decision pursuant to the *National Energy Board Act (Canada)* (NEB Act), which established an ROE formula tied to 10 year and 30 year Government of Canada bond rates, that has formed the basis of determining tolls for pipelines under NEB jurisdiction since January 1, 1995. Based on comments submitted, the NEB has decided to initiate a review of this decision by seeking comments on the continuing applicability of the decision by September 18, 2009. TCPL's position, included in its May 2009 letter to the NEB, is that the decision should be rescinded on a prospective basis.

Land Matters Consultation Initiative

In May 2009, the NEB issued its RH-2-2008 Decision on the Land Matters Consultation Initiative Stream 3 with respect to financial issues related to pipeline abandonment. All pipeline companies regulated under the NEB Act will be required to comply with the framework and action plan set out in the decision. The NEB's goal is to have pipeline companies begin collecting and setting aside funds to cover future abandonment costs no later than mid-2014. There are several filing deadlines in the action plan with which NEB regulated pipeline companies have to comply, including deadlines for the preparation and filing of an estimate of the abandonment costs, developing a proposal for collection of funds through tolls or some other satisfactory method and developing a proposed process to set aside the funds collected. As a result of this decision, TCPL has initiated a project to estimate the abandonment costs on its NEB regulated pipelines to be filed with the NEB for approval by May 31, 2011.

Energy

Bruce Power

On July 6, 2009, Bruce Power and the OPA amended certain terms and conditions of commercial agreements in place between the two parties.

Payments received pursuant to the Bruce B floor price mechanism were previously subject to repayment during the entire term of the contract, dependent on future periods' spot prices. The contract with the OPA was amended such that, beginning in 2009, annual payments received will not be subject to repayment in future years.

Other changes to the contract with the OPA include the removal of a support payment cap for Bruce A. The cumulative support payments received by Bruce A, which are equal to the difference between the fixed prices under the OPA contract and spot market prices, were originally capped at $575 million until both Units 1 and 2 were restarted. Under the amendment, should either of the restarted Units 1 and 2 not be placed into commercial service by December 31, 2011, Bruce A will receive spot prices on all of its output until the restart of both units is complete, after which Bruce A prices will return to the then prevailing contract levels.

The OPA contract was also amended, commencing July 6, 2009, to provide for deemed generation payments to Bruce Power at contract prices under circumstances when Bruce Power generation is reduced due to system curtailments on the Independent Electricity System Operator controlled grid in Ontario.

Additionally, the capital cost sharing mechanism for the restart and refurbishment of Bruce A Units 1 and 2 was amended such that the OPA will not share in any cost overruns over $3.4 billion. Previously the OPA was responsible for 25 per cent of cost overruns above $3.4 billion through a future adjustment to the fixed price paid to Bruce Power for power generated by the Bruce A units. Although Bruce Power estimates the total capital costs to be $3.4 billion, the Company's current view is that costs may exceed that amount by up to ten per cent. Units 1 and 2 are expected to return to service by the end of 2010.

Cartier Wind

On June 10, 2009, the Government of Québec approved the construction of the 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms. Both wind farms are expected to be operational by 2012, representing an investment of approximately $340 million. These are the fourth and fifth Québec - based wind farms either in place or under development by Cartier Wind, which is 62 per cent owned by TCPL.

Kibby Wind

TCPL continues to advance construction on the Kibby Wind power project, including the installation of 22 turbines which are expected to be completed in the summer of 2009. Kibby Wind is expected to have the capacity to produce 132 MW of power when complete, with commissioning of the first phase of the project to begin in late 2009.

Coolidge

TCPL expects to begin construction of the US$500 million Coolidge generating station in August 2009. The 575 MW, simple-cycle, natural gas-fired peaking power facility is expected to be in service in second quarter 2011.

Bécancour

On June 29, 2009, TCPL entered into an agreement with Hydro-Québec to continue to suspend all electricity generation from the Bécancour power plant throughout 2010. Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TCPL will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Ravenswood

Ravenswood's 972 MW Unit 30 returned to service May 17, 2009 following an extensive outage. The Company continues to work with its insurers with respect to claims for both the physical damage and business interruption losses associated with the outage.

In 2010, the Company expects capacity prices in the New York City Zone J, in which Ravenswood operates, to return to historic levels, which were somewhat higher than current rates. This increase in capacity prices will be driven in part by the long-planned retirement of a power generating facility owned by the New York Power Authority, which is scheduled to occur in January 2010.

Share Information

As at June 30, 2009, TCPL had 602 million issued and outstanding common shares.

