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TRANSCANADA PIPELINES LIMITED – THIRD QUARTER 2009

Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated November 3, 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 nine months ended September 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 securityholders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of TCPL's and its subsidiaries' 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 other things, 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 industry 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", "comparable earnings per common share", "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.

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, 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, non-controlling interests and preferred share dividends.

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. Comparable earnings per common share is calculated by dividing comparable earnings by the weighted average number of common shares outstanding for the period.

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 September 30 *(unaudited)(millions of dollars)*	Pipelines **2009**	Pipelines 2008	Energy **2009**	Energy 2008	Corporate **2009**	Corporate 2008	Total **2009**	Total 2008
Comparable EBITDA[1]	**730**	723	**292**	366	**(28)**	(23)	**994**	1,066
Depreciation and amortization	**(255)**	(254)	**(88)**	(64)	**-**	-	**(343)**	(318)
Comparable EBIT[1]	**475**	469	**204**	302	**(28)**	(23)	**651**	748
Specific item:								
Fair value adjustments of natural gas inventory and forward contracts	**-**	-	**14**	(2)	**-**	-	**14**	(2)
EBIT[1]	**475**	469	**218**	300	**(28)**	(23)	**665**	746
Interest expense							**(228)**	(217)
Financial charges of joint ventures							**(17)**	(18)
Interest income and other							**41**	16
Income taxes							**(101)**	(126)
Non-controlling interests and preferred share dividends							**(23)**	(18)
Net Income Applicable to Common Shares							**337**	383
Specific items (net of tax, where applicable):								
Fair value adjustments of natural gas inventory and forward contracts							**(10)**	2
Income tax reassessments and adjustments							**-**	(26)
Comparable Earnings[1]							**327**	359

(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 nine months ended September 30 (unaudited)(millions of dollars)	Pipelines 2009	Pipelines 2008	Energy 2009	Energy 2008	Corporate 2009	Corporate 2008	Total 2009	Total 2008
Comparable EBITDA[1]	**2,348**	2,239	**883**	913	**(89)**	(71)	**3,142**	3,081
Depreciation and amortization	**(773)**	(765)	**(261)**	(178)	**-**	-	**(1,034)**	(943)
Comparable EBIT[1]	**1,575**	1,474	**622**	735	**(89)**	(71)	**2,108**	2,138
Specific items:								
Fair value adjustments of natural gas inventory and forward contracts	**-**	-	**(6)**	(7)	**-**	-	**(6)**	(7)
Calpine bankruptcy settlements	**-**	279	**-**	-	**-**	-	**-**	279
GTN lawsuit settlement	**-**	17	**-**	-	**-**	-	**-**	17
Writedown of Broadwater LNG project costs	**-**	-	**-**	(41)	**-**	-	**-**	(41)
EBIT[1]	**1,575**	1,770	**616**	687	**(89)**	(71)	**2,102**	2,386
Interest expense							**(793)**	(632)
Financial charges of joint ventures							**(47)**	(51)
Interest income and other							**97**	47
Income taxes							**(310)**	(498)
Non-controlling interests and preferred share dividends							**(71)**	(106)
Net Income Applicable to Common Shares							**978**	1,146
Specific items (net of tax, where applicable):								
Fair value adjustments of natural gas inventory and forward contracts							**4**	6
Calpine bankruptcy settlements							**-**	(152)
GTN lawsuit settlement							**-**	(10)
Writedown of Broadwater LNG project costs							**-**	27
Income tax reassessments and adjustments							**-**	(26)
Comparable Earnings[1]							**982**	991

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

TCPL's net income applicable to common shares in third quarter 2009 was $337 million compared to $383 million in third quarter 2008. The $46 million decrease in net income applicable to common shares reflected:

- increased EBIT from Pipelines primarily due to increased earnings for the Alberta System as a result of a settlement approved in December 2008, the positive impact of a stronger U.S. dollar on Pipelines' U.S. operations and higher operations, maintenance and administrative (OM&A) cost savings for the Canadian Mainline;

- decreased EBIT from Energy primarily due to lower power prices in Western Power, and reduced volumes in Western Power, New England and Bruce Power. These decreases were partially offset by a $16 million year-over-year positive change in the pre-tax fair value adjustment of natural gas inventory and forward contracts, as well as increased earnings as a result of the acquisition of Ravenswood and the start up of Portlands Energy and the Carleton wind farm. Energy's EBIT also reflects higher contribution from the Natural Gas Storage business due to increased third party storage revenues;

- increased interest income and other 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; and

- decreased income tax expense primarily due to reduced earnings, higher income tax rate differentials and other positive income tax adjustments.

Comparable earnings in third quarter 2009 were $327 million compared to $359 million for the same period in 2008. Comparable earnings in third quarter 2009 and 2008 excluded $10 million of after tax ($14 million pre-tax) net unrealized gains and $2 million of after tax ($2 million pre-tax) net unrealized losses, respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Comparable earnings in 2008 also excluded $26 million of favourable income tax adjustments.

On a consolidated basis, the impact of changes in the U.S. dollar on U.S. Pipelines and Energy EBIT is largely offset by the impact on U.S. dollar interest expense and other income statement items. The resultant net exposure is managed using derivatives thereby effectively reducing the Company's exposure to changes in foreign exchange. The average U.S. dollar exchange rate for the three and nine months ended September 30, 2009 was 1.10 and 1.17, respectively (2008 - 1.04 and 1.02, respectively).

TCPL's net income applicable to common shares in the first nine months of 2009 was $978 million compared to $1.1 billion for the same period in 2008. The $168 million decrease in net income applicable to common shares reflected:

- decreased EBIT from Pipelines primarily 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 in 2009 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 reduced volumes in Western Power and New England. These decreases were partially offset by higher realized prices at Bruce Power, increased earnings from the start up of Portlands Energy and the Carleton wind farm, and the positive impact of a stronger U.S. dollar on Energy's U.S. operations. EBIT also reflects 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;

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

- 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 an increase in interest capitalized relating to Keystone and other capital projects;

- increased interest income and other 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;

- decreased income tax expense due to lower earnings and higher income tax rate differentials in 2009; and

- a reduction in non-controlling interests due to Portland's portion of the Calpine bankruptcy settlements recorded in 2008.

Comparable earnings in the first nine months of 2009 were $982 million compared to $991 million for the same period in 2008. Comparable earnings for the first nine months of 2009 and 2008 excluded $4 million after tax ($6 million pre-tax) and $6 million after tax ($7 million pre-tax), respectively, of net unrealized losses from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. In addition, comparable earnings in the first nine 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, the $27 million after tax writedown of Broadwater LNG project costs and $26 million of favourable income tax adjustments.

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

Pipelines

The Pipelines business generated comparable EBIT of $475 million and $1.6 billion in the three and nine month periods ended September 30, 2009, respectively, compared to $469 million and $1.5 billion for the same periods in 2008.

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

Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
Canadian Pipelines				
Canadian Mainline	**279**	268	**851**	841
Alberta System	**190**	182	**535**	540
Foothills	**32**	33	**100**	102
Other (TQM, Ventures LP)	**13**	13	**44**	39
Canadian Pipelines Comparable EBITDA(1)	**514**	496	**1,530**	1,522
U.S. Pipelines				
ANR	**57**	74	**263**	248
GTN(2)	**42**	48	**152**	146
Great Lakes	**31**	28	**108**	93
Iroquois	**18**	15	**62**	42
PipeLines LP(3)	**24**	13	**64**	47
Portland(4)	**2**	4	**18**	18
International (Tamazunchale, TransGas, INNERGY/Gas Pacifico)	**18**	10	**46**	32
General, administrative and support costs(5)	**(11)**	(4)	**(17)**	(14)
Non-controlling interests(6)	**45**	40	**148**	133
U.S. Pipelines Comparable EBITDA(1)	**226**	228	**844**	745
Business Development Comparable EBITDA(1)	**(10)**	(1)	**(26)**	(28)
Pipelines Comparable EBITDA(1)	**730**	723	**2,348**	2,239
Depreciation and amortization	**(255)**	(254)	**(773)**	(765)
Pipelines Comparable EBIT(1)	**475**	469	**1,575**	1,474
Specific items:				
Calpine bankruptcy settlements(7)	**-**	-	**-**	279
GTN lawsuit settlement	**-**	-	**-**	17
Pipelines EBIT(1)	**475**	469	**1,575**	1,770

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of comparable EBITDA, comparable EBIT and EBIT.
(2) GTN's results include North Baja to June 30, 2009.
(3) Effective July 1, 2009, TCPL's ownership interest in PipeLines LP increased to 42.6 per cent. As a result, PipeLines LP's results include TCPL's ownership of an additional 10.5 per cent of PipeLines LP and TCPL's effective ownership of 42.6 per cent of North Baja since July 1, 2009.
(4) Portland's results reflect TCPL's 61.7 per cent ownership interest.
(5) Represents certain costs associated with supporting the Company's Canadian and U.S. Pipelines.
(6) The non-controlling interests reflect PipeLines LP and Portland amounts not owned by TCPL.
(7) 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) *(millions of dollars)*	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Canadian Mainline	**68**	66	**201**	204
Alberta System	**44**	32	**123**	97
Foothills	**6**	6	**18**	19

Canadian Pipelines

Canadian Mainline's net income for the three and nine months ended September 30, 2009 increased $2 million and decreased $3 million, respectively, to $68 million and $201 million, respectively, compared to the same periods in 2008. Net income for third quarter 2009 reflected higher OM&A cost savings, partially offset by 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. Net income for the nine months ended September 30, 2009 decreased as higher OM&A cost savings were more than offset by the lower average investment base and ROE.

