Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated July 29, 2010 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) for the three and six months ended June 30, 2010. It should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TCPL's 2009 Annual Report for the year ended December 31, 2009. 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 2009 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 security holders 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, projects 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 (including anticipated construction and completion dates), operating and financial results, and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and 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 not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

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

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, Comparable EBITDA and Comparable 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 and Net Income Applicable to Common Shares.

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 Funds Generated from Operations table in the Liquidity and Capital Resources section of this MD&A.

Consolidated Results of Operations

Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income

For the three months ended June 30	Pipelines		Energy		Corporate		Total	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Comparable EBITDA[1]	**696**	747	**254**	301	**(22)**	(31)	**928**	1,017
Depreciation and amortization	**(251)**	(258)	**(90)**	(87)	**-**	-	**(341)**	(345)
Comparable EBIT[1]	**445**	489	**164**	214	**(22)**	(31)	**587**	672
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	**-**	-	**9**	-	**-**	-	**9**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**-**	-	**6**	(7)	**-**	-	**6**	(7)
EBIT[1]	**445**	489	**179**	207	**(22)**	(31)	**602**	665
Interest expense							**(198)**	(264)
Interest expense of joint ventures							**(15)**	(16)
Interest income and other							**(18)**	34
Income taxes							**(62)**	(95)
Non-controlling interests							**(17)**	(8)
Net Income							**292**	316
Preferred share dividends							**(5)**	(5)
Net Income Applicable to Common Shares							**287**	311
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							**(6)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts							**(4)**	5
Comparable Earnings[1]							**277**	316

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

For the six months ended June 30 *(unaudited)(millions of dollars)*	Pipelines **2010**	2009	Energy **2010**	2009	Corporate **2010**	2009	Total **2010**	2009
Comparable EBITDA[1]	**1,464**	1,618	**513**	591	**(48)**	(61)	**1,929**	2,148
Depreciation and amortization	**(504)**	(518)	**(180)**	(173)	**-**	-	**(684)**	(691)
Comparable EBIT[1]	**960**	1,100	**333**	418	**(48)**	(61)	**1,245**	1,457
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	**-**	-	**(19)**	-	**-**	-	**(19)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**-**	-	**(15)**	(20)	**-**	-	**(15)**	(20)
EBIT[1]	**960**	1,100	**299**	398	**(48)**	(61)	**1,211**	1,437
Interest expense							**(392)**	(565)
Interest expense of joint ventures							**(31)**	(30)
Interest income and other							**6**	56
Income taxes							**(159)**	(209)
Non-controlling interests							**(42)**	(37)
Net Income							**593**	652
Preferred share dividends							**(11)**	(11)
Net Income Applicable to Common Shares							**582**	641
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							**11**	-
Fair value adjustments of natural gas inventory in storage and forward contracts							**11**	14
Comparable Earnings[1]							**604**	655

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

TCPL's Net Income in second quarter 2010 was $292 million and Net Income Applicable to Common Shares was $287 million compared to $316 million and $311 million, respectively, in second quarter 2009. The $24 million decrease in Net Income Applicable to Common Shares reflected:

- decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar;
- decreased EBIT from Energy primarily due to lower volumes and increased operating costs at Bruce A, lower realized prices partially offset by higher volumes at Bruce B, reduced proprietary and third party storage revenues for Natural Gas Storage and the negative impact of a weaker U.S. dollar, partially offset by higher realized power prices in Western Power and increased capacity revenue in U.S. Power;
- decreased Interest Expense primarily due to increased capitalized interest and the positive effect of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by losses in second quarter 2010 compared to gains in 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates;
- a negative impact on Interest Income and Other of losses in second quarter 2010 compared to gains in 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to the strengthening U.S. dollar; and
- decreased Income Taxes due to lower pre-tax earnings and the net positive impact from income tax rate differentials and other income tax adjustments.

The combined negative impact of losses in second quarter 2010 compared to gains in second quarter 2009 for the interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of working capital balances amounted to $58 million.

Comparable Earnings in second quarter 2010 were $277 million compared to $316 million for the same period in 2009. Comparable Earnings in second quarter 2010 excluded net unrealized after tax gains of $6 million ($9 million pre-tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Effective January 1, 2010, these unrealized gains have been removed from Comparable Earnings as they are not expected to be representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable Earnings. Comparable Earnings in second quarter 2010 and 2009 also excluded net unrealized after tax gains of $4 million ($6 million pre-tax) and after tax losses of $5 million ($7 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Pipelines and Energy EBIT is considerably offset by the impact on U.S. dollar-denominated interest expense. The resultant net exposure is managed using derivatives, effectively further reducing the Company's exposure to changes in foreign exchange rates. The average U.S. dollar exchange rate for the three and six months ended June 30, 2010 was 1.03 and 1.03, respectively (2009 - 1.17 and 1.21, respectively).

TCPL's Net Income in the first six months of 2010 was $593 million and Net Income Applicable to Common Shares was $582 million compared to $652 million and $641 million, respectively, for the same periods in 2009. The $59 million decrease in Net Income Applicable to Common Shares reflected:

- decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar, higher business development costs relating to the Alaska pipeline project and lower revenues from certain U.S. pipelines, partially offset by reduced operating, maintenance and administration (OM&A) costs;

- decreased EBIT from Energy primarily due to reduced volumes and higher operating costs at Bruce A, lower realized prices partially offset by higher volumes at Bruce B, lower overall realized power prices at Western Power and reduced earnings at Bécancour, partially offset by increased capacity revenue from U.S. Power and incremental earnings from Portlands Energy which went into service in April 2009;

- decreased Interest Expense primarily due to increased capitalized interest and the positive effect of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by losses in 2010 compared to gains in 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates;

- the negative impact on Interest Income and Other due to losses in 2010 compared to gains in 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to the strengthening U.S. dollar; and

- decreased Income Taxes due to lower pre-tax earnings and the net positive impact from income tax rate differentials and other income tax adjustments.

Comparable Earnings in the first six months of 2010 were $604 million compared to $655 million for the same period in 2009. Comparable Earnings for the first six months of 2010 excluded net unrealized after tax losses of $11 million ($19 million pre-tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable Earnings. Comparable Earnings in the first six months of 2010 and 2009 also excluded net unrealized after tax losses of $11 million ($15 million pre-tax) and $14 million ($20 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Results from each of the segments for the first three and six months in 2010 are discussed further in the Pipelines and Energy sections of this MD&A.

Pipelines

Pipelines' Comparable EBIT and EBIT were $445 million and $960 million in the three and six month periods ended June 30, 2010, respectively, compared to $489 million and $1.1 billion for the same periods in 2009.