Selected Quarterly Consolidated Financial Data[1]

(unaudited) (millions of dollars except per share amounts)	2009		2008				2007	
	Second	**First**	Fourth	Third	Second	First	Fourth	Third
Revenues	**2,127**	**2,380**	2,332	2,137	2,017	2,133	2,189	2,187
Net Income Applicable to Common Shares	**311**	**330**	274	383	318	445	373	320
Share Statistics								
Net income applicable to common shares per share – Basic and Diluted	**$0.52**	**$0.55**	$0.47	$0.70	$0.60	$0.84	$0.71	$0.61

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation.

Factors Impacting Quarterly Financial Information

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that impacted the last eight quarters' EBIT and Net Income Applicable to Common Shares are as follows:

- Second quarter 2009, Energy's EBIT included net unrealized losses of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Energy's EBIT also included contributions from Portlands Energy, which was placed in service in April 2009.

- First quarter 2009, Energy's EBIT included net unrealized losses of $13 million pre-tax ($9 million after tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.

- Fourth quarter 2008, Energy's EBIT included net unrealized gains of $7 million pre-tax ($6 million after tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. Corporate's EBIT included net unrealized losses of $57 million pre-tax ($39 million after tax) for changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates but which do not qualify as hedges for accounting purposes.

- Third quarter 2008, Energy's EBIT included contributions from the August 26, 2008 acquisition of Ravenswood. Net Income Applicable to Common Shares included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.

- Second quarter 2008, Energy's EBIT included net unrealized gains of $12 million pre-tax ($8 million after tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts. In addition, Western Power's revenues and EBIT increased due to higher overall realized prices and market heat rates in Alberta.

- First quarter 2008, Pipelines' EBIT included $279 million pre-tax ($152 million after tax) from the Calpine bankruptcy settlements received by GTN and Portland, and proceeds of $17 million pre-tax ($10 million after tax) from a lawsuit settlement. Energy's EBIT included a writedown of $41 million pre-tax ($27 million after tax) of costs related to the Broadwater LNG project and net unrealized losses of $17 million pre-tax ($12 million after tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.

- Fourth quarter 2007, Net Income Applicable to Common Shares included $56 million of favourable income tax adjustments resulting from reductions in Canadian federal income tax rates and other legislative changes. Energy's EBIT increased due to a $16 million pre-tax ($14 million after tax) gain on sale of land previously held for development. Pipelines' EBIT increased as a result of recording incremental earnings related to a rate case settlement reached for the GTN System, effective January 1, 2007. Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts.

- Third quarter 2007, Net Income Applicable to Common Shares included $15 million of favourable income tax reassessments and associated interest income relating to prior years.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Revenues	**2,127**	2,017	**4,507**	4,150
Operating and Other Expenses/(Income)				
Plant operating costs and other	**828**	733	**1,665**	1,431
Commodity purchases resold	**299**	333	**729**	729
Other income	**(10)**	(9)	**(15)**	(37)
Calpine bankruptcy settlements	**-**	-	**-**	(279)
Writedown of Broadwater LNG project costs	**-**	-	**-**	41
	1,117	1,057	**2,379**	1,885
	1,010	960	**2,128**	2,265
Depreciation and amortization	**345**	315	**691**	625
	665	645	**1,437**	1,640
Financial Charges/(Income)				
Interest expense	**264**	191	**565**	415
Financial charges of joint ventures	**16**	17	**30**	33
Interest income and other	**(34)**	(20)	**(56)**	(31)
	246	188	**539**	417
Income before Income Taxes and Non-Controlling Interests	**419**	457	**898**	1,223
Income Taxes				
Current	**37**	103	**91**	349
Future	**58**	19	**118**	23
	95	122	**209**	372
Non-Controlling Interests				
Non-controlling interest in PipeLines LP	**8**	13	**32**	34
Non-controlling interest in Portland	**-**	(1)	**5**	43
	8	12	**37**	77
Net Income	**316**	323	**652**	774
Preferred Share Dividends	**5**	5	**11**	11
Net Income Applicable to Common Shares	**311**	318	**641**	763