Canadian Mainline's EBITDA for the three and nine months ended September 30, 2009 of $279 million and $851 million, respectively, increased $11 million and $10 million, respectively, compared to the same periods in 2008, primarily due to higher revenues as a result of the recovery of higher depreciation and income taxes approved in the 2009 tolls, and higher OM&A cost savings. The increases in revenues were partially offset by a lower overall return on a reduced average investment base.

The Alberta System's net income was $44 million in third quarter 2009 and $123 million for the first nine months of 2009 compared to $32 million and $97 million for the same periods in 2008. Earnings in 2009 reflected the impact of a 2008-2009 settlement approved by the Alberta Utilities Commission (AUC) in December 2008 and the impact of a higher average investment base compared to 2008 due to customer-driven expansions of the Alberta System.

The Alberta System's EBITDA was $190 million in third quarter 2009 and $535 million for the first nine months of 2009 compared to $182 million and $540 million for the same periods in 2008. Third quarter EBITDA reflects increases due to higher settlement earnings and revenues as a result of the recovery of higher financial charges. For the nine months ended September 30, 2009, these increases were more than offset by reduced revenues as a result of the recovery of lower depreciation and income taxes approved in the settlement.

EBITDA from Other Canadian Pipelines was $13 million and $44 million for the three and nine months ended September 30, 2009, respectively, compared to $13 million and $39 million for the same periods in 2008. The increase in the nine month period was primarily due to the NEB decision on TQM's cost of capital for the years 2007 and 2008 reached in February 2009.

U.S. Pipelines

ANR's EBITDA for the three and nine months ended September 30, 2009 was $57 million and $263 million, respectively, compared to $74 million and $248 million, respectively, for the same periods in 2008. The decrease in EBITDA in third quarter 2009 was primarily due to reduced revenues as a result of lower utilization, lower incidental natural gas and condensate sales, and higher OM&A costs, partially offset by the positive impact of a stronger U.S. dollar. For the nine months ended September 30, 2009, the increase in EBITDA was primarily due to the positive impact of a stronger U.S. dollar and higher revenues, partially offset by lower natural gas and condensate sales, and higher OM&A costs.

GTN's EBITDA for the three months ended September 30, 2009 decreased $6 million from the same period in 2008 primarily due to the sale of North Baja to PipeLines LP on July 1, 2009. GTN's EBITDA for the nine months ended September 30, 2009 increased $6 million from the same period in 2008 primarily due to the positive impact of a stronger U.S. dollar, partially offset by the sale of North Baja in 2009.

EBITDA for the remainder of the U.S. Pipelines was $127 million and $429 million for the three and nine months ended September 30, 2009, respectively, compared to $106 million and $351 million for the same periods in 2008. The increases were primarily due to the positive impact of a stronger U.S. dollar in 2009, increased revenues for Gas Pacifico resulting from a new transportation agreement, TCPL's increased ownership in PipeLines LP and PipeLines LP's acquisition of North Baja, partially offset by charges incurred in restructuring the U.S. pipeline operations. The increase for the nine month period also included higher short-term revenues for Iroquois.

Operating Statistics

Nine months ended September 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)	**6,549**	7,065	**4,724**	4,322	**711**	755	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**1,561**	1,635	**2,652**	2,833	**901**	955	**1,199**	1,219	**578**	595
Average per day	**5.7**	6.0	**9.7**	10.3	**3.3**	3.5	**4.4**	4.5	**2.1**	2.2

(1) Canadian Mainline 2009 and 2008 delivery volumes reflect physical deliveries to domestic and export markets. Delivery volumes reported prior to third quarter 2009 reflected contract deliveries, however, customer contracting patterns have changed in recent years making physical deliveries a better measure of system utilization. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the nine months ended September 30, 2009 were 1,234 billion cubic feet (Bcf) (2008 – 1,460 Bcf); average per day was 4.5 Bcf (2008 – 5.3 Bcf).

(2) Field receipt volumes for the Alberta System for the nine months ended September 30, 2009 were 2,734 Bcf (2008 – 2,908 Bcf); average per day was 10.0 Bcf (2008 – 10.6 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 September 30, 2009, Other Assets included $212 million of capitalized costs related to the Keystone pipeline system expansion to the Gulf Coast.

As at September 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 $204 million in third quarter 2009 compared to $302 million in third quarter 2008. Comparable EBIT excluded net unrealized gains of $14 million and net unrealized losses of $2 million in third 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 $622 million for the first nine months of 2009 compared to $735 million in the same nine months of 2008. Comparable EBIT excluded net unrealized losses of $6 million and $7 million in the first nine months of 2009 and 2008, respectively, resulting from changes in the fair value of proprietary natural gas inventory and natural gas forward purchase and sale contracts. Comparable EBIT in 2008 also excluded the $41 million writedown of costs previously capitalized for the Broadwater LNG project.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Canadian Power				
Western Power	**66**	145	**218**	382
Eastern Power	**52**	35	**164**	104
Bruce Power	**81**	102	**282**	205
General, administrative and support costs	**(9)**	(12)	**(28)**	(28)
Canadian Power Comparable EBITDA[1]	**190**	270	**636**	663
U.S. Power[2]				
Northeast Power	**80**	85	**198**	209
General, administrative and support costs	**(12)**	(9)	**(35)**	(28)
U.S. Power Comparable EBITDA[1]	**68**	76	**163**	181
Natural Gas Storage				
Alberta Storage	**47**	35	**122**	114
General, administrative and support costs	**(2)**	(4)	**(7)**	(10)
Natural Gas Storage Comparable EBITDA[1]	**45**	31	**115**	104
Business Development Comparable EBITDA[1]	**(11)**	(11)	**(31)**	(35)
Energy Comparable EBITDA[1]	**292**	366	**883**	913
Depreciation and amortization	**(88)**	(64)	**(261)**	(178)
Energy Comparable EBIT[1]	**204**	302	**622**	735
Specific items:				
Fair value adjustments of natural gas inventory and forward contracts	**14**	(2)	**(6)**	(7)
Writedown of Broadwater LNG project costs	**-**	-	**-**	(41)
Energy EBIT[1]	**218**	300	**616**	687

(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 September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Revenues				
Western power	**196**	264	**585**	842
Eastern power	**69**	48	**209**	148
Other(3)	**32**	56	**122**	108
	297	368	**916**	1,098
Commodity Purchases Resold				
Western power	**(120)**	(114)	**(327)**	(380)
Eastern power	**-**	-	**-**	(2)
Other(4)	**(17)**	(13)	**(80)**	(47)
	(137)	(127)	**(407)**	(429)
Plant operating costs and other	**(42)**	(60)	**(129)**	(183)
General, administrative and support costs	**(9)**	(12)	**(28)**	(28)
Other (expense)/income	**-**	(1)	**2**	-
Comparable EBITDA(2)	**109**	168	**354**	458

(1) Includes Portlands Energy and the Carleton wind farm 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, sulphur 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 September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Sales Volumes (GWh)				
Supply				
Generation				
Western Power	**541**	598	**1,718**	1,733
Eastern Power	**305**	225	**1,081**	737
Purchased				
Sundance A & B and Sheerness PPAs	**2,560**	2,949	**7,725**	9,143
Other purchases	**113**	252	**420**	789
	3,519	4,024	**10,944**	12,402
Sales				
Contracted				
Western Power	**2,514**	2,686	**7,164**	8,579
Eastern Power	**307**	297	**1,117**	899
Spot				
Western Power	**698**	1,041	**2,663**	2,924
	3,519	4,024	**10,944**	12,402
Plant Availability				
Western Power(2)	**90%**	92%	**92%**	87%
Eastern Power	**97%**	98%	**97%**	97%

(1) Includes Portlands Energy and the Carleton wind farm effective April 2009 and November 2008, respectively.
(2) Excludes facilities that provide power to TCPL under PPAs.