Pipelines Results

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Canadian Pipelines				
Canadian Mainline	**263**	288	**528**	572
Alberta System	**176**	177	**351**	345
Foothills	**35**	34	**68**	68
Other (TQM, Ventures LP)	**14**	12	**27**	31
Canadian Pipelines Comparable EBITDA[1]	**488**	511	**974**	1,016
U.S. Pipelines				
ANR	**61**	73	**181**	206
GTN[2]	**41**	49	**86**	110
Great Lakes	**26**	33	**59**	77
PipeLines LP[2][3]	**22**	21	**48**	50
Iroquois	**18**	21	**37**	44
Portland[4]	**1**	2	**11**	16
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**15**	14	**25**	27
General, administrative and support costs[5]	**(3)**	(3)	**(9)**	(6)
Non-controlling interests[6]	**37**	34	**85**	94
U.S. Pipelines Comparable EBITDA[1]	**218**	244	**523**	618
Business Development Comparable EBITDA[1]	**(10)**	(8)	**(33)**	(16)
Pipelines Comparable EBITDA[1]	**696**	747	**1,464**	1,618
Depreciation and amortization	**(251)**	(258)	**(504)**	(518)
Pipelines Comparable EBIT and EBIT[1]	**445**	489	**960**	1,100

(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 until July 1, 2009 when it was sold to PipeLines LP.
(3) PipeLines LP's results reflect TCPL's ownership interest in PipeLines LP of 38.2 per cent in the first six months of 2010 (first six months of 2009 – 32.1 per cent).
(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) Non-controlling interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TCPL.

Net Income for Wholly Owned Canadian Pipelines

(unaudited) *(millions of dollars)*	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Canadian Mainline	**64**	67	**130**	133
Alberta System	**37**	40	**75**	79
Foothills	**7**	6	**13**	12

Canadian Pipelines

Canadian Mainline's net income for the three and six months ended June 30, 2010 decreased $3 million for both periods primarily as a result of lower incentive earnings and a lower rate of return on common equity (ROE) as determined by the National Energy Board (NEB), of 8.52 per cent in 2010 compared to 8.57 per cent in 2009.

Canadian Mainline's Comparable EBITDA for the three and six months ended June 30, 2010 of $263 million and $528 million, respectively, decreased $25 million and $44 million, respectively, compared to the same periods in 2009 primarily due to lower revenues as a result of lower income tax and financial charge components in the 2010 tolls, which are recovered on a flow-through basis and do not impact net income. The decrease in financial charges was primarily due to higher cost historic debt that matured in 2009 and early 2010.

The Alberta System's net income was $37 million in second quarter 2010 and $75 million for the first six months of 2010 compared to $40 million and $79 million for the same periods in 2009. The impact of a higher average investment base in 2010 was more than offset by lower earnings due to the expiration of the 2008-2009 Revenue Requirement Settlement. Net income for the first six months of 2010 currently reflects an ROE of 8.75 per cent on a deemed common equity of 35 per cent. Upon regulatory approval, which is expected to be received in third quarter 2010, TCPL will record the impact of a three year Alberta System settlement with shippers, which includes a 9.70 per cent ROE on a deemed common equity of 40 per cent, retroactive to January 1, 2010. The Company expects this settlement, when approved, to increase net income by approximately $20 million for the first six months of 2010.

The Alberta System's Comparable EBITDA was $176 million in second quarter 2010 and $351 million for the first six months of 2010 compared to $177 million and $345 million for the same periods in 2009. The increase in the six month period was primarily due to higher revenues as a result of a higher return associated with an increased average investment base and a recovery of increased depreciation and income taxes, partially offset by lower earnings due to the expiration of the 2008-2009 Revenue Requirement Settlement. Depreciation and income taxes are recovered on a flow-through basis and do not impact net income.

Comparable EBITDA from Other Canadian Pipelines was $14 million in second quarter 2010 and $27 million for the first six months of 2010, compared to $12 million and $31 million for the same periods in 2009. The decrease in the six months ended June 30, 2010 was primarily due to an adjustment recorded in second quarter 2009 for an NEB decision to retroactively increase TQM's allowed rate of return on capital for 2008 and 2007.

U.S. Pipelines

ANR's Comparable EBITDA for the three and six months ended June 30, 2010 was $61 million and $181 million, respectively, compared to $73 million and $206 million for the same periods in 2009. The decreases were primarily due to the negative impact of a weaker U.S. dollar and lower transportation and storage revenue, partially offset by lower OM&A costs.

GTN's Comparable EBITDA for the three and six months ended June 30, 2010 decreased $8 million and $24 million, respectively, from the same periods in 2009 primarily due to the sale of North Baja to PipeLines LP in July 2009 and the negative impact of a weaker U.S. dollar, partially offset by higher revenues as a result of new long-term firm contracts and lower OM&A costs in 2010.

Comparable EBITDA for the remainder of the U.S. Pipelines was $116 million and $256 million for the three and six months ended June 30, 2010, respectively, compared to $122 million and $302 million for the same periods in 2009. The decreases were primarily due to the negative impact of a weaker U.S. dollar and lower revenues from Great Lakes and Portland, partially offset by increased PipeLines LP earnings which reflected the acquisition of North Baja in July 2009.

Business Development

Pipelines' Business Development Comparable EBITDA decreased $2 million and $17 million in the three and six months ended June 30, 2010 compared to the same periods in 2009 primarily due to higher business development costs related to the continued advancement of the Alaska pipeline project, net of recoveries. The State of Alaska has agreed to reimburse certain of TCPL's eligible pre-construction costs, as they are incurred and approved by the state, to a maximum of US$500 million. The State of Alaska will reimburse up to 50 per cent of the eligible costs incurred prior to the close of the first binding open season. The Company is currently holding an open season that will close on July 30, 2010. Once the first binding open season is closed, the State will reimburse up to 90 per cent of the eligible costs. Together with applicable expenses, such reimbursements are shared proportionately with ExxonMobil, TCPL's joint venture partner in developing the Alaska pipeline project.

Operating Statistics

Six months ended June 30 *(unaudited)*	Canadian Mainline[(1)] 2010	2009	Alberta System[(2)] 2010	2009	Foothills 2010	2009	ANR[(3)] 2010	2009	GTN[(3)] 2010	2009
Average investment base ($millions)	**6,572**	6,566	**4,975**	4,671	**666**	717	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**844**	1,130	**1,723**	1,827	**680**	562	**795**	867	**389**	344
Average per day	**4.7**	6.2	**9.5**	10.1	**3.8**	3.1	**4.4**	4.8	**2.2**	1.9

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Throughput volumes reported in previous years 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 six months ended June 30, 2010 were 645 billion cubic feet (Bcf) (2009 – 883 Bcf); average per day was 3.6 Bcf (2009 – 4.9 Bcf).

(2) Field receipt volumes for the Alberta System for the six months ended June 30, 2010 were 1,740 Bcf (2009 – 1,848 Bcf); average per day was 9.6 Bcf (2009 – 10.2 Bcf).

(3) ANR's and GTN'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.

Mackenzie Gas Pipeline Project

As at June 30, 2010, TCPL had advanced $144 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. The NEB recently concluded final argument hearings for the project and is expected to release its conclusions on the project's application in September 2010. Project timing continues to be uncertain. 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 $164 million in second quarter 2010 compared to $214 million in second quarter 2009. Comparable EBIT in second quarter 2010 excluded net unrealized gains of $9 million resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparable EBIT in second quarter 2010 and 2009 also excluded net unrealized gains of $6 million and net unrealized losses of $7 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Energy's Comparable EBIT was $333 million in the first six months of 2010 compared to $418 million in the same six months of 2009. Comparable EBIT excluded net unrealized losses of $19 million resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparable EBIT in the first six months of 2010 and 2009 also excluded net unrealized losses of $15 million and $20 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Items excluded from Comparable Earnings are discussed further under the headings U.S. Power and Natural Gas Storage in this section.