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Cash Generated From Operations				
Net income	**316**	323	**652**	774
Depreciation and amortization	**345**	315	**691**	625
Future income taxes	**58**	19	**118**	23
Non-controlling interests	**8**	12	**37**	77
Employee future benefits funding (in excess of)/ lower than expense	**(23)**	(7)	**(57)**	13
Writedown of Broadwater LNG project costs	**-**	-	**-**	41
Other	**(18)**	6	**5**	32
	686	668	**1,446**	1,585
Decrease/(increase) in operating working capital	**305**	(126)	**396**	(104)
Net cash provided by operations	**991**	542	**1,842**	1,481
Investing Activities				
Capital expenditures	**(1,263)**	(633)	**(2,386)**	(1,093)
Acquisitions, net of cash acquired	**(115)**	(2)	**(249)**	(4)
Deferred amounts and other	**(154)**	(1)	**(324)**	111
Net cash used in investing activities	**(1,532)**	(636)	**(2,959)**	(986)
Financing Activities				
Dividends on common and preferred shares	**(239)**	(200)	**(468)**	(390)
Advances received from/(repaid to) parent	**1,065**	14	**1,057**	(366)
Distributions paid to non-controlling interests	**(19)**	(60)	**(40)**	(75)
Notes payable issued/(repaid), net	**233**	754	**(684)**	1,090
Long-term debt issued, net of issue costs	**-**	-	**3,060**	112
Reduction of long-term debt	**(18)**	(379)	**(500)**	(773)
Long-term debt of joint ventures issued	**92**	17	**108**	34
Reduction of long-term debt of joint ventures	**(33)**	(28)	**(56)**	(57)
Common shares issued	**52**	69	**126**	125
Net cash provided by/(used in) financing activities	**1,133**	187	**2,603**	(300)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(60)**	(3)	**(34)**	20
Increase in Cash and Cash Equivalents	**532**	90	**1,452**	215
Cash and Cash Equivalents				
Beginning of period	**2,220**	629	**1,300**	504
Cash and Cash Equivalents				
End of period	**2,752**	719	**2,752**	719
Supplementary Cash Flow Information				
Income taxes paid	**56**	145	**113**	309
Interest paid	**274**	277	**537**	479

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	**2,752**	1,300
Accounts receivable	**889**	1,280
Due from TransCanada Corporation	**1,858**	1,529
Inventories	**488**	489
Other	**858**	523
	6,845	5,121
Plant, Property and Equipment	**30,587**	29,189
Goodwill	**4,169**	4,397
Regulatory Assets	**1,594**	201
Other Assets	**2,206**	2,027
	45,401	40,935
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**1,041**	1,702
Accounts payable	**2,292**	1,868
Due to TransCanada Corporation	**3,207**	1,821
Accrued interest	**418**	361
Current portion of long-term debt	**570**	786
Current portion of long-term debt of joint ventures	**303**	207
	7,831	6,745
Regulatory Liabilities	**490**	551
Deferred Amounts	**860**	1,168
Future Income Taxes	**2,722**	1,253
Long-Term Debt	**17,545**	15,368
Long-Term Debt of Joint Ventures	**796**	869
Junior Subordinated Notes	**1,151**	1,213
	31,395	27,167
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**679**	721
Non-controlling interest in Portland	**85**	84
	764	805
Shareholders' Equity	**13,242**	12,963
	45,401	40,935

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended June 30 **2009**	2008	Six months ended June 30 **2009**	2008
Net Income	**316**	323	**652**	774
Other Comprehensive Income/(Loss), Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(113)**	(14)	**(151)**	39
Change in gains and losses on hedges of investments in foreign operations[2]	**96**	17	**96**	(24)
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**37**	29	**64**	33
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	**(9)**	1	**(5)**	(18)
Other Comprehensive Income/(Loss)	**11**	33	**4**	30
Comprehensive Income	**327**	356	**656**	804

(1) Net of income tax expense of $6 million and nil for the three and six months ended June 30, 2009, respectively (2008 - $5 million expense and $20 million recovery, respectively).

(2) Net of income tax expense of $48 million and $52 million for the three and six months ended June 30, 2009, respectively (2008 - $8 million expense and $14 million recovery, respectively).

(3) Net of income tax expense of $19 million and $16 million for the three and six months ended June 30, 2009, respectively (2008 – expense of $37 million and $49 million, respectively).

(4) Net of income tax recovery of $1 million and nil for the three and six months ended June 30, 2009, respectively (2008 – recovery of $2 million and $11 million, respectively).

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at December 31, 2008	**(379)**	**(93)**	**(472)**
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(151)**	**-**	**(151)**
Change in gains and losses on hedges of investments in foreign operations[2]	**96**	**-**	**96**
Changes in gains and losses on derivative instruments designated as cash flow hedges[3]	**-**	**64**	**64**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][5]	**-**	**(5)**	**(5)**
Balance at June 30, 2009	**(434)**	**(34)**	**(468)**

Balance at December 31, 2007	(361)	(12)	(373)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	39	-	39
Change in gains and losses on hedges of investments in foreign operations[2]	(24)	-	(24)
Changes in gains and losses on derivative instruments designated as cash flow hedges[3]	-	33	33
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	-	(18)	(18)
Balance at June 30, 2008	(346)	3	(343)

(1) Net of income tax of nil for the six months ended June 30, 2009 (2008 - $20 million recovery).
(2) Net of income tax expense of $52 million for the six months ended June 30, 2009 (2008 - $14 million recovery).
(3) Net of income tax expense of $16 million for the six months ended June 30, 2009 (2008 - $49 million expense).
(4) Net of income tax of nil for the six months ended June 30, 2009 (2008 - $11 million recovery).
(5) The amount of gains related to cash flow hedges reported in accumulated other comprehensive income that is expected to be reclassified to net income in the next 12 months is estimated to be $4 million ($10 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

See accompanying notes to the consolidated financial statements.