Western Power's EBITDA of $66 million in third quarter 2009 decreased $79 million compared to $145 million in third quarter 2008. This decrease was primarily due to lower earnings from the Alberta power portfolio resulting from lower overall realized power prices on lower volumes of power sold. In addition, Western Power's EBITDA in third quarter 2008 included $17 million relating to sulphur sales.

Western Power's EBITDA of $218 million in the nine months ended September 30, 2009 decreased $164 million compared to $382 million for 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). Western Power's EBITDA for the nine months ended September 30, 2008 also included $17 million relating to sulphur sales.

Lower overall realized power prices as well as lower sales volumes resulted in decreases of $68 million and $257 million in Western Power's power revenues for the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008. Lower sales volumes were the result of reduced dispatch of the Alberta PPAs during periods of reduced demand.

Eastern Power's EBITDA of $52 million and $164 million for the three and nine months ended September 30, 2009, respectively, increased $17 million and $60 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 the Bécancour facility.

Eastern Power's power revenues increased $21 million and $61 million for the three and nine months ended September 30, 2009, respectively, primarily due to incremental revenues from Portlands Energy and the Carleton wind farm.

For the nine months ended September 30, 2009, Other Revenues and Other Commodity Purchases Resold of $122 million and $80 million, respectively, increased compared to the same period in 2008 as a result of an increase in the quantity of natural gas being resold in Eastern Power in first quarter 2009.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of $42 million and $129 million for the three and nine months ended September 30, 2009, respectively, decreased from the same periods in 2008 primarily due to lower prices for natural gas 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 78 per cent of Western Power sales volumes were sold under contract in third quarter 2009, compared to 72 per cent in third quarter 2008. To reduce its exposure to spot market prices on uncontracted volumes, as at September 30, 2009, Western Power had entered into fixed-price power sales contracts to sell approximately 3,200 gigawatt hours (GWh) for the remainder of 2009 and 9,200 GWh for 2010.

Eastern Power is focused on selling power under long-term contracts. As a result, in third 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 September 30 **2009**	 2008	Nine months ended September 30 **2009**	 2008
Revenues[1][2]	**224**	227	**685**	603
Operating Expenses[2]	**(143)**	(125)	**(403)**	(398)
Comparable EBITDA[3]	**81**	102	**282**	205
Bruce A Comparable EBITDA[3]	**(11)**	22	**77**	79
Bruce B Comparable EBITDA[3]	**92**	80	**205**	126
Comparable EBITDA[3]	**81**	102	**282**	205
Bruce Power – Other Information				
Plant availability				
Bruce A	**71%**	85%	**89%**	88%
Bruce B	**97%**	94%	**90%**	82%
Combined Bruce Power	**89%**	92%	**90%**	85%
Planned outage days				
Bruce A	**46**	12	**46**	45
Bruce B	**-**	-	**45**	100
Unplanned outage days				
Bruce A	**3**	8	**8**	10
Bruce B	**3**	12	**44**	60
Sales volumes (GWh)				
Bruce A	**1,099**	1,356	**4,157**	4,182
Bruce B	**1,950**	2,153	**5,751**	5,581
	3,049	3,509	**9,908**	9,763
Results per MWh				
Bruce A power revenues	**$64**	$63	**$64**	$62
Bruce B power revenues	**$66**	$59	**$64**	$57
Combined Bruce Power revenues	**$66**	$60	**$64**	$59
Percentage of Bruce B output sold to spot market	**49%**	33%	**42%**	37%

(1) Revenues include Bruce A's fuel cost recoveries of $7 million and $28 million for the three and nine months ended September 30, 2009, respectively (2008 - $5 million and $32 million, respectively). Revenues also include gains of $2 and $4 million as a result of changes in fair value of held-for-trading derivatives for the three and nine months ended September 30, 2009, respectively (2008 - gain of $5 million and loss of $1 million, respectively).

(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.

TCPL's proportionate share of Bruce Power's comparable EBITDA decreased $21 million to $81 million in third quarter 2009 compared to third quarter 2008 primarily due to higher operating costs as well as lower output as a result of increased outage days.

TCPL's proportionate share of Bruce A's comparable EBITDA decreased $33 million to a loss of $11 million in third quarter 2009 compared to earnings of $22 million in third quarter 2008 as a result of decreased volumes and higher operating costs due to an increase in outage days following the rescheduling of two planned outages from March 2009 to September 2009. Bruce A's availability in third quarter 2009 was 71 per cent as a result of 49 outage days compared to an availability of 85 per cent and 20 outage days in the same period in 2008.

TCPL's proportionate share of Bruce B's comparable EBITDA increased $12 million to $92 million in third quarter 2009 compared to third 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).

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 nine months of 2009 are expected to be repaid.

TCPL's proportionate share of Bruce Power's Comparable EBITDA increased $77 million to $282 million in the nine months ended September 30, 2009 compared to the same period in 2008 due to higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism as well as higher output, deemed generation payments in third quarter 2009 and lower operating costs per MWh due to fewer outage days.

TCPL's share of Bruce Power's generation in third quarter 2009 decreased to 3,049 GWh compared to 3,509 GWh in third quarter 2008, however, Bruce Power received deemed generation payments at OPA contract prices during periods of surplus baseload generation when the output of the units was reduced due to system curtailments required by the Independent Electricity System Operator. Including deemed generation, the Bruce Power units' combined average availability was 89 per cent in third quarter 2009, compared to 92 per cent in third quarter 2008. 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 third 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 third quarter 2008. All output from the Bruce B Units 5 to 8 were subject to a floor price of $48.76 per MWh in third quarter 2009 and $47.66 per MWh in third quarter 2008. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

At September 30, 2009, Bruce B had sold forward approximately 1,000 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 $66 per MWh and $64 per MWh in the three and nine months ended September 30, 2009, respectively, reflects revenues recognized from both the floor price mechanism and contract sales, compared to $59 per MWh and $57 per MWh in the same periods in 2008 in which no revenues were recognized under the floor price mechanism.

As at September 30, 2009, Bruce A had incurred approximately $3.1 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 September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Revenues				
Power	**374**	263	**1,035**	704
Other[3][4]	**114**	81	**364**	258
	488	344	**1,399**	962
Commodity Purchases Resold				
Power	**(147)**	(121)	**(419)**	(360)
Other[5]	**(84)**	(77)	**(271)**	(239)
	(231)	(198)	**(690)**	(599)
Plant operating costs and other[4]	**(177)**	(61)	**(511)**	(154)
General, administrative and support costs	**(12)**	(9)	**(35)**	(28)
Comparable EBITDA[2]	**68**	76	**163**	181

(1) Includes Ravenswood effective August 26, 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 September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Sales Volumes (GWh)				
Supply				
Generation	**2,021**	1,217	**4,593**	2,847
Purchased	**1,259**	1,566	**3,653**	4,383
	3,280	2,783	**8,246**	7,230
Sales				
Contracted	**2,800**	2,751	**7,265**	7,032
Spot	**480**	32	**981**	198
	3,280	2,783	**8,246**	7,230
Plant Availability[2]	**97%**	98%	**78%**	96%

(1) Includes Ravenswood effective August 26, 2008.
(2) Plant availability decreased in the nine months ended September 30, 2009 due to the impact of a forced outage affecting Unit 30 at Ravenswood, which returned to service May 17, 2009.

U.S. Power's EBITDA for the three and nine months ended September 30, 2009 of $68 million and $163 million, respectively, decreased $8 million and $18 million, respectively, compared to the same periods in 2008. These decreases were due to reduced power prices and lower volumes of power sold to commercial and industrial customers in New England as a result of unseasonably cool summer weather, which resulted in a decrease in demand, partially offset by incremental revenue realized on contract sales in New England. While average spot market power prices in New England decreased in 2009 compared to 2008, the majority of U.S. Power's sales in New England are sold at contracted prices. These decreases were also partially offset by incremental EBITDA from the Ravenswood facility which was acquired in August 2008 and the impact of a stronger U.S. dollar in the first nine months of 2009.

U.S. Power's power revenues for the three and nine months ended September 30, 2009 of $374 million and $1,035 million, respectively, increased from $263 million and $704 million for the same periods in 2008 due to incremental revenues from the Ravenswood facility, an increase in financial contract sales and the impact of a stronger U.S. dollar, partially offset by lower volumes of power sold in New England.