Energy Results

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Canadian Power				
Western Power	**85**	59	**127**	152
Eastern Power[1]	**46**	60	**98**	112
Bruce Power	**47**	102	**110**	201
General, administrative and support costs	**(5)**	(11)	**(15)**	(19)
Canadian Power Comparable EBITDA[2]	**173**	210	**320**	446
U.S. Power				
Northeast Power[3]	**81**	76	**156**	118
General, administrative and support costs	**(9)**	(11)	**(18)**	(23)
U.S. Power Comparable EBITDA[2]	**72**	65	**138**	95
Natural Gas Storage				
Alberta Storage	**20**	36	**73**	75
General, administrative and support costs	**(2)**	(2)	**(4)**	(5)
Natural Gas Storage Comparable EBITDA[2]	**18**	34	**69**	70
Business Development Comparable EBITDA[2]	**(9)**	(8)	**(14)**	(20)
Energy Comparable EBITDA[2]	**254**	301	**513**	591
Depreciation and amortization	**(90)**	(87)	**(180)**	(173)
Energy Comparable EBIT[2]	**164**	214	**333**	418
Specific items:				
Fair value adjustments of U.S. Power derivative contracts	**9**	-	**(19)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**6**	(7)	**(15)**	(20)
Energy EBIT[2]	**179**	207	**299**	398

(1) Includes Portlands Energy effective April 2009.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.
(3) Includes phase one of Kibby Wind effective October 2009.

Canadian Power

Western and Eastern Canadian Power Comparable EBITDA[1][2]

(unaudited) *(millions of dollars)*	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Revenues				
Western power	**202**	174	**366**	389
Eastern power	**65**	71	**132**	140
Other[3]	**15**	30	**37**	42
	282	275	**535**	571
Commodity Purchases Resold				
Western power	**(99)**	(109)	**(205)**	(207)
Other[3][4]	**(7)**	(6)	**(12)**	(15)
	(106)	(115)	**(217)**	(222)
Plant operating costs and other	**(45)**	(43)	**(93)**	(87)
General, administrative and support costs	**(5)**	(11)	**(15)**	(19)
Other income	**-**	2	**-**	2
Comparable EBITDA[1]	**126**	108	**210**	245

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.
(2) Includes Portlands Energy effective April 2009.
(3) Includes sales of excess natural gas purchased for generation and thermal carbon black. Effective January 1, 2010, the net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues. Comparative results for 2009 reflect amounts reclassified from Other Commodity Purchases Resold to Other Revenues.
(4) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics[1]

(unaudited)	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Sales Volumes (GWh)				
Supply				
Generation				
Western Power	**594**	572	**1,179**	1,177
Eastern Power	**395**	421	**824**	776
Purchased				
Sundance A & B and Sheerness PPAs	**2,459**	2,725	**5,114**	5,165
Other purchases	**73**	122	**222**	307
	3,521	3,840	**7,339**	7,425
Sales				
Contracted				
Western Power	**2,573**	2,597	**4,842**	4,650
Eastern Power	**395**	419	**840**	810
Spot				
Western Power	**553**	824	**1,657**	1,965
	3,521	3,840	**7,339**	7,425
Plant Availability				
Western Power[2]	**94%**	93%	**94%**	92%
Eastern Power	**97%**	98%	**97%**	98%

(1) Includes Portlands Energy effective April 2009.
(2) Excludes facilities that provide power to TCPL under PPAs.

Western Power's Comparable EBITDA of $85 million and Power Revenues of $202 million in second quarter 2010 increased $26 million and $28 million, respectively, compared to the same period in 2009, primarily due to increased revenues from the Alberta power portfolio resulting from higher realized power prices. Average spot market power prices in Alberta increased 150 per cent to $80 per megawatt hour (MWh) in second quarter 2010 compared to $32 per MWh in second quarter 2009. Spot market sales represented 18 per cent of Western Power's total sales in second quarter 2010.

Western Power's Comparable EBITDA of $127 million and Power Revenues of $366 million in the first six months of 2010 decreased $25 million and $23 million, respectively, compared to the same period in 2009, primarily due to lower overall realized power prices.

Eastern Power's Comparable EBITDA of $46 million and $98 million for the three and six months ended June 30, 2010, decreased $14 million compared to each of the same periods in 2009. Decreased revenues due to lower contracted earnings from Bécancour and unfavourable wind conditions at Cartier Wind were partially offset by incremental earnings from Portlands Energy, which went into service in April 2009. Results from Bécancour are consistent with the expected contracted earnings according to the original electricity supply contract with Hydro-Québec and are variable due to the timing of maintenance cycles under the contract.

Western Power manages the sale of its supply volumes on a portfolio basis. A portion of its supply is sold into the spot market to assure supply in the event of an unexpected plant outage. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where Western Power would otherwise have to purchase electricity in the open market to fulfill its contractual sales obligations. Approximately 82 per cent of Western Power sales volumes were sold under contract in second quarter 2010, compared to 76 per cent in second quarter 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2010, Western Power had entered into fixed-price power sales contracts to sell approximately 4,700 gigawatt hours (GWh) for the remainder of 2010 and 6,700 GWh for 2011.

Eastern Power is focused on selling power under long-term contracts. In second quarter 2010 and 2009, all of Eastern Power's sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for 2010 and 2011.

Bruce Power Results

(TCPL's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended June 30 **2010**	 2009	Six months ended June 30 **2010**	 2009
Revenues(1)	**197**	240	**422**	461
Operating Expenses	**(150)**	(138)	**(312)**	(260)
Comparable EBITDA(2)	**47**	102	**110**	201
Bruce A Comparable EBITDA(2)	**10**	47	**23**	88
Bruce B Comparable EBITDA(2)	**37**	55	**87**	113
Comparable EBITDA(2)	**47**	102	**110**	201
Bruce Power – Other Information				
Plant availability				
Bruce A	**72%**	100%	**69%**	99%
Bruce B	**86%**	75%	**92%**	86%
Combined Bruce Power	**82%**	83%	**85%**	90%
Planned outage days				
Bruce A	**25**	-	**60**	-
Bruce B	**47**	45	**47**	45
Unplanned outage days				
Bruce A	**22**	-	**48**	5
Bruce B	**-**	33	**6**	41
Sales volumes (GWh)				
Bruce A	**1,121**	1,563	**2,110**	3,058
Bruce B	**1,944**	1,662	**4,099**	3,801
	3,065	3,225	**6,209**	6,859
Results per MWh				
Bruce A power revenues	**$65**	$64	**$64**	$64
Bruce B power revenues(3)	**$59**	$70	**$58**	$63
Combined Bruce Power revenues	**$60**	$68	**$60**	$63
Percentage of Bruce B output sold to spot market(4)	**75%**	40%	**77%**	38%

(1) Revenues include Bruce A's fuel cost recoveries of $9 million and $14 million for the three and six months ended June 30, 2010, respectively (2009 – $11 million and $21 million). Revenues also include Bruce B unrealized losses of nil and $1 million as a result of changes in the fair value of power derivatives for the three and six months ended June 30, 2010, respectively (2009 – gains of nil and $2 million).