Consolidated Shareholders' Equity

(unaudited) *(millions of dollars)*	Six months ended June 30 **2009**	2008
Preferred Shares	**389**	389
Common Shares		
Balance at beginning of period	**8,973**	6,554
Proceeds from common shares issued	**126**	125
Balance at end of period	**9,099**	6,679
Contributed Surplus		
Balance at beginning of period	**284**	281
Other	**2**	1
Balance at end of period	**286**	282
Retained Earnings		
Balance at beginning of period	**3,789**	3,202
Net income	**652**	774
Preferred share dividends	**(11)**	(11)
Common share dividends	**(494)**	(403)
Balance at end of period	**3,936**	3,562
Accumulated Other Comprehensive Income		
Balance at beginning of period	**(472)**	(373)
Other comprehensive income	**4**	30
Balance at end of period	**(468)**	(343)
	3,468	3,219
Total Shareholders' Equity	**13,242**	10,569

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

(Unaudited)

1. Significant Accounting Policies

The consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The accounting policies applied are consistent with those outlined in TCPL's annual audited Consolidated Financial Statements for the year ended December 31, 2008, except as described in Note 2. These Consolidated Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2008 audited Consolidated Financial Statements included in TCPL's 2008 Annual Report. Unless otherwise indicated, "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses as the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

2. Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TCPL's 2008 Annual Report except as follows:

2009 Accounting Changes

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption was withdrawn from the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1100 "Generally Accepted Accounting Principles", which permitted the recognition and measurement of assets and liabilities arising from rate regulation. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company chose to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". As a result, TCPL retained its current method of accounting for its rate-regulated operations, except that TCPL is required to recognize future income tax assets and liabilities, instead of using the taxes payable method, and records an offsetting adjustment to regulatory assets and liabilities. As a result of adopting this accounting change, additional future income tax liabilities and a regulatory asset in the amount of $1.4 billion were recorded January 1, 2009 in each of Future Income Taxes and Other Assets, respectively.

Adjustments to the 2009 financial statements have been made in accordance with the transitional provisions for Section 3465, which required a cumulative adjustment in the current period to future income taxes and a regulatory asset. Restatement of prior periods' financial statements was not permitted under Section 3465.

Intangible Assets

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". Section 3064 gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. In addition, Section 3450 "Research and Development Costs" was withdrawn from the Handbook. Adopting this accounting change did not have a material effect on the Company's financial statements.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, the Company adopted the accounting provisions of Emerging Issues Committee (EIC) Abstract EIC 173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". Under EIC 173 an entity's own credit risk and the credit risk of its counterparties is taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adopting this accounting change did not have a material effect on the Company's financial statements.

Future Accounting Changes

International Financial Reporting Standards

The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Company will prepare its financial statements under IFRS commencing January 1, 2011.

Under existing Canadian GAAP, TCPL follows specific accounting policies unique to a rate-regulated business. TCPL is actively monitoring developments regarding potential future guidance on the applicability of certain aspects of rate-regulated accounting under IFRS. Developments in this area could have a significant effect on the scope of the Company's IFRS project and on TCPL's financial results under IFRS. On

July 23, 2009, the IASB issued an exposure draft "Rate-regulated Activities" and the Company is assessing the impact of this exposure draft on TCPL.

At the current stage of its IFRS project, TCPL cannot reasonably determine the full impact that adopting IFRS would have on its financial position and future results.

Financial Instruments Disclosure

The CICA implemented revisions to Handbook Section 3862 "Financial Instruments – Disclosures" for fiscal years ending after September 30, 2009. These revisions are intended to align the disclosure requirements for financial instruments to the maximum extent possible with the disclosure required under IFRS. These revisions require additional disclosure based on a three level hierarchy that reflects the significance of inputs used in measuring fair value. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of assets and liabilities included in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Fair values of assets and liabilities included in Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These changes will be applied by TCPL effective December 31, 2009.