Other Revenues of $114 million and $364 million for the three and nine months ended September 30, 2009, respectively, increased $33 million and $106 million, respectively, compared to the same periods in 2008 due to incremental revenues earned from a steam generating facility at Ravenswood, as well as an increase in the volume of natural gas sold and the impact of a stronger U.S. dollar in 2009.

Power Commodity Purchases Resold of $147 million and $419 million for the three and nine months ended September 30, 2009, respectively, increased from $121 million and $360 million in the same periods in 2008 primarily due to the incremental impact of financial contract purchases in New England and the impact of a stronger U.S. dollar in 2009. These increases were partially offset by lower volumes of power purchased for resale to commercial and industrial customers in New England.

Other Commodity Purchases Resold for the three and nine months ended September 30, 2009 of $84 million and $271 million, respectively, increased from $77 million and $239 million for the same periods in 2008 primarily due to higher volumes of natural gas purchased and resold as well as the impact of a stronger U.S. dollar, partially offset by a decrease in natural gas prices.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of $177 million and $511 million for the three and nine months ended September 30, 2009, respectively, increased $116 million and $357 million, respectively, from the same periods in 2008 due to incremental costs from the Ravenswood facility.

In the three and nine months ended September 30, 2009, 15 per cent and 12 per cent, respectively, of power sales volumes were sold into the spot market, compared to one and three 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 September 30, 2009, U.S. Power had entered into fixed-price power sales contracts to sell approximately 2,500 GWh for the remainder of 2009 and 7,600 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 nine months ended September 30, 2009 was $45 million and $115 million, respectively, compared to $31 million and $104 million for the same periods in 2008. The $14 million and $11 million increases in EBITDA in third quarter 2009 and nine months ended September 30, 2009 were primarily due to increased third party storage revenues.

Comparable EBITDA excluded net unrealized gains of $14 million and net unrealized losses of $6 million in the three and nine months ended September 30, 2009, respectively (2008 – losses of $2 million and $7 million, respectively), 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. The fair value of proprietary natural gas inventory held in storage has been measured using a weighted average of forward prices for the following four months less selling costs.

Depreciation and Amortization

Depreciation and Amortization for the three and nine months ended September 30, 2009 of $88 million and $261 million, respectively, increased $24 million and $83 million, respectively, compared to the same periods in 2008, primarily due to the acquisition of Ravenswood in August 2008.

Corporate

Corporate EBIT losses for the three and nine months ended September 30, 2009 were $28 million and $89 million, respectively, compared to losses of $23 million and $71 million for the same periods in 2008. These increases in EBIT losses 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 September 30		Nine months ended September 30	
(million of dollars)	**2009**	2008	**2009**	2008
Interest on long-term debt[1]	**317**	257	**982**	739
Other interest and amortization	**24**	(2)	**41**	(10)
Capitalized interest	**(113)**	(38)	**(230)**	(97)
	228	217	**793**	632

(1) Includes interest for Junior Subordinated Notes.

Interest Expense for third quarter 2009 increased $11 million to $228 million from $217 million in third quarter 2008. Interest Expense for the nine months ended September 30, 2009, increased $161 million to $793 million from $632 million for the nine months ended September 30, 2008. These increases reflected 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, as well as higher losses from changes in the fair value of derivatives used to manage the Company's exposure to interest rate fluctuations. 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 primarily due to the construction of Keystone and the acquisition of the remaining 20 per cent ownership interest in Keystone from ConocoPhillips.

Interest Income and Other was $41 million and $97 million for the three and nine month periods ended September 30, 2009, respectively, compared to $16 million and $47 million for the same periods in 2008. The increase of $25 million and $50 million for the three and nine months ended September 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. An increase in interest income due to higher cash balances held in 2009 was more than offset by lower interest rates.

Income Taxes were $101 million in third quarter 2009 compared to $126 million for the same period in 2008. Income Taxes for the nine months ended September 30, 2009 were $310 million compared to $498 million for the same period in 2008. The decreases were primarily due to reduced earnings and higher income tax rate differentials and other positive income tax adjustments in 2009.

Non-Controlling Interests were $17 million for third quarter 2009 compared to $12 million for the same period in 2008. The increase of $5 million was primarily due to higher earnings in PipeLines LP, partially offset by lower earnings in Portland. Non-Controlling Interests of $54 million for the first nine months of 2009, decreased $35 million compared to $89 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, partially offset by higher PipeLines LP earnings in 2009.

Liquidity and Capital Resources

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, and 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 common 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 $150 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 September 30, 2009, the Company held cash and cash equivalents of $2.4 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 in 2009 of common shares and long-term debt.

Operating Activities

Funds Generated from Operations(1)

(unaudited) *(millions of dollars)*	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Cash Flows				
Funds generated from operations(1)	**759**	702	**2,205**	2,287
(Increase)/decrease in operating working capital	**(30)**	128	**366**	24
Net cash provided by operations	**729**	830	**2,571**	2,311

(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 decreased $101 million and increased $260 million for the three and nine months ended September 30, 2009, respectively, compared to the same periods in 2008, primarily due to changes in operating working capital. Funds Generated from Operations (FGFO) for the three and nine months ended September 30, 2009, $759 million and $2.2 billion, respectively, compared to $702 million and $2.3 billion for the same periods in 2008. FGFO for the three months ended September 30, 2009 increased primarily due to increased cash from earnings, partially offset by increased pension contributions in 2009. FGFO for the nine months ended September 30, 2009 decreased primarily due to $152 million of after tax proceeds received in 2008 from the Calpine bankruptcy settlements and increased pension contributions in 2009, partially offset by increased cash from earnings.

Investing Activities

Acquisitions, net of cash acquired, were $653 million in third quarter 2009 (2008 - $3.1 billion) and $902 million (2008 - $3.1 billion) for the nine months ended September 30, 2009. In August 2009, the Company acquired ConocoPhillips' remaining 20 per cent interest in Keystone. Acquisitions for the nine months ended September 30, 2009 also included the previous increases in ownership interest in Keystone pursuant to an agreement with ConocoPhillips that became effective December 2008.

TCPL remains committed to executing its previously announced $22 billion capital expenditure program over the next four years. For the three and nine months ended September 30, 2009, capital expenditures totalled $1.6 billion and $3.9 billion, respectively (2008 - $0.8 billion and $1.9 billion, respectively), primarily related to construction of 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

In the three and nine months ended September 30, 2009, TCPL issued 47.6 million and 51.5 million common shares, respectively (2008 – 32.7 million and 36.1 million common shares, respectively), to TransCanada Corporation (TransCanada) for proceeds of $1.6 billion and $1.7 billion, respectively (2008 - $1.3 billion and $1.4 billion, respectively). The proceeds of these issues are expected to be used to partially fund capital projects, for general corporate purposes and to repay short-term indebtedness of TCPL and its affiliates.

The Company is well positioned to fund its existing capital program through its growing internally-generated cash flow and its continued access to capital markets. As demonstrated by the recent sale of North Baja to PipeLines LP, 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 nine months ended September 30, 2009, TCPL issued $207 million and $3.3 billion, respectively (2008 - $2.1 billion and $2.2 billion, respectively), and retired $9 million and $509 million, respectively (2008 - $15 million and $788 million, respectively), of long-term debt. TCPL's notes payable increased $77 million and decreased $607 million in the three and nine months ended September 30, 2009, respectively, compared to a decrease of $258 million and an increase of $832 million for the same periods in 2008.

In April 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 has remaining capacity of US$1.0 billion.

On October 20, 2009, the Company retired $250 million of 10.625 per cent debentures.

Dividends

On November 3, 2009, TCPL's Board of Directors declared a dividend for the quarter ending December 31, 2009 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada Corporation's (TransCanada) issued and outstanding common shares at the close of business on December 31, 2009. The Board also declared regular dividends on TCPL's preferred shares.

TransCanada's Board of Directors approved the issuance of common shares from treasury at a three per cent discount under TransCanada's Dividend Reinvestment and Share Purchase Plan for the dividends payable on January 29, 2010. Under this plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common 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 Regulatory 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 Regulatory Assets. 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 CICA 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 Steering Committee. 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 will 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 August 14, 2009, the Company acquired ConocoPhillips' remaining interest in Keystone. As a result, TCPL assumed 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 September 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 September 30, 2009, there were no significant amounts past due or impaired.

As a level of uncertainty in the global financial markets remains, 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 September 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 $73 million (December 31, 2008 - $76 million).