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

(3) Includes revenues received under the floor price mechanism and contract settlements.

(4) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TCPL's proportionate share of Bruce Power's Comparable EBITDA decreased $55 million to $47 million in second quarter 2010 compared to $102 million in second quarter 2009.

TCPL's proportionate share of Bruce A's Comparable EBITDA decreased $37 million to $10 million in second quarter 2010 compared to $47 million in second quarter 2009 as a result of decreased volumes and higher operating costs due to increased planned and unplanned outage days. Bruce A's plant availability in second quarter 2010 was 72 per cent as a result of 47 outage days compared to an availability of 100 per cent and no outage days in the same period in 2009.

TCPL's proportionate share of Bruce B's Comparable EBITDA decreased $18 million to $37 million in second quarter 2010 compared to $55 million in second quarter 2009 primarily due to lower realized prices resulting from the expiration of fixed-price contracts at higher prices, partially offset by higher volumes due to a decrease in outage days.

In second quarter 2009, Bruce B's contract with the Ontario Power Authority (OPA) was amended such that, beginning in 2009, annual net payments received under the floor price mechanism will not be subject to repayment in future years. The support payments recognized by Bruce B in second quarter 2009 included an amount related to first quarter 2009. This amount has been excluded from the realized price calculation for second quarter 2009.

Amounts received under the Bruce B floor price mechanism during the year are subject to repayment if the annual average spot price exceeds the annual average floor price. With respect to 2010, TCPL currently expects average spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenue in the first six months of 2010 are expected to be repaid.

TCPL's proportionate share of Bruce Power's Comparable EBITDA decreased $91 million to $110 million in the six months ended June 30, 2010 compared to the same period in 2009 as a result of lower volumes and higher operating costs due to higher planned and unplanned outage days at Bruce A, partially offset by the impact of a payment made in first quarter 2010 from Bruce B to Bruce A regarding 2009 amendments to the agreement with the OPA. The net positive impact to TCPL in 2010 reflected TCPL's higher percentage ownership in Bruce A.

Under a contract with the OPA, all of the output from Bruce A in second quarter 2010 was sold at a fixed price of $64.71 per MWh (before recovery of fuel costs from the OPA) compared to $64.45 per MWh in second quarter 2009. All output from the Bruce B units was subject to a floor price of $48.96 per MWh in second quarter 2010 and $48.76 per MWh in second quarter 2009. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

Bruce B also enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price of $59 per MWh in second quarter 2010 reflected revenues recognized from both the floor price mechanism and contract sales. A significant portion of these contracts will expire by the end of 2010, which is expected to result in lower realized prices at Bruce B for future periods. At June 30, 2010, Bruce B had sold forward approximately 1,000 GWh and 300 GWh, representing TCPL's proportionate share, for the remainder of 2010 and 2011, respectively.

The overall plant availability percentage in 2010 is expected to be in the low 80s for the two operating Bruce A units and in the low 90s for the four Bruce B units. A planned outage of Bruce A Unit 3 began in late February 2010 and ended in late April 2010. A planned outage on Bruce B Unit 6 commenced mid-May 2010 with the unit returning to service late July 2010. A maintenance outage scheduled for mid-October 2010 for Bruce B Unit 5 has been reduced from ten weeks to three weeks.

As at June 30, 2010, Bruce A had incurred approximately $3.6 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

U.S. Power Comparable EBITDA(1)(2)

(unaudited) *(millions of dollars)*	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Revenues				
Power(3)	**244**	202	**485**	457
Capacity	**68**	54	**110**	84
Other(3)(4)	**16**	11	**42**	57
	328	267	**637**	598
Commodity purchases resold(3)	**(115)**	(67)	**(257)**	(189)
Plant operating costs and other(4)	**(132)**	(124)	**(224)**	(291)
General, administrative and support costs	**(9)**	(11)	**(18)**	(23)
Comparable EBITDA(1)	**72**	65	**138**	95

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of Comparable EBITDA.
(2) Includes phase one of Kibby Wind effective October 2009.
(3) Effective January 1, 2010, the net impact of derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets is presented on a net basis in Power Revenues. Comparative results for 2009 reflect amounts reclassified from Commodity Purchases Resold and Other Revenues to Power Revenues.
(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics(1)

(unaudited)	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Sales Volumes (GWh)				
Supply				
Generation	**1,789**	1,404	**2,680**	2,572
Purchased	**2,061**	1,135	**4,547**	2,394
	3,850	2,539	**7,227**	4,966
Sales				
Contracted	**3,669**	2,266	**6,884**	4,406
Spot	**181**	273	**343**	560
	3,850	2,539	**7,227**	4,966
Plant Availability	**92%**	78%	**89%**	68%

(1) Includes phase one of Kibby Wind effective October 2009.

U.S. Power's Comparable EBITDA for the three months ended June 30, 2010 was $72 million, an increase of $7 million compared to the same period in 2009. The increase was primarily due to higher volumes of power sold and increased capacity revenues, partially offset by the negative impact of a weaker U.S. dollar. For the six months ended June 30, 2010, U.S. Power's EBITDA of $138 million increased $43 million from the same period in 2009 primarily due to increased capacity revenues and a first quarter 2010 adjustment of Ravenswood's 2009 operating costs, partially offset by the negative impact of a weaker U.S. dollar.

U.S. Power's Power Revenues for the three and six months ended June 30, 2010 of $244 million and $485 million, respectively, increased from $202 million and $457 million in the same periods in 2009 primarily due to higher volumes of power sold, partially offset by the negative impact of a weaker U.S. dollar and lower realized power prices. Capacity Revenues increased for the three and six months ended June 30, 2010 to $68 million and $110 million, respectively, primarily due to higher capacity prices as a result of the long-planned retirement of a power generating facility owned by the New York Power Authority, which occurred at the end of January 2010, partially offset by the Unit 30 outage from September 2008 to May 2009, which has a greater impact on 2010 capacity revenues due to the nature of the calculations.

Commodity Purchases Resold of $115 million and $257 million for the three and six months ended June 30, 2010, respectively, increased from $67 million and $189 million in the same periods in 2009 primarily due to an increase in the quantity of power purchased for resale under its power sales commitments in New England, partially offset by the positive impact of a weaker U.S. dollar, as well as lower contracted power prices per MWh for the six months ended June 30, 2010.

Plant Operating Costs and Other in the three months ended June 30, 2010 were $132 million, an increase of $8 million over the same period in 2009 primarily due to increased volumes, partially offset by the positive impact of a weaker U.S. dollar. In the six months ended June 30, 2010, Plant Operating Costs and Other were $224 million, a decrease of $67 million compared to the same period in 2009 primarily due to the positive impact of a weaker U.S. dollar and the cumulative impact of the Ravenswood prior year adjustment.