3. Segmented Information

Effective January 1, 2009, TCPL revised its presentation of certain income and expense items in the Consolidated Statement of Income to better reflect the operating and financing structure of the Company. To conform with the new presentation, certain of the income and expense amounts pertaining to operations that were previously classified on the Consolidated Income Statement as Other Expenses/(Income) are now included in Operating and Other Expenses/(Income). Depreciation expense has been redefined as Depreciation and Amortization expense and includes amortization of $15 million and $29 million in the three and six month periods ended June 30, 2009, respectively (2008 - $15 million and $29 million, respectively), for power purchase arrangements, which were previously included in Commodity Purchases Resold. Support services costs previously allocated to Pipelines and Energy of $31 million and $62 million in the three and six month periods ended June 30, 2009 (2008 - $25 million and $51 million, respectively), are now included in Corporate. In addition, amounts related to interest expense and financial charges of joint ventures, interest income and other, income taxes, and non-controlling interests and preferred share dividends are no longer reported on a segmented basis. Segmented information has been retroactively reclassified to reflect all changes. These changes had no impact on Consolidated Net Income Applicable to Common Shares.

Three months ended June 30 *(unaudited)* *(millions of dollars)*	Pipelines 2009	Pipelines 2008	Energy 2009	Energy 2008	Corporate 2009	Corporate 2008	Total 2009	Total 2008
Revenues	**1,142**	1,100	**985**	917	**-**	-	**2,127**	2,017
Plant operating costs and other	**(403)**	(393)	**(394)**	(313)	**(31)**	(27)	**(828)**	(733)
Commodity purchases resold	**-**	-	**(299)**	(333)	**-**	-	**(299)**	(333)
Other income	**8**	7	**2**	1	**-**	1	**10**	9
	747	714	**294**	272	**(31)**	(26)	**1,010**	960
Depreciation and amortization	**(258)**	(257)	**(87)**	(58)	**-**	-	**(345)**	(315)
	489	457	**207**	214	**(31)**	(26)	**665**	645
Interest expense							**(264)**	(191)
Financial charges of joint ventures							**(16)**	(17)
Interest income and other							**34**	20
Income taxes							**(95)**	(122)
Non-controlling interests and preferred share dividends							**(13)**	(17)
Net Income Applicable to Common Shares							**311**	318

Six months ended June 30 *(unaudited)* *(millions of dollars)*	Pipelines 2009	Pipelines 2008	Energy 2009	Energy 2008	Corporate 2009	Corporate 2008	Total 2009	Total 2008
Revenues	**2,406**	2,276	**2,101**	1,874	**-**	-	**4,507**	4,150
Plant operating costs and other	**(800)**	(773)	**(803)**	(604)	**(62)**	(54)	**(1,665)**	(1,431)
Commodity purchases resold	**-**	-	**(729)**	(729)	**-**	-	**(729)**	(729)
Other income	**12**	30	**2**	1	**1**	6	**15**	37
Calpine bankruptcy settlements	**-**	279	**-**	-	**-**	-	**-**	279
Writedown of Broadwater LNG project costs	**-**	-	**-**	(41)	**-**	-	**-**	(41)
	1,618	1,812	**571**	501	**(61)**	(48)	**2,128**	2,265
Depreciation and amortization	**(518)**	(511)	**(173)**	(114)	**-**	-	**(691)**	(625)
	1,100	1,301	**398**	387	**(61)**	(48)	**1,437**	1,640
Interest expense							**(565)**	(415)
Financial charges of joint ventures							**(30)**	(33)
Interest income and other							**56**	31
Income taxes							**(209)**	(372)
Non-controlling interests and preferred share dividends							**(48)**	(88)
Net Income Applicable to Common Shares							**641**	763

For the years ended December 31, 2008 and 2007, segmented information has been retroactively reclassified to reflect all changes.

For the year ended December 31 *(unaudited)* *(millions of dollars)*	Pipelines 2008	Pipelines 2007	Energy 2008	Energy 2007	Corporate 2008	Corporate 2007	Total 2008	Total 2007
Revenues	4,650	4,712	3,969	4,116	-	-	8,619	8,828
Plant operating costs and other	(1,645)	(1,590)	(1,307)	(1,336)	(110)	(104)	(3,062)	(3,030)
Commodity purchases resold	-	(72)	(1,453)	(1,829)	-	-	(1,453)	(1,901)
Calpine bankruptcy settlements	279	-	-	16	-	-	279	16
Writedown of Broadwater LNG project costs	-	-	(41)	-	-	-	(41)	-
Other income	31	27	1	3	6	2	38	32
	3,315	3,077	1,169	970	(104)	(102)	4,380	3,945
Depreciation and amortization	(989)	(1,021)	(258)	(216)	-	-	(1,247)	(1,237)
	2,326	2,056	911	754	(104)	(102)	3,133	2,708
Interest expense							(962)	(961)
Financial charges of joint ventures							(72)	(75)
Interest income and other							42	118
Income taxes							(591)	(483)
Non-controlling interests and preferred share dividends							(130)	(97)
Net Income Applicable to Common Shares							1,420	1,210

Total Assets

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Pipelines	**27,813**	25,020
Energy	**12,259**	12,006
Corporate	**5,329**	3,909
	45,401	40,935

4. Long-Term Debt

On April 23, 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes shelf prospectus, which expired in April 2009. No amounts have been issued under this shelf prospectus.