The change in fair value of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2009 resulted in a net pre-tax unrealized gain of $16 million and a net pre-tax unrealized loss of $13 million, respectively (2008 – unrealized losses of $108 million and $6 million, respectively), which were recorded to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sales contracts in the three and nine months ended September 30, 2009 resulted in a net pre-tax unrealized loss of $2 million and a net pre-tax unrealized gain of $7 million, respectively (2008 - unrealized gain of $106 million and unrealized loss of $1 million), 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 September 30, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $8.1 billion (US$7.6 billion) and a fair value of $9.2 billion (US$8.6 billion). At September 30, 2009, Other Assets included $51 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)*	**September 30, 2009** **Fair Value**[1]	 **Notional or Principal Amount**	December 31, 2008 Fair Value[1]	 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2009 to 2014)[2]	**40**	**U.S. 1,650**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2009 to 2010)[2]	**7**	**U.S. 635**	(42)	U.S. 2,152
U.S. dollar options (maturing 2009)[2]	**4**	**U.S. 400**	6	U.S. 300
	51	**U.S. 2,685**	(254)	U.S. 4,102

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

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**September 30, 2009** Carrying Amount	Fair Value	December 31, 2008 Carrying Amount	Fair Value
Financial Assets[(1)]				
Cash and cash equivalents	**2,385**	**2,385**	1,300	1,300
Accounts receivable and other assets[(2)(3)]	**983**	**983**	1,404	1,404
Due from TransCanada Corporation	**1,631**	**1,631**	1,529	1,529
Available-for-sale assets[(2)]	**23**	**23**	27	27
	5,022	**5,022**	4,260	4,260
Financial Liabilities[(1)(3)]				
Notes payable	**1,324**	**1,324**	1,702	1,702
Accounts payable and deferred amounts[(4)]	**1,590**	**1,590**	1,364	1,364
Due to TransCanada Corporation	**2,757**	**2,757**	1,821	1,821
Accrued interest	**349**	**349**	361	361
Long-term debt and junior subordinated notes	**18,469**	**21,388**	17,367	16,152
Long-term debt of joint ventures	**1,090**	**1,149**	1,076	1,052
	25,579	**28,557**	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 September 30, 2009, the Consolidated Balance Sheet included financial assets of $834 million (December 31, 2008 – $1,257 million) in Accounts Receivable and $172 million (December 31, 2008 - $174 million) in Other Assets.

(3) Recorded at amortized cost.

(4) At September 30, 2009, the Consolidated Balance Sheet included financial liabilities of $1,588 million (December 31, 2008 – $1,342 million) in Accounts Payable and $2 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:

September 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	**$126**	**$129**	**$4**	**$4**	**$35**
Liabilities	**$(71)**	**$(134)**	**$(3)**	**$(64)**	**$(81)**
Notional Values					
Volumes[3]					
Purchases	**9,876**	**204**	**180**	-	-
Sales	**9,718**	**171**	**228**	-	-
Canadian dollars	-	-	-	-	**699**
U.S. dollars	-	-	-	**U.S. 426**	**U.S. 1,425**
Cross-currency	-	-	-	**227/U.S. 157**	-
Net unrealized (losses)/gains in the period[4]					
Three months ended September 30, 2009	**$(8)**	**$21**	**$(1)**	**$2**	**$(7)**
Nine months ended September 30, 2009	**$11**	**$(4)**	**$1**	**$4**	**$20**
Net realized gains/(losses) in the period[4]					
Three months ended September 30, 2009	**$23**	**$(43)**	**$1**	**$11**	**$(5)**
Nine months ended September 30, 2009	**$53**	**$(56)**	-	**$28**	**$(14)**
Maturity dates	**2009-2014**	**2009-2014**	**2009-2010**	**2009-2012**	**2009-2018**
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[2]					
Assets	**$229**	**$2**	-	-	**$6**
Liabilities	**$(154)**	**$(15)**	-	**$(36)**	**$(67)**
Notional Values					
Volumes[3]					
Purchases	**13,597**	**24**	-	-	-
Sales	**14,806**	-	-	-	-
U.S. dollars	-	-	-	-	**U.S. 1,825**
Cross-currency	-	-	-	**136/U.S. 100**	-
Net realized gains/(losses) in the period[4]					
Three months ended September 30, 2009	**$30**	**$(8)**	-	-	**$(10)**
Nine months ended September 30, 2009	**$108**	**$(28)**	-	-	**$(27)**
Maturity dates	**2009-2015**	**2009-2012**	**n/a**	**2009- 2013**	**2010-2020**

(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 $6 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2009 were $1 million and $3 million, respectively, and were included in Interest Expense. In third 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 nine months ended September 30, 2009 included gains of $1 million and $2 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 nine months ended September 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 gains/(losses) in the period(3)					
Three months ended September 30, 2008	$5	$(1)	-	-	$5
Nine months ended September 30, 2008	-	$(12)	-	$(7)	$3
Net realized gains/(losses) in the period(3)					
Three months ended September 30, 2008	$12	$(11)	-	$2	$2
Nine months ended September 30, 2008	$21	$(6)	-	$12	$12
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 gains/(losses) in the period(3)					
Three months ended September 30, 2008	$14	$(1)	-	-	$(2)
Nine months ended September 30, 2008	$(24)	$18	-	-	$(4)
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. Net realized gains on fair value hedges for the three and nine months ended September 30, 2008 were $1 million and $1 million, respectively, and were included in Interest Expense. In third 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 nine months ended September 30, 2008 included gains of $7 million and $4 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 nine months ended September 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)*	**September 30, 2009**	December 31, 2008
Current		
Other current assets	**370**	318
Accounts payable	**(359)**	(298)
Long-term		
Other assets	**216**	191
Deferred amounts	**(266)**	(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 September 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 September 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

TCPL does not expect the slowdown in the North American economy 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 issued $1.6 billion of common shares in third quarter 2009, $3.1 billion of long-term debt in first quarter 2009 and $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 $2.6 billion of cash provided by operations in the first nine months of 2009, they have contributed to a cash balance of $2.4 billion at September 30, 2009 and provided 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 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.

TransCanada'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 (S&P).

Recent Developments

Pipelines

Keystone

On August 14, 2009, TCPL purchased ConocoPhillips' remaining 20 per cent ownership interest in Keystone for US$553 million plus the assumption of US$197 million of short-term indebtedness. Following this acquisition TCPL owns 100 per cent of Keystone and began consolidating Keystone into the Pipelines segment.

The first phase of Keystone is currently under construction, extending from Hardisty, Alberta to serve markets in Wood River and Patoka, Illinois with an initial nominal capacity of 435,000 barrels per day (bbl/d). Commissioning of this segment commenced in third quarter 2009 with commercial operations to follow in first quarter 2010. At September 30, 2009, the first phase was approximately 90 per cent complete. The second phase of Keystone will expand nominal capacity to 591,000 bbl/d and extend the pipeline to Cushing, Oklahoma. Commissioning of the Cushing segment is expected to commence in late 2010. At September 30, 2009, this phase of the project was approximately 20 per cent complete.

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 system that will provide additional capacity of 500,000 bbl/d from Western Canada to the Gulf Coast in 2012. In September 2009, the NEB held a hearing to review the application for the Canadian portion of the Keystone Gulf Coast expansion with a decision expected in early 2010. Permits for the U.S. portion of the expansion are expected by mid-2010. Construction of the expansion facilities is anticipated to commence in 2010 following the receipt of all the necessary regulatory approvals.

The total capital cost of Keystone is expected to be approximately US$12 billion. Approximately US$5 billion has been spent to date with the remaining US$7 billion to be invested between now and 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 were to 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 could be economically expanded from 1.1 million bbl/d to 1.5 million bbl/d in response to additional market demand.

Alberta System

On October 30, 2009, following discussions with stakeholders to migrate the 2008-2009 Revenue Requirement Settlement to NEB jurisdiction, TCPL submitted an application to the NEB requesting that 2009 interim rates be made final.

In September 2009, the Company began construction on the final phase of the North Central Corridor expansion, which is expected to be complete in April 2010. The capital cost of this phase of the project is estimated to be approximately $400 million.

Ventures LP

In September 2009, the Alberta Court of Appeal granted Ventures LP leave to appeal the AUC Decision 2009-065 where the AUC announced that it would seek an Order in Council allowing it to establish a process for regulating rates on the Ventures LP pipeline. The appeal is expected to be heard during first quarter 2010.