In both the three and six months ended June 30, 2010, 95 per cent of power sales volumes were sold under contract, compared to 89 per cent for the same periods in 2009. U.S. Power is focused on selling the majority of its power under contract to wholesale, commercial and industrial customers, while managing a portfolio of power supplies sourced from its own generation and wholesale power purchases. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 6,800 GWh for the remainder of 2010 and 8,600 GWh for 2011, including financial contracts to effectively lock in a margin on forecasted generation. Certain contracted volumes are dependent on customer usage levels and actual amounts contracted in future periods will depend on market liquidity and other factors.

Comparable EBITDA excluded net unrealized gains of $9 million and net unrealized losses of $19 million in the three and six months ended June 30, 2010, respectively, resulting from changes in the fair value of certain U.S. Power derivative contracts. Power is purchased under forward contracts to satisfy a significant portion of U.S. Power's wholesale, commercial and industrial power sales commitments, mitigating its exposure to fluctuations in spot market prices and effectively locking in a positive margin. In addition, power generation is managed by entering into contracts to sell a portion of power forecasted to be generated. Contracts are entered into simultaneously to purchase the fuel required to generate the power to reduce exposure to market price volatility and effectively lock in positive margins. Each of these contracts provide economic hedges which, in some cases, do not meet the specific criteria required for hedge accounting treatment and therefore are recorded at their fair value based on forward market prices. Effective January 1, 2010, the unrealized gains and losses from these contracts have been removed from Comparable EBITDA as they are not representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable EBITDA.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA for the three and six month periods ended June 30, 2010, was $18 million and $69 million, respectively, compared to $34 million and $70 million for the same periods in 2009. The decrease in Comparable EBITDA in second quarter 2010 was primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas price spreads. The seasonal nature of natural gas storage generally results in higher revenues in the winter season.

Comparable EBITDA excluded net unrealized gains of $6 million and net unrealized losses of $15 million in the three and six months ended June 30, 2010, respectively (2009 – losses of $7 million and $20 million), 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 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.

Other Income Statement Items

Interest Expense

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Interest on long-term debt[(1)]	**297**	330	**593**	665
Other interest and amortization	**44**	(3)	**76**	17
Capitalized interest	**(143)**	(63)	**(277)**	(117)
	198	264	**392**	565

(1) Includes interest for Junior Subordinated Notes.

Interest Expense for second quarter 2010 decreased $66 million to $198 million from $264 million in second quarter 2009. Interest Expense for the six months ended June 30, 2010 decreased $173 million to $392 million from $565 million for the six months ended June 30, 2009. The decreases reflected increased capitalized interest to finance the Company's capital growth program in 2010, primarily due to Keystone construction, and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest. These decreases were partially offset by incremental interest expense on new debt issues of US$1.25 billion in June 2010 and $700 million in February 2009, and by losses in 2010 compared to gains in 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates.

Interest Income and Other for second quarter 2010 was an expense of $18 million compared to income of $34 million for second quarter 2009. Interest Income and Other for the six months ended June 30, 2010 decreased $50 million to $6 million from $56 million for the six months ended June 2009. Interest Income and Other was negatively impacted by losses in 2010 compared to gains in 2009 from derivatives used to manage the Company's exposure to foreign exchange fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to a strengthening U.S. dollar.

Income Taxes were $62 million in second quarter 2010 compared to $95 million for the same period in 2009. Income taxes for the six months ended June 30, 2010 were $159 million compared to $209 million for the same period in 2009. The decreases were primarily due to reduced pre-tax earnings and the net positive impact from income tax rate differentials and other income tax adjustments. In second quarter 2010, the Company recorded a benefit in Current Income Taxes and an offsetting provision in Future Income Taxes as a result of bonus depreciation for U.S. income tax purposes on Keystone assets placed into service June 30, 2010.

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 to provide for planned growth. TCPL's liquidity position remains solid, underpinned by predictable cash flow from operations, significant cash balances on hand from recent common share and debt issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2010, December 2012, December 2012 and February 2013, respectively. At June 30, 2010, draws of US$300 million had been made on these facilities, which also support the Company's two commercial paper programs in Canada. In addition, TCPL's proportionate share of capacity remaining available on committed bank facilities at TCPL-operated affiliates was $165 million with maturity dates from 2010 through 2012. As at June 30, 2010, TCPL had remaining capacity of $2.0 billion and US$2.75 billion under its Canadian debt and U.S. debt shelf prospectuses, respectively. TCPL's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section of this MD&A.

At June 30, 2010, the Company held Cash and Cash Equivalents of $1.1 billion compared to $1.0 billion at December 31, 2009. The increase in Cash and Cash Equivalents was primarily due to cash generated from operations, proceeds from the issuance of senior notes in second quarter 2010 and preferred shares in first and second quarter 2010, partially offset by capital expenditures.

Operating Activities

Funds Generated from Operations[(1)]

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Cash Flows				
Funds generated from operations[(1)]	**922**	686	**1,634**	1,446
(Increase)/decrease in operating working capital	**(316)**	236	**(200)**	331
Net cash provided by operations	**606**	922	**1,434**	1,777

(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 $316 million and $343 million for the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009, primarily due to increases in operating working capital. Funds Generated from Operations for the three and six months ended June 30, 2010 were $922 million and $1.6 billion, respectively, compared to $686 million and $1.4 billion for the same periods in 2009. The increases for the three and six months ended June 30, 2010 were primarily due to the income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed into service on June 30, 2010, partially offset by lower earnings.

Investing Activities

TCPL remains committed to executing its previously announced $22 billion capital expenditure program. For the three and six months ended June 30, 2010, capital expenditures totalled $1.0 billion and $2.3 billion, respectively (2009 - $1.3 billion and $2.4 billion), primarily related to the construction of Keystone, expansion of the Alberta System, refurbishment and restart of Bruce A Units 1 and 2, and construction of the Guadalajara natural gas pipeline and Coolidge power plant.

Financing Activities

In June 2010, TCPL issued senior notes of US$500 million and US$750 million maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

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. TCPL will also continue to examine opportunities for portfolio management, including a role for PipeLines LP, in financing its capital program.

In the three and six months ended June 30, 2010, TCPL issued $1.3 billion (2009 – nil and $3.1 billion), and retired $142 million and $283 million, respectively (2009 - $18 million and $500 million), of Long-Term Debt. Notes Payable decreased $441 million and $9 million in the three and six months ended June 30, 2010, respectively, compared to an increase of $233 million and a decrease of $684 million for the same periods in 2009.

Dividends

On July 29, 2010, TCPL's Board of Directors declared a quarterly dividend for the quarter ending September 30, 2010 in the aggregate amount equal to the quarterly dividend paid on TransCanada Corporation's (TransCanada) issued and outstanding common shares at the close of business on September 30, 2010. The dividend is payable on October 29, 2010. The Board also declared a dividend 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 (DRP) for the dividends payable October 29, 2010. Under this plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. TransCanada reserves the right to alter the discount or return to fulfilling DRP participation by purchasing shares on the open market at any time.