In February 2009, TCPL issued Medium-Term Notes of $300 million and $400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued under the $1.5 billion debt shelf prospectus filed in March 2007.

In January 2009, TCPL issued Senior Unsecured Notes of US$750 million and US$1.25 billion maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued under a US$3.0 billion debt shelf prospectus filed in January 2009, which now has capacity of US$1.0 billion remaining.

In the three and six months ended June 30, 2009, the Company capitalized interest related to capital projects of $63 million and $117 million, respectively (2008 - $32 million and $59 million).

5. Share Capital

In the three and six months ended June 30, 2009, TCPL issued 1.7 million and 3.9 million common shares, respectively (2008 – 1.9 million and 3.4 million common shares, respectively), to TransCanada Corporation (TransCanada) for proceeds of approximately $52 million and $126 million, respectively (2008 - $69 million and $125 million, respectively).

6. Financial Instruments and Risk Management

TCPL continues to manage and monitor its exposure to market, counterparty credit and liquidity risk.

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted 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 assets. Letters of credit and cash are the primary types of security provided to support these amounts. The Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At June 30, 2009, there were no significant amounts past due or impaired.

As the uncertainty in the global financial markets persists, TCPL continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TCPL must balance its market and counterparty credit risks when making business decisions.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its open liquid positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. TCPL's consolidated VaR was $14 million at June 30, 2009 (December 31, 2008 – $23 million). The decrease from December 31, 2008 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

Natural Gas Inventory

At June 30, 2009, the fair value of proprietary natural gas inventory held in storage as measured using a weighted average of forward prices for the following four months less selling costs was $44 million (December 31, 2008 - $76 million). Prior to second quarter 2009, inventory was measured using the one-month forward price. The impact of this change was insignificant.

The change in fair value of proprietary natural gas inventory in the three and six months ended June 30, 2009 resulted in pre-tax net unrealized losses of $6 million and $29 million, respectively, which were recorded as a decrease to Revenues and Inventories (gains of $42 million and $102 million for the three and six months ended June 30, 2008). The net change in fair value of natural gas forward purchase and sales contracts in the three and six months ended June 30, 2009 resulted in a pre-tax net unrealized loss of $1 million and a pre-tax net unrealized gain of $9 million (losses of $30 million and $107 million for the three and six months ended June 30, 2008), respectively, which were included in Revenues.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange forward contracts and options. At June 30, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $8.8 billion (US$7.6 billion) and a fair value of $9.2 billion (US$7.9 billion). At June 30, 2009, Deferred Amounts included $124 million for the fair value of derivatives used to hedge the Company's net U.S. dollar investment in foreign operations.

Information for the derivatives used to hedge the Company's net investment in its self-sustaining foreign operations is as follows:

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**June 30, 2009** **Fair Value[1]**	**June 30, 2009** **Notional or Principal Amount**	December 31, 2008 Fair Value[1]	December 31, 2008 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)[2]	**(116)**	**U.S. 1,450**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2009)[2]	**(3)**	**U.S. 100**	(42)	U.S. 2,152
U.S. dollar options (maturing 2009)[2]	**(5)**	**U.S. 300**	6	U.S. 300
	(124)	**U.S. 1,850**	(254)	U.S. 4,102

(1) Fair values equal carrying values.
(2) As at June 30, 2009.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

(unaudited) *(millions of dollars)*	**June 30, 2009** Carrying Amount	Fair Value	December 31, 2008 Carrying Amount	Fair Value
Financial Assets(1)				
Cash and cash equivalents	**2,752**	**2,752**	1,300	1,300
Accounts receivable and other assets(2)(3)	**1,036**	**1,036**	1,404	1,404
Due from TransCanada Corporation	**1,858**	**1,858**	1,529	1,529
Available-for-sale assets(2)	**23**	**23**	27	27
	5,669	**5,669**	4,260	4,260
Financial Liabilities(1)(3)				
Notes payable	**1,041**	**1,041**	1,702	1,702
Accounts payable and deferred amounts(4)	**1,587**	**1,587**	1,364	1,364
Due to TransCanada Corporation	**3,207**	**3,207**	1,821	1,821
Accrued interest	**418**	**418**	361	361
Long-term debt and junior subordinated notes	**19,266**	**21,174**	17,367	16,152
Long-term debt of joint ventures	**1,099**	**1,122**	1,076	1,052
	26,618	**28,549**	23,691	22,452

(1) Consolidated Net Income Applicable to Common Shares in 2009 and 2008 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

(2) At June 30, 2009, the Consolidated Balance Sheet included financial assets of $889 million (December 31, 2008 – $1,257 million) in Accounts Receivable and $170 million (December 31, 2008 - $174 million) in Other Assets.