Review of NEB ROE Formula

In July 2009, the NEB initiated a review of the RH-2-94 Decision by seeking comments on the continuing applicability of that decision. The RH-2-94 Decision pursuant to the *National Energy Board Act* (Canada) established an ROE formula tied to Government of Canada bond yields that has formed the basis of determining tolls for pipelines under NEB jurisdiction since January 1, 1995. In October 2009, the NEB issued a decision that the RH-2-94 Decision would not continue to be in effect. The NEB stated that instead of a multi-pipeline approach, the cost of capital will be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. This decision impacts all of TCPL's NEB regulated pipelines, which include the Canadian Mainline, Alberta System and Foothills. The Canadian Mainline is expected to continue to base its return on the result of the RH-2-94 NEB ROE formula for the years 2010 and 2011 in accordance with the terms of the current Canadian Mainline tolls settlement. TCPL will be working with customers and interested parties to determine the cost of capital to be used in calculating tolls for 2010 on its other NEB regulated pipelines. If agreements cannot be reached, TCPL will file applications with the NEB requesting an appropriate cost of capital component.

Energy

Bruce Power

Progress continues on the refurbishment and restart of Bruce A Units 1 and 2 with work now advanced to the re-assembly of the reactors. As at September 30, 2009, Bruce A had incurred approximately $3.1 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. TCPL believes that the work on Units 1 and 2 is now approximately 75 per cent complete, with the bulk of the highly technical, high risk work now finished. Although a significant amount of work remains to be done, most of this work is conventional power plant construction activity.

The project has experienced delays and TCPL now expects that Unit 2 will be restarted mid-2011, with Unit 1 expected to follow approximately four months thereafter. The impact of this delay is mitigated by the previously announced extension of the operating lives of Unit 3 to 2011 and Unit 4 to 2016, with further life extensions expected as additional reactor optimization activities proceed. TCPL continues to work closely with Bruce Power to address productivity and overall project management and notes that there have been recent, significant successes in this area.

Oakville

On September 30, 2009, the OPA awarded TCPL a 20-year Clean Energy Supply contract to build, own and operate the 900 MW Oakville generating station in Oakville, Ontario. TCPL expects to invest approximately $1.2 billion in the natural gas-fired, combined-cycle plant which is scheduled to start producing power by the end of 2013. TCPL expects this project will deliver an after-tax unlevered rate of return of nine per cent.

Kibby Wind

In September 2009, the first phase of the Kibby Wind power project, capable of producing 66 MW of power, entered the commissioning phase. The 22 turbines included in this first phase were placed in service on October 30, 2009 on time and on budget. Construction continues on the 66 MW second phase of the project, which includes the installation of an additional 22 turbines. This phase is expected to be in service in third quarter 2010.

Coolidge

In August, 2009, TCPL began construction of the US$500 million Coolidge generating station located near Phoenix, Arizona. The 575 MW, simple-cycle, natural gas-fired peaking power facility is expected to be in service in second quarter 2011 on time and on budget. All of the power produced by the facility will be sold to the Phoenix, Arizona based utility Salt River Project under a 20-year PPA.

Cartier Wind

In third quarter 2009, construction activity began on the 212 MW Gros-Morne and 58.5 MW Montagne-Sèche wind farms. The Montagne-Sèche project and phase one of the Gros-Morne project (101 MW) are expected to be operational in 2011. Phase two of the Gros-Morne project (111 MW) is expected to be operational in 2012. These are the fourth and fifth Québec-based wind farms either operating or under development by Cartier Wind, which is 62 per cent owned by TCPL. These two wind farms are expected to have a capital cost of approximately $340 million. Once these two phases are complete, Cartier Wind will be capable of producing 590 MW of electricity. All of the power produced by Cartier Wind is sold to Hydro- Québec Distribution under a 20-year PPA.

Power Transmission Line Projects

On October 13, 2009, TCPL commenced open seasons on its proposed Zephyr and Chinook power transmission line projects. The open seasons are scheduled to end in fourth quarter 2009. Pending successful completion of the open seasons, regulatory work could commence in fourth quarter 2009, with construction commencing in 2012 and a potential in-service date of late 2014. Each project would cost approximately US$3 billion and be capable of delivering 3,000 MW of power originating in Wyoming and Montana, respectively, to Nevada.

Share Information

As at September 30, 2009, TCPL had 649 million issued and outstanding common shares.

Selected Quarterly Consolidated Financial Data[1]

(unaudited) *(millions of dollars except per share amounts)*	**2009**			2008				2007
	Third	**Second**	**First**	Fourth	Third	Second	First	Fourth
Revenues	**2,253**	**2,127**	**2,380**	2,332	2,137	2,017	2,133	2,189
Net Income Applicable to Common Shares	**337**	**311**	**330**	274	383	318	445	373
Share Statistics								
Net Income Applicable to Common Shares per common share – Basic and Diluted	**$0.55**	**$0.52**	**$0.55**	$0.47	$0.70	$0.60	$0.84	$0.71

(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, capacity payments, 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:

- Third quarter 2009, Energy's EBIT included net unrealized gains of $14 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.

- 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 did 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. 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 increased due to a $16 million pre-tax ($14 million after tax) gain on sale of land previously held for development. 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.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Revenues	**2,253**	2,137	**6,760**	6,287
Operating and Other Expenses/(Income)				
Plant operating costs and other	**879**	750	**2,544**	2,181
Commodity purchases resold	**371**	324	**1,100**	1,053
Other income	**(5)**	(1)	**(20)**	(38)
Calpine bankruptcy settlements	**-**	-	**-**	(279)
Writedown of Broadwater LNG project costs	**-**	-	**-**	41
	1,245	1,073	**3,624**	2,958
	1,008	1,064	**3,136**	3,329
Depreciation and amortization	**343**	318	**1,034**	943
	665	746	**2,102**	2,386
Financial Charges/(Income)				
Interest expense	**228**	217	**793**	632
Financial charges of joint ventures	**17**	18	**47**	51
Interest income and other	**(41)**	(16)	**(97)**	(47)
	204	219	**743**	636
Income before Income Taxes and Non-Controlling Interests	**461**	527	**1,359**	1,750
Income Taxes				
Current	**23**	126	**114**	475
Future	**78**	-	**196**	23
	101	126	**310**	498
Non-Controlling Interests				
Non-controlling interest in PipeLines LP	**19**	12	**51**	46
Non-controlling interest in Portland	**(2)**	-	**3**	43
	17	12	**54**	89
Net Income	**343**	389	**995**	1,163
Preferred Share Dividends	**6**	6	17	17
Net Income Applicable to Common Shares	**337**	383	**978**	1,146

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited)(millions of dollars)	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Cash Generated From Operations				
Net income	**343**	389	**995**	1,163
Depreciation and amortization	**343**	318	**1,034**	943
Future income taxes	**89**	-	**207**	23
Non-controlling interests	**17**	12	**54**	89
Employee future benefits funding (in excess of)/ lower than expense	**(22)**	10	**(79)**	23
Writedown of Broadwater LNG project costs	**-**	-	**-**	41
Other	**(11)**	(27)	**(6)**	5
	759	702	**2,205**	2,287
(Increase)/decrease in operating working capital	**(30)**	128	**366**	24
Net cash provided by operations	**729**	830	**2,571**	2,311
Investing Activities				
Capital expenditures	**(1,557)**	(806)	**(3,943)**	(1,899)
Acquisitions, net of cash acquired	**(653)**	(3,054)	**(902)**	(3,058)
Disposition of assets, net of current income taxes	**-**	21	**-**	21
Deferred amounts and other	**(181)**	60	**(505)**	171
Net cash used in investing activities	**(2,391)**	(3,779)	**(5,350)**	(4,765)
Financing Activities				
Dividends on common and preferred shares	**(266)**	(214)	**(734)**	(604)
Advances (to)/from parent	**(223)**	(14)	**834**	(380)
Distributions paid to non-controlling interests	**(19)**	(18)	**(59)**	(93)
Notes payable issued/(repaid), net	**77**	(258)	**(607)**	832
Long-term debt issued, net of issue costs	**207**	2,085	**3,267**	2,197
Reduction of long-term debt	**(9)**	(15)	**(509)**	(788)
Long-term debt of joint ventures issued	**93**	123	**201**	157
Reduction of long-term debt of joint ventures	**(52)**	(44)	**(108)**	(101)
Common shares issued	**1,550**	1,309	**1,676**	1,434
Net cash provided by financing activities	**1,358**	2,954	**3,961**	2,654
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(63)**	19	**(97)**	39
(Decrease)/Increase in Cash and Cash Equivalents	**(367)**	24	**1,085**	239
Cash and Cash Equivalents				
Beginning of period	**2,752**	719	**1,300**	504
Cash and Cash Equivalents				
End of period	**2,385**	743	**2,385**	743
Supplementary Cash Flow Information				
Income taxes (refunded)/paid	**(63)**	105	**50**	414
Interest paid	**297**	177	**834**	656