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, 2009. For further information on the Company's accounting policies and estimates refer to the MD&A in TCPL's 2009 Annual Report.

Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TCPL's 2009 Annual Report. Future accounting changes that will impact the Company are as follows:

Future Accounting Changes

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) previously 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. As an SEC registrant, TCPL has the option to prepare and file its consolidated financial statements using U.S. GAAP. Previously, TCPL disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. Prior to the developments noted below, the Company's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

Rate-Regulated Accounting

In accordance with Canadian GAAP, TCPL currently follows specific accounting policies unique to a rate-regulated business which are consistent with rate-regulated accounting (RRA) standards in U.S. GAAP. Under RRA, the timing of recognition of certain expenses and revenues may differ from that otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing differences are recorded as regulatory assets and regulatory liabilities on TCPL's consolidated balance sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the applicable regulatory authorities. As at June 30, 2010, TCPL reported $1.7 billion of regulatory assets and $0.4 billion of regulatory liabilities using RRA in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities" which proposed a form of RRA under IFRS. To date, the IASB has not approved an RRA standard and TCPL does not expect a final RRA standard under IFRS, to be effective for 2011. As a result, in July 2010, the CICA's AcSB issued an Exposure Draft applicable to Canadian publicly accountable enterprises that use RRA, which, if approved, would allow these entities to defer the adoption of IFRS for two years. A final decision is expected by the AcSB before the end of 2010. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, if the AcSB Exposure Draft is approved, TCPL expects to defer its adoption of IFRS accordingly, and continue to prepare its consolidated financial statements in accordance with Canadian GAAP to maintain the use of RRA. During the deferral period, TCPL will continue to actively monitor IASB developments with respect to RRA. If the AcSB Exposure Draft is not approved or the IASB has not approved an RRA standard within the two year deferral period that allows the Company's rate-regulated activities to be appropriately reflected in its consolidated financial statements, TCPL expects to re-evaluate its decision to adopt IFRS and reconsider the adoption of U.S. GAAP.

As a result of these developments related to RRA under IFRS, TCPL cannot reasonably quantify the full impact that adopting IFRS would have on its financial position and future results if it proceeded with adopting IFRS. The Company will continue to monitor non-RRA IFRS developments and their potential impact on TCPL.

Contractual Obligations

At June 30, 2010, TCPL had entered into agreements totalling approximately $530 million to purchase construction materials and services for the Bison natural gas pipeline and Cartier Wind power projects. Other than these commitments and expected increased payments for long-term debt resulting from new debt issuances as discussed in the Liquidity and Capital Resources section of this MD&A, there have been no material changes to TCPL's contractual obligations from December 31, 2009 to June 30, 2010, 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 2009 Annual Report.

Financial Instruments and Risk Management

TCPL continues to manage and monitor its exposure to counterparty credit, liquidity and market 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 of accounts receivable, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At June 30, 2010, there were no significant amounts past due or impaired.

At June 30, 2010, the Company had a credit risk concentration of $348 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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.

Natural Gas Inventory

At June 30, 2010, 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 $51 million (December 31, 2009 - $73 million). The change in fair value of proprietary natural gas inventory in storage in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of $4 million and net pre-tax unrealized losses of $20 million, respectively, which were recorded as an increase and a decrease, respectively, to Revenues and Inventories (2009 - losses of $6 million and $29 million). The change in fair value of natural gas forward purchase and sale contracts in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of $2 million and $5 million, respectively (2009 – losses of $1 million and gains of $9 million), which were included in Revenues.

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 $7 million at June 30, 2010 (December 31, 2009 – $12 million). The decrease from December 31, 2009 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At June 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.4 billion (US$8.8 billion) and a fair value of $9.7 billion (US$9.2 billion). At June 30, 2010, $20 million (December 31, 2009 - $96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional principal amounts for the derivatives designated as a net investment hedge were as follows:

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**June 30, 2010** Fair Value[1]	**June 30, 2010** Notional or Principal Amount	December 31, 2009 Fair Value[1]	December 31, 2009 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**37**	**U.S. 2,100**	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	**(17)**	**U.S. 550**	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	**-**	**-**	1	U.S. 100
	20	**U.S. 2,650**	96	U.S. 2,715

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**June 30, 2010** Carrying Amount	**June 30, 2010** Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**1,126**	**1,126**	979	979
Accounts receivable and other[2][3]	**1,343**	**1,384**	1,433	1,484
Due from TransCanada Corporation	**618**	**618**	845	845
Available-for-sale assets[2]	**20**	**20**	23	23
	3,107	**3,148**	3,280	3,331
Financial Liabilities[1][3]				
Notes payable	**1,697**	**1,697**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,291**	**1,291**	1,532	1,532
Due to TransCanada Corporation	**2,240**	**2,240**	2,069	2,069
Accrued interest	**369**	**369**	380	380
Long-term debt	**17,845**	**21,125**	16,664	19,377
Junior subordinated notes	**1,050**	**1,072**	1,036	976
Long-term debt of joint ventures	**911**	**1,011**	965	1,025
	25,403	**28,805**	24,333	27,046

(1) Consolidated Net Income in 2010 included gains of $9 million (2009 – $8 million) for fair value adjustments related to interest rate swap agreements on US$150 million (2009 – US$300 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At June 30, 2010, the Consolidated Balance Sheet included financial assets of $868 million (December 31, 2009 – $968 million) in Accounts Receivable, $42 million in Other Current Assets (December 31, 2009 – nil) and $453 million (December 31, 2009 - $488 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for certain long-term debt which is recorded at fair value.

(4) At June 30, 2010, the Consolidated Balance Sheet included financial liabilities of $1,262 million (December 31, 2009 – $1,507 million) in Accounts Payable and $29 million (December 31, 2009 - $25 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

June 30, 2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$210**	**$146**	**-**	**$29**
Liabilities	**$(158)**	**$(145)**	**$(20)**	**$(90)**
Notional Values				
Volumes[3]				
Purchases	**13,165**	**117**	**-**	**-**
Sales	**14,285**	**89**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**960**
U.S. dollars	**-**	**-**	**U.S. 1,143**	**U.S. 1,525**
Cross-currency	**-**	**-**	**47/U.S. 37**	**-**
Net unrealized (losses)/gains in the period[4]				
Three months ended June 30, 2010	**$(10)**	**$3**	**$(11)**	**$(13)**
Six months ended June 30, 2010	**$(26)**	**$5**	**$(11)**	**$(17)**
Net realized gains/(losses) in the period[4]				
Three months ended June 30, 2010	**$15**	**$(17)**	**$(6)**	**$(6)**
Six months ended June 30, 2010	**$37**	**$(29)**	**$2**	**$(10)**
Maturity dates	**2010-2015**	**2010-2014**	**2010-2012**	**2010-2018**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$124**	**$1**	**-**	**$9**
Liabilities	**$(237)**	**$(54)**	**$(37)**	**$(116)**
Notional Values				
Volumes[3]				
Purchases	**14,792**	**63**	**-**	**-**
Sales	**15,209**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**U.S. 120**	**U.S. 1,975**
Cross-currency	**-**	**-**	**136/U.S. 100**	**-**
Net realized losses in the period[4]				
Three months ended June 30, 2010	**$(36)**	**$(6)**	**-**	**$(9)**
Six months ended June 30, 2010	**$(43)**	**$(9)**	**-**	**$(19)**
Maturity dates	**2010-2015**	**2010-2012**	**2010- 2014**	**2011-2020**