(3) Recorded at amortized cost.

(4) At June 30, 2009, the Consolidated Balance Sheet included financial liabilities of $1,569 million (December 31, 2008 – $1,342 million) in Accounts Payable and $18 million (December 31, 2008 - $22 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

June 30, 2009 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]					
Fair Values[2]					
Assets	**$155**	**$174**	**$6**	**$16**	**$38**
Liabilities	**$(90)**	**$(206)**	**$(4)**	**$(50)**	**$(77)**
Notional Values					
Volumes[3]					
Purchases	**5,787**	**262**	**180**	**-**	**-**
Sales	**7,539**	**217**	**276**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**-**	**899**
U.S. dollars	**-**	**-**	**-**	**U.S. 469**	**U.S. 1,475**
Japanese yen (in billions)	**-**	**-**	**-**	**-**	**-**
Cross-currency	**-**	**-**	**-**	**227/U.S. 157**	**-**
Net unrealized (losses)/gains in the period[4]					
Three months ended June 30, 2009	**$(2)**	**$10**	**$(5)**	**$1**	**$27**
Six months ended June 30, 2009	**$19**	**$(25)**	**$2**	**$2**	**$27**
Net realized gains/(losses) in the period[4]					
Three months ended June 30, 2009	**$20**	**$(39)**	**$2**	**$11**	**$(5)**
Six months ended June 30, 2009	**$30**	**$(13)**	**$(1)**	**$17**	**$(9)**
Maturity dates	**2009-2014**	**2009-2014**	**2009-2010**	**2009-2012**	**2009-2018**
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[2]					
Assets	**$213**	**$2**	**-**	**-**	**$6**
Liabilities	**$(173)**	**$(25)**	**-**	**$(28)**	**$(64)**
Notional Values					
Volumes[3]					
Purchases	**13,159**	**22**	**-**	**-**	**-**
Sales	**14,520**	**-**	**-**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**-**	**-**	**1,325**
Cross-currency	**-**	**-**	**-**	**136/U.S. 100**	**-**
Net realized gains/(losses) in the period[4]					
Three months ended June 30, 2009	**$52**	**$(10)**	**-**	**-**	**$(10)**
Six months ended June 30, 2009	**$78**	**$(20)**	**-**	**-**	**$(17)**
Maturity dates	**2009-2015**	**2009-2012**	**n/a**	**2009-2013**	**2010-2013**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and six months ended June 30, 2009 were $1 million and $2 million, respectively, and were included in Interest Expense. In second quarter 2009, the Company did not record any amounts in Net Income Applicable to Common Shares related to ineffectiveness for fair value hedges.

(6) Net Income Applicable to Common Shares for the three and six months ended June 30, 2009 included losses of $4 million and gains of $1 million, respectively, for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income Applicable to Common Shares for the three and six months ended June 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2008 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[1][4]					
Assets	$132	$144	$10	$41	$57
Liabilities	$(82)	$(150)	$(10)	$(55)	$(117)
Notional Values[4]					
Volumes[2]					
Purchases	4,035	172	410	-	-
Sales	5,491	162	252	-	-
Canadian dollars	-	-	-	-	1,016
U.S. dollars	-	-	-	U.S. 479	U.S. 1,575
Japanese Yen (in billions)	-	-	-	JPY 4.3	-
Cross-currency	-	-	-	227/U.S. 157	-
Net unrealized (losses)/gains in the period[3]					
Three months ended June 30, 2008	$(2)	$7	-	$2	$2
Six months ended June 30, 2008	$(5)	$(11)	-	$(7)	$(2)
Net realized gains/(losses) in the period[3]					
Three months ended June 30, 2008	$8	$(20)	-	$5	$7
Six months ended June 30, 2008	$9	$5	-	$10	$10
Maturity dates[4]	2009-2014	2009-2011	2009	2009-2012	2009-2018
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[1][4]					
Assets	$115	-	-	$2	$8
Liabilities	$(160)	$(18)	-	$(24)	$(122)
Notional Values [4]					
Volumes[2]					
Purchases	8,926	9	-	-	-
Sales	13,113	-	-	-	-
Canadian dollars	-	-	-	-	50
U.S. dollars	-	-	-	U.S. 15	U.S. 1,475
Cross-currency	-	-	-	136/U.S. 100	-
Net realized (losses)/ gains in the period[3]					
Three months ended June 30, 2008	$(37)	$11	-	-	$(3)
Six months ended June 30, 2008	$(38)	$19	-	-	$(2)
Maturity dates[4]	2009-2014	2009-2011	n/a	2009-2013	2009-2019

(1) Fair values equal carrying values.
(2) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.
(3) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.
(4) As at December 31, 2008.
(5) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments

designated as fair value hedges with a fair value of $8 million and notional amounts of $50 million and US$50 million at December 31, 2008. There were no net realized gains or losses on fair value hedges for the three and six months ended June 30, 2008. In second quarter 2008, the Company did not record any amounts in Net Income Applicable to Common Shares related to ineffectiveness for fair value hedges.