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited)(millions of dollars)	**September 30, 2009**	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	**2,385**	1,300
Accounts receivable	**834**	1,280
Due from TransCanada Corporation	**1,631**	1,529
Inventories	**491**	489
Other	**505**	523
	5,846	5,121
Plant, Property and Equipment	**32,289**	29,189
Goodwill	**3,855**	4,397
Regulatory Assets	**1,644**	201
Other Assets	**2,132**	2,027
	45,766	40,935
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**1,324**	1,702
Accounts payable	**2,343**	1,868
Due to TransCanada Corporation	**2,757**	1,821
Accrued interest	**349**	361
Current portion of long-term debt	**678**	786
Current portion of long-term debt of joint ventures	**235**	207
	7,686	6,745
Regulatory Liabilities	**430**	551
Deferred Amounts	**723**	1,168
Future Income Taxes	**2,825**	1,253
Long-Term Debt	**16,730**	15,368
Long-Term Debt of Joint Ventures	**855**	869
Junior Subordinated Notes	**1,061**	1,213
	30,310	27,167
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**561**	721
Non-controlling interest in Portland	**77**	84
	638	805
Shareholders' Equity	**14,818**	12,963
	45,766	40,935

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited)(millions of dollars)	Three months ended September 30 2009	Three months ended September 30 2008	Nine months ended September 30 2009	Nine months ended September 30 2008
Net Income	**343**	389	**995**	1,163
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(230)**	107	**(381)**	146
Change in gains and losses on hedges of investments in foreign operations(2)	**113**	(79)	**209**	(103)
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**16**	7	**80**	40
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	**(1)**	(6)	**(6)**	(24)
Other Comprehensive (Loss)/Income	**(102)**	29	**(98)**	59
Comprehensive Income	**241**	418	**897**	1,222

(1) Net of income tax expense of $68 million and $68 million for the three and nine months ended September 30, 2009, respectively (2008 – recovery of $23 million and $43 million, respectively).

(2) Net of income tax expense of $50 million and $102 million for the three and nine months ended September 30, 2009, respectively (2008 – recovery of $36 million and $50 million, respectively).

(3) Net of income tax expense of $4 million and $20 million for the three and nine months ended September 30, 2009, respectively (2008 – $25 million recovery and $24 million expense, respectively).

(4) Net of income tax expense of $4 million and $4 million for the three and nine months ended September 30, 2009, respectively (2008 – recovery of $9 million and $20 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)	**(381)**	**-**	**(381)**
Change in gains and losses on hedges of investments in foreign operations(2)	**209**	**-**	**209**
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**-**	**80**	**80**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)(5)	**-**	**(6)**	**(6)**
Balance at September 30, 2009	**(551)**	**(19)**	**(570)**

Balance at December 31, 2007	(361)	(12)	(373)
Change in foreign currency translation gains and losses on investments in foreign operations(1)	146	-	146
Change in gains and losses on hedges of investments in foreign operations(2)	(103)	-	(103)
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	-	40	40
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	-	(24)	(24)
Balance at September 30, 2008	(318)	4	(314)

(1) Net of income tax expense of $68 million for the nine months ended September 30, 2009 (2008 - $43 million recovery).
(2) Net of income tax expense of $102 million for the nine months ended September 30, 2009 (2008 - $50 million recovery).
(3) Net of income tax expense of $20 million for the nine months ended September 30, 2009 (2008 - $24 million expense).
(4) Net of income tax expense of $4 million for the nine months ended September 30, 2009 (2008 - $20 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 $30 million ($25 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)	Nine months ended September 30 **2009**	2008
Preferred Shares	**389**	389
Common Shares		
Balance at beginning of period	**8,973**	6,554
Proceeds from common shares issued	**1,676**	1,434
Balance at end of period	**10,649**	7,988
Contributed Surplus		
Balance at beginning of period	**284**	281
Increased ownership in PipeLines LP (Note 8)	**49**	-
Issuance of stock options	**4**	3
Balance at end of period	**337**	284
Retained Earnings		
Balance at beginning of period	**3,789**	3,202
Net income	**995**	1,163
Preferred share dividends	**(17)**	(17)
Common share dividends	**(754)**	(612)
Balance at end of period	**4,013**	3,736
Accumulated Other Comprehensive Income		
Balance at beginning of period	**(472)**	(373)
Other comprehensive income	**(98)**	59
Balance at end of period	**(570)**	(314)
Total Shareholders' Equity	**14,818**	12,083

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, capacity payments, 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 Regulatory 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 Regulatory Assets. 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 CICA 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 $14 million and $43 million in the three and nine months ended September 30, 2009, respectively (2008 - $14 million and $43 million, respectively), for power purchase arrangements, which was previously included in Commodity Purchases Resold. Support services costs previously allocated to Pipelines and Energy of $25 million and $87 million in the three and nine months ended September 30, 2009, respectively (2008 - $24 million and $75 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 are no longer reported on a segmented basis. Segmented information has been retroactively reclassified to reflect these changes. These changes had no impact on reported consolidated Net Income Applicable to Common Shares.

Three months ended September 30	Pipelines		Energy		Corporate		Total	
(unaudited)(millions of dollars)	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues	**1,152**	1,141	**1,101**	996	**-**	-	**2,253**	2,137
Plant operating costs and other	**(427)**	(421)	**(424)**	(306)	**(28)**	(23)	**(879)**	(750)
Commodity purchases resold	**-**	-	**(371)**	(324)	**-**	-	**(371)**	(324)
Other income/(expense)	**5**	3	**-**	(2)	**-**	-	**5**	1
	730	723	**306**	364	**(28)**	(23)	**1,008**	1,064
Depreciation and amortization	**(255)**	(254)	**(88)**	(64)	**-**	-	**(343)**	(318)
	475	469	**218**	300	**(28)**	(23)	**665**	746
Interest expense							**(228)**	(217)
Financial charges of joint ventures							**(17)**	(18)
Interest income and other							**41**	16
Income taxes							**(101)**	(126)
Non-controlling interests and preferred share dividends							**(23)**	(18)
Net Income Applicable to Common Shares							**337**	383

Nine months ended September 30 *(unaudited)(millions of dollars)*	Pipelines **2009**	 2008	Energy **2009**	 2008	Corporate **2009**	 2008	Total **2009**	 2008
Revenues	**3,558**	3,417	**3,202**	2,870	**-**	-	**6,760**	6,287
Plant operating costs and other	**(1,227)**	(1,194)	**(1,227)**	(910)	**(90)**	(77)	**(2,544)**	(2,181)
Commodity purchases resold	**-**	-	**(1,100)**	(1,053)	**-**	-	**(1,100)**	(1,053)
Other income/(expense)	**17**	33	**2**	(1)	**1**	6	**20**	38
Calpine bankruptcy settlements	**-**	279	**-**	-	**-**	-	**-**	279
Writedown of Broadwater LNG project costs	**-**	-	**-**	(41)	**-**	-	**-**	(41)
	2,348	2,535	**877**	865	**(89)**	(71)	**3,136**	3,329
Depreciation and amortization	**(773)**	(765)	**(261)**	(178)	**-**	-	**(1,034)**	(943)
	1,575	1,770	**616**	687	**(89)**	(71)	**2,102**	2,386
Interest expense							**(793)**	(632)
Financial charges of joint ventures							**(47)**	(51)
Interest income and other							**97**	47
Income taxes							**(310)**	(498)
Non-controlling interests and preferred share dividends							**(71)**	(106)
Net Income Applicable to Common Shares							**978**	1,146

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	 2007	Energy 2008	 2007	Corporate 2008	 2007	Total 2008	 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)	**September 30, 2009**	December 31, 2008
Pipelines	**28,895**	25,020
Energy	**12,078**	12,006
Corporate	**4,793**	3,909
	45,766	40,935

4. Long-Term Debt

On October 20, 2009, the Company retired $250 million of 10.625 per cent debentures.

In April 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 has remaining capacity of US$1.0 billion.

In the three and nine months ended September 30, 2009, the Company capitalized interest related to capital projects of $113 million and $230 million, respectively (2008 - $38 million and $97 million, respectively).

5. Share Capital

In the three and nine months ended September 30, 2009, TCPL issued 47.6 million and 51.5 million common shares, respectively (2008 – 32.7 million and 36.1 million common shares, respectively), to TransCanada Corporation (TransCanada) for proceeds of $1.6 billion and $1.7 billion, respectively (2008 - $1.3 billion and $1.4 billion, 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 September 30, 2009, there were no significant amounts past due or impaired.