(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 and natural gas derivatives are in GWh and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on power and natural gas 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 $9 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and six months ended June 30, 2010 were $1 million and $2 million, respectively, and were included in Interest Expense. In second quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three and six months ended June 30, 2010 included gains of $7 million and losses of $1 million, respectively, for changes in the 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 for the three and six months ended June 30, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2009 *(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)(2)]					
Assets	$150	$107	$5	-	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values[(2)]					
Volumes[(3)]					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/U.S. 157	-
Net unrealized (losses)/gains in the period[(4)]					
Three months ended June 30, 2009	$(2)	$10	$(5)	$1	$27
Six months ended June 30, 2009	$19	$(25)	$2	$2	$27
Net realized gains/(losses) in the period[(4)]					
Three months ended June 30, 2009	$20	$(39)	$2	$11	$(5)
Six months ended June 30, 2009	$30	$(13)	$(1)	$17	$(9)
Maturity dates[(2)]	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[(5)(6)]					
Fair Values[(1)(2)]					
Assets	$175	$2	-	-	$15
Liabilities	$(148)	$(22)	-	$(43)	$(50)
Notional Values[(2)]					
Volumes[(3)]					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period[(4)]					
Three months ended June 30, 2009	$52	$(10)	-	-	$(10)
Six months ended June 30, 2009	$78	$(20)	-	-	$(17)
Maturity dates[(2)]	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.
(2) As at December 31, 2009.
(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million at December 31, 2009. Net realized gains on fair value hedges for the three and six months ended June 30, 2009 were $1 million and $2 million, respectively, and were included in Interest Expense. In second quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three and six months ended June 30, 2009 included losses of $4 million and gains of $1 million, respectively, for changes in the 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 for the three and six months ended June 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**June 30, 2010**	December 31, 2009
Current		
Other current assets	**311**	315
Accounts payable	**(406)**	(340)
Long-term		
Intangibles and other assets	**228**	260
Deferred amounts	**(451)**	(272)

Controls and Procedures

As of June 30, 2010, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of TCPL's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TCPL's disclosure controls and procedures were effective as at June 30, 2010.

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.

Outlook

Since the disclosure in TCPL's 2009 Annual Report, the Company's earnings outlook for 2010 is relatively unchanged as the Company expects reduced EBITDA from Keystone to be offset by higher capitalized interest. Although the Company's expectation for market power prices has improved in second quarter 2010, Energy's EBIT is still subject to volatility in market power prices. For further information on outlook, refer to the MD&A in TCPL's 2009 Annual Report.

Recent Developments

Pipelines

Keystone

In June 2010, line fill on the first phase of the Keystone oil pipeline was completed and on June 30, 2010, the pipeline was placed into commercial service. The first phase of Keystone extends from Hardisty, Alberta to serve markets in Wood River and Patoka, Illinois and has an initial nominal capacity of 435,000 barrels per day (Bbl/d). As part of the NEB's approval to begin operations, Keystone will operate at a reduced maximum operating pressure (MOP), which will reduce throughput capacity below initial nominal capacity. As required by the NEB, additional in-line inspections on the Canadian segment of the pipeline have been completed. Analysis of the data from these inspections, any remedial work if necessary, and removal of the MOP restriction are expected to be completed in fourth quarter 2010.

Construction of the second phase of Keystone to expand nominal capacity to 591,000 Bbl/d and extend the pipeline to Cushing, Oklahoma began in second quarter 2010. Commercial in service of the second phase is expected to occur in first quarter 2011.

Keystone is planning 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 U.S. Gulf Coast in first quarter 2013. The Keystone expansion will extend from Hardisty to a delivery point near existing terminals in Port Arthur, Texas. In March 2010, the NEB approved the Company's application to construct and operate the Canadian portion of the Keystone expansion. In April 2010, the U.S. Department of State, the lead agency for federal regulatory approvals, issued a Draft Environmental Impact Statement which concluded that Keystone's expansion to the Gulf Coast would have limited environmental impact. In June 2010, the Department of State solicited the views of specifically identified federal departments and agencies, including the Department of Energy and the Environmental Protection Agency, on whether granting the approvals for Keystone would be in the national interest, requesting a response by September 2010. After consultation with those agencies, the Department of State has decided to provide those agencies with the full benefit of the final Environmental Impact Statement before starting the 90 day period within which those agencies provide their comments to the Department of State. Assuming regulatory approval is granted in first quarter 2011, construction is expected to begin shortly thereafter.

In response to significant market demand, the Company is pursuing opportunities to attract growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to Keystone for delivery to major U.S. refining markets. Commercial definition and project scoping are underway and the Company expects to launch an open season in third quarter 2010. Commercial in service is anticipated in first quarter 2013, subject to the results of the open season.

The total capital cost of Keystone is expected to be approximately US$12 billion. Approximately US$6 billion has been spent to date, including approximately US$800 million for the expansion to the Gulf Coast, with the remaining US$6 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.

Although the first phase of Keystone is now in commercial service, all cash flow related to Keystone is expected to be capitalized until the MOP restriction has been removed. TCPL expects Keystone to begin recording EBITDA in fourth quarter 2010 when the MOP restriction on the Canadian segment is expected to be removed, with EBITDA increasing through 2011, 2012 and 2013 as subsequent phases are placed in service. Based on current long-term commitments of 910,000 Bbl/d, Keystone is expected to generate EBITDA of approximately US$1.2 billion in 2013, its first full year of commercial operation serving both the U.S. Midwest and Gulf Coast markets. If volumes increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate approximately US$1.5 billion of annual EBITDA. In the future, Keystone can be economically expanded from 1.1 million Bbl/d to 1.5 million Bbl/d in response to additional market demand.

Three entities, each of which had entered into Transportation Service Agreements for the second phase of the Keystone pipeline, have filed separate Statements of Claim against certain of TCPL's Keystone subsidiaries in the Alberta Court of Queen’s Bench, seeking declaratory relief or alternatively, damages in varying amounts. Only one of these Statements of Claim has been served on the Keystone subsidiaries. The Company believes each of the claims to be without merit and will vigorously defend these actions.

Canadian Mainline

Tolls on the Canadian Mainline in any year are based, in part, on projected throughput volumes for the year. Estimated throughput volumes for 2010 are now expected to be lower than was used in setting tolls for 2010. As a result, revenues are projected to be ten per cent to 15 per cent less than anticipated. This revenue shortfall is expected to be collected in future tolls.

TCPL has developed a comprehensive proposal concerning rate design services and business model that responds to changing market dynamics. This proposal was conveyed to customers at the end of first quarter 2010 and discussions with customers are continuing. A related NEB filing is anticipated before year end.