(6) Net Income Applicable to Common Shares for the three and six months ended June 30, 2008 included losses of $5 million and $3 million, respectively, for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income Applicable to Common Shares for the three and six months ended June 30, 2008 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

(unaudited) *(millions of dollars)*	**June 30, 2009**	December 31, 2008
Current		
Other current assets	**445**	318
Accounts payable	**(445)**	(298)
Long-term		
Other assets	**165**	191
Deferred amounts	**(396)**	(694)

7. Employee Future Benefits

The net benefit plan expense for the Company's defined benefit pension plans and other post-employment benefit plans is as follows:

Three months ended June 30 *(unaudited)* *(millions of dollars)*	Pension Benefit Plans **2009**	 2008	Other Benefit Plans **2009**	 2008
Current service cost	**12**	12	**1**	1
Interest cost	**22**	20	**2**	2
Expected return on plan assets	**(26)**	(23)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**1**	5	**1**	1
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**10**	15	**4**	4

Six months ended June 30 *(unaudited)* *(millions of dollars)*	Pension Benefit Plans **2009**	 2008	Other Benefit Plans **2009**	 2008
Current service cost	**23**	25	**1**	1
Interest cost	**45**	39	**4**	4
Expected return on plan assets	**(51)**	(46)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**2**	9	**1**	1
Amortization of past service costs	**2**	2	**-**	-
Net benefit cost recognized	**21**	29	**6**	6

8. Acquisition

On June 16, 2009, TCPL announced that it will acquire ConocoPhillips' remaining interest in Keystone for approximately US$550 million plus the assumption of approximately US$200 million of short-term indebtedness. The purchase price reflects ConocoPhillips' capital contributions to date and includes an allowance for funds used during construction. The transaction is expected to close in third quarter 2009, subject to the receipt of certain regulatory approvals. At June 30, 2009, TCPL's equity ownership in the Keystone partnerships was approximately 77 per cent.

9. Commitments and Other

The Company has entered into an agreement to acquire ConocoPhillips' remaining interest in Keystone for approximately US$550 million plus the assumption of approximately US$200 million of short-term indebtedness. The transaction is expected to close in third quarter 2009. In addition, TCPL will also assume responsibility for ConocoPhillips' share of the capital investment required to complete the project, which is expected to result in an incremental commitment of US$1.7 billion through the end of 2012.

Amounts received under the Bruce B floor price mechanism in any year are subject to repayment, if spot prices in the remainder of that year increase above the floor price. With respect to 2009, TCPL currently expects spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenue in the first six months of 2009 are expected to be repaid.

10. Subsequent Event

On July 1, 2009, TCPL sold the North Baja pipeline, to PipeLines LP. As part of the transaction, TCPL agreed to amend its incentive distribution rights with PipeLines LP. TCPL received aggregate consideration totalling approximately US$395 million from PipeLines LP, including approximately US$200 million in cash and 6,371,680 common units of PipeLines LP. PipeLines LP utilized US$170 million of its US$250 million committed and available bank facility to fund this transaction. TCPL's ownership in PipeLines LP increased to 42.6 per cent as a result of this transaction.

Subsequent events have been assessed up to July 30, 2009, which is the date the financial statements were issued.

11. Related Party Transactions

In June 2009, the demand revolving credit facility with TransCanada, established in May 2003, was increased to $1.5 billion from $500 million. In June 2009 $1.05 billion was advanced to TCPL under this facility in addition to the $249 million that was advanced to TCPL in February 2009. As at December 31, 2008, $200 million was outstanding under this facility.

In February 2009, an additional $249 million was advanced to TCPL from TransCanada under the demand revolving credit facility established in May 2003.

In February 2009, TransCanada issued a promissory note to a subsidiary of TCPL for $249 million. This promissory note is non-interest bearing and is payable on demand.

TCPL welcomes questions from shareholders and potential investors. Please telephone:

Investor Relations, at (800) 361-6522 (Canada and U.S. Mainland) or direct dial David Moneta/Myles Dougan/Terry Hook at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: Cecily Dobson/Terry Cunha (403) 920-7859 or (800) 608-7859.

Visit the TCPL website at: http://www.transcanada.com.