As a level of uncertainty in the global financial markets remains, 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. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TCPL's consolidated VaR was $14 million at September 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 September 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 $73 million (December 31, 2008 - $76 million).

The change in fair value of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2009 resulted in a net pre-tax unrealized gain of $16 million and a net pre-tax unrealized loss of $13 million, respectively (2008 – unrealized losses of $108 million and $6 million, respectively), which were recorded to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sales contracts in the three and nine months ended September 30, 2009 resulted in a net pre-tax unrealized loss of $2 million and a net pre-tax unrealized gain of $7 million, respectively (2008 - unrealized gain of $106 million and unrealized loss of $1 million), 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 September 30, 2009, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $8.1 billion (US$7.6 billion) and a fair value of $9.2 billion (US$8.6 billion). At September 30, 2009, Other Assets included $51 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)*	**September 30, 2009** Fair Value[1]	**September 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]	**40**	**U.S. 1,650**	(218)	U.S. 1,650
U.S. dollar forward foreign exchange contracts (maturing 2009 to 2010)[2]	**7**	**U.S. 635**	(42)	U.S. 2,152
U.S. dollar options (maturing 2009)[2]	**4**	**U.S. 400**	6	U.S. 300
	51	**U.S. 2,685**	(254)	U.S. 4,102

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

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**September 30, 2009** Carrying Amount	**September 30, 2009** Fair Value	December 31, 2008 Carrying Amount	December 31, 2008 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**2,385**	**2,385**	1,300	1,300
Accounts receivable and other assets[2][3]	**983**	**983**	1,404	1,404
Due from TransCanada Corporation	**1,631**	**1,631**	1,529	1,529
Available-for-sale assets[2]	**23**	**23**	27	27
	5,022	**5,022**	4,260	4,260
Financial Liabilities[1][3]				
Notes payable	**1,324**	**1,324**	1,702	1,702
Accounts payable and deferred amounts[4]	**1,590**	**1,590**	1,364	1,364
Due to TransCanada Corporation	**2,757**	**2,757**	1,821	1,821
Accrued interest	**349**	**349**	361	361
Long-term debt and junior subordinated notes	**18,469**	**21,388**	17,367	16,152
Long-term debt of joint ventures	**1,090**	**1,149**	1,076	1,052
	25,579	**28,557**	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 September 30, 2009, the Consolidated Balance Sheet included financial assets of $834 million (December 31, 2008 – $1,257 million) in Accounts Receivable and $172 million (December 31, 2008 - $174 million) in Other Assets.
(3) Recorded at amortized cost.
(4) At September 30, 2009, the Consolidated Balance Sheet included financial liabilities of $1,588 million (December 31, 2008 – $1,342 million) in Accounts Payable and $2 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:

September 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	**$126**	**$129**	**$4**	**$4**	**$35**
Liabilities	**$(71)**	**$(134)**	**$(3)**	**$(64)**	**$(81)**
Notional Values					
Volumes[3]					
Purchases	**9,876**	**204**	**180**	**-**	**-**
Sales	**9,718**	**171**	**228**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**-**	**699**
U.S. dollars	**-**	**-**	**-**	**U.S. 426**	**U.S. 1,425**
Cross-currency	**-**	**-**	**-**	**227/U.S. 157**	**-**
Net unrealized (losses)/gains in the period[4]					
Three months ended September 30, 2009	**$(8)**	**$21**	**$(1)**	**$2**	**$(7)**
Nine months ended September 30, 2009	**$11**	**$(4)**	**$1**	**$4**	**$20**
Net realized gains/(losses) in the period[4]					
Three months ended September 30, 2009	**$23**	**$(43)**	**$1**	**$11**	**$(5)**
Nine months ended September 30, 2009	**$53**	**$(56)**	**-**	**$28**	**$(14)**
Maturity dates	**2009-2014**	**2009-2014**	**2009-2010**	**2009-2012**	**2009-2018**
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[2]					
Assets	**$229**	**$2**	**-**	**-**	**$6**
Liabilities	**$(154)**	**$(15)**	**-**	**$(36)**	**$(67)**
Notional Values					
Volumes[3]					
Purchases	**13,597**	**24**	**-**	**-**	**-**
Sales	**14,806**	**-**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**-**	**-**	**U.S. 1,825**
Cross-currency	**-**	**-**	**-**	**136/U.S. 100**	**-**
Net realized gains/(losses) in the period[4]					
Three months ended September 30, 2009	**$30**	**$(8)**	**-**	**-**	**$(10)**
Nine months ended September 30, 2009	**$108**	**$(28)**	**-**	**-**	**$(27)**
Maturity dates	**2009-2015**	**2009-2012**	**n/a**	**2009- 2013**	**2010-2020**

(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 $6 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2009 were $1 million and $3 million, respectively, and were included in Interest Expense. In third 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 nine months ended September 30, 2009 included gains of $1 million and $2 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 nine months ended September 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 gains/(losses) in the period(3)					
Three months ended September 30, 2008	$5	$(1)	-	-	$5
Nine months ended September 30, 2008	-	$(12)	-	$(7)	$3
Net realized gains/(losses) in the period(3)					
Three months ended September 30, 2008	$12	$(11)	-	$2	$2
Nine months ended September 30, 2008	$21	$(6)	-	$12	$12
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 gains/(losses) in the period(3)					
Three months ended September 30, 2008	$14	$(1)	-	-	$(2)
Nine months ended September 30, 2008	$(24)	$18	-	-	$(4)
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. Net realized gains on fair value hedges for the three and nine months ended September 30, 2008 were $1 million and $1 million, respectively, and were included in Interest Expense. In third 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 nine months ended September 30, 2008 included gains of $7 million and $4 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 nine months ended September 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)*	**September 30, 2009**	December 31, 2008
Current		
Other current assets	**370**	318
Accounts payable	**(359)**	(298)
Long-term		
Other assets	**216**	191
Deferred amounts	**(266)**	(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 September 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2009**	2008	**2009**	2008
Current service cost	**11**	13	**-**	-
Interest cost	**22**	20	**2**	2
Expected return on plan assets	**(24)**	(23)	**-**	-
Amortization of net actuarial loss	**2**	4	**1**	1
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**12**	15	**3**	3

Nine months ended September 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2009**	2008	**2009**	2008
Current service cost	**34**	38	**1**	1
Interest cost	**67**	59	**6**	6
Expected return on plan assets	**(75)**	(69)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**4**	13	**2**	2
Amortization of past service costs	**3**	3	**-**	-
Net benefit cost recognized	**33**	44	**9**	9

8. Acquisitions and Dispositions

On August 14, 2009, TCPL purchased ConocoPhillips' remaining 20 per cent ownership interest in Keystone for US$553 million plus the assumption of US$197 million of short-term indebtedness. The acquisition increased TCPL's ownership interest in Keystone to 100 per cent. The purchase price reflects ConocoPhillips' capital contributions to date and includes an allowance for funds used during construction. TCPL began fully consolidating Keystone in the Pipelines segment upon acquisition.

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 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. TCPL's increased ownership in PipeLines LP resulted in a decrease in Non-Controlling Interests and an increase in Contributed Surplus.

9. Commitments, Guarantees and Contingencies

Commitments

On August 14, 2009, the Company acquired ConocoPhillips' remaining interest in Keystone. As a result, TCPL assumed 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.

Guarantees

As a result of the acquisition of the remaining interest in Keystone, the Company's potential exposure to guarantees of jointly owned entities was reduced by an estimated $305 million to $678 million since December 31, 2008.

Contingencies

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 nine months of 2009 are expected to be repaid.

10. Subsequent Events

Subsequent events have been assessed up to November 3, 2009, which is the date the financial statements were available for issuance.

11. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

		2009		2008	
(millions of dollars)	Maturity Dates	**Outstanding September 30**	**Interest Rate**	Outstanding December 31	Interest Rate
Discount Notes	2009	**1,611**	**0.6%**	1,529	2.1%
Promissory Notes		**20**		-	
		1,631		1,529	

The following amounts are included in Due to TransCanada Corporation:

		2009		2008	
(millions of dollars)	Maturity Dates	**Outstanding September 30**	**Interest Rate**	Outstanding December 31	Interest Rate
Credit Facility	2009	**1,708**	**1.3%**	1,621	5.3%
Credit Facility(1)		**1,049**	**2.3%**	200	4.8%
		2,757		1,821	

(1) This facility was increased to $1.5 billion from $500 million in June 2009.

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: Terry Cunha/Cecily Dobson (403) 920-7859 or (800) 608-7859.

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