With the objective of maintaining markets and competitive position, TCPL has signed precedent agreements for 100,000 gigajoules per day for ten years to move Marcellus shale natural gas from Niagara, Ontario to Eastern Canadian markets. In response to continuing customer interest, TCPL has initiated a further open season for new capacity for service from Niagara and Chippawa, Ontario.

Alberta System

In June 2010, TCPL reached a three year settlement agreement with Alberta System shippers and other interested parties and filed a 2010 – 2012 Revenue Requirement Settlement Application with the NEB. The settlement provides for a cost of capital reflecting a 9.70 per cent ROE on deemed common equity of 40 per cent and includes a fixed amount for certain OM&A costs. Variances between actual and agreed to OM&A costs will accrue to TCPL. All other cost elements of the revenue requirement will be treated on a flow-through basis. TCPL expects to receive regulatory approval from the NEB of the settlement in third quarter 2010.

TCPL anticipates filing for final rates in 2010 pending NEB approval of the 2010 – 2012 Revenue Requirement Settlement Application and the application for the Alberta System rate design and commercial and operational integration of the Canadian Utilities Limited (ATCO Pipelines) system.

Construction of the Groundbirch pipeline is expected to begin in August 2010 and is estimated to be in service by November 2010. When completed, the project will consist of a natural gas pipeline that will extend the Alberta System, connecting to natural gas supplies in the Montney shale gas formation in northeast B.C. The approximate $200 million project has firm transportation contracts that will reach 1.1 billion cubic feet per day by 2014.

TCPL continues to advance the Horn River natural gas pipeline project which will bring northeast B.C. shale gas to market through the Alberta System. Subject to regulatory approvals, the approximate $310 million Horn River project is expected to be operational in second quarter 2012 with commitments for contracted natural gas rising to approximately 540 million cubic feet per day by 2014.

TCPL continues to receive additional requests for firm transportation service on both the Horn River and Groundbirch pipeline projects.

Foothills

In June 2010, TCPL reached an agreement to establish a cost of capital for Foothills which reflects a 9.70 per cent ROE on deemed common equity of 40 per cent for the years 2010 to 2012. Final tolls for 2010 have been approved by the NEB, effective July 1, 2010.

TQM

In June 2010, the NEB approved the final 2009 tolls for TQM as submitted which reflect a 6.4 per cent after-tax weighted average cost of capital return on rate base.

Alaska

The open season for the Alaska Pipeline Project will conclude on July 30, 2010. Throughout the 90 day open season, potential shippers have assessed the merits of the open season and the Alaska Pipeline Project has provided information to potential shippers in Alaska and Canada about the project's anticipated engineering design, commercial terms, estimated project costs and timelines.

Interested shippers will submit commercial bids prior to the close of the open season. It is typical with large, complex pipeline projects for bids from shippers to be conditional. The Alaska Pipeline Project will work with shippers to resolve any of these conditions within the project's control. Other key issues such as Alaska fiscal terms and natural gas resource access at Point Thomson, Alaska will need to be resolved between shippers and the State of Alaska. The Alaska Pipeline Project is expecting to complete these discussions and announce the results of the open season by the end of 2010.

Bison

In July 2010, TCPL received final approval to commence construction on a majority of the Bison natural gas pipeline project. Approvals for the remainder of the pipeline are expected in third quarter 2010. The Company commenced construction in July 2010 on the approximate US$600 million project which has an anticipated in-service date of fourth quarter 2010.

Great Lakes

On July 15, 2010, the Federal Energy Regulatory Commission (FERC) approved without modification the settlement stipulation and agreement reached among Great Lakes, active participants and the FERC trial staff. As approved, the stipulation and agreement will apply to all current and future shippers on Great Lakes' system. The Company does not expect the settlement to have a material effect on the results for Great Lakes given the current market environment.

Energy

Halton Hills

The $700 million Halton Hills generating station is in the final stages of commissioning and is expected to be in service in third quarter 2010, on time and on budget. Power from the 683 MW natural gasfired power plant near Halton Hills, Ontario will be sold to the OPA under a 20 year Clean Energy Supply contract.

Bécancour

In June 2010, Hydro-Québec notified TCPL it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2011. Under the original agreement signed in June 2009, Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TCPL will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Ravenswood

In September 2008, TCPL experienced a forced outage event related to the 972 MW Unit 30 at Ravenswood. The insurers of the business interruption and physical damage claim have denied coverage based on current claim information submitted for this event, however, they have invited TCPL to enter into settlement discussions. TCPL has filed a claim against the insurers to enforce its rights under the insurance policies. No amounts have been accrued for claims with respect to business interruption losses.

Sundance B

In second quarter 2010, Sundance B Unit 3 experienced an unplanned outage that the facility operator has asserted is a force majeure event. No information has been provided by the operator to date that supports the operator's claim that a force majeure event has occurred. Therefore, TCPL has recorded revenues under the PPA as though this event was a normal plant outage.

Oakville

TCPL continues to work through permitting issues with the Town of Oakville and the Province of Ontario on the 900 MW Oakville power generating station. A final Environmental Review Report is expected to be submitted to the Ontario Ministry of Environment in August 2010. As at June 30, 2010, TCPL had capitalized $62 million of costs related to the project.

Kibby Wind

Construction continues on the 66 MW second phase of the Kibby Wind project, which includes the installation of an additional 22 turbines. As at June 30, 2010, 12 of the wind turbine generators had been erected, ahead of schedule. The second phase is expected to be in service in fourth quarter 2010.

Power Transmission Line Projects

In May 2010, TCPL announced that it had concluded a successful open season for the proposed Zephyr power transmission (Zephyr) project and had received signed agreements for the full 3,000 megawatts (MW) of wind-generated capacity with renewable energy developers in Wyoming. Support from key markets and a positive regulatory environment are necessary before the significant siting and permitting activities required to construct the project will commence. The 1,600 kilometre (1,000 mile), 500 kilovolt, high voltage direct current line (HVDC) Zephyr project is expected to cost approximately US$3 billion and commercial operations are expected to commence in late 2015 or early 2016.

TCPL continues to pursue the proposed Chinook power transmission project, a 500 kilovolt, HVDC transmission line originating in Montana, and has extended its open season to December 16, 2010.

Share Information

As at July 27, 2010, TCPL had issued and outstanding 660 million common shares, four million Series U preferred shares and four million Series Y preferred shares.

Selected Quarterly Consolidated Financial Data[1]

(unaudited)	**2010**		2009				2008	
(millions of dollars except per share amounts)	**Second**	First	Fourth	Third	Second	First	Fourth	Third
Revenues	**1,923**	1,955	1,986	2,049	1,984	2,162	2,234	2,145
Net Income	**292**	301	384	343	316	336	274	383
Share Statistics								
Net income per share – Basic and Diluted	**$0.43**	$0.46	$0.58	$0.55	$0.52	$0.55	$0.47	$0.70

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been restated 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 are as follows:

- Second quarter 2010, Energy's EBIT included net unrealized gains of $9 million pre-tax ($6 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized gains of $6 million pre-tax ($4 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included $58 million of losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of working capital balances.

- First quarter 2010, Energy's EBIT included net unrealized losses of $28 million pre-tax ($17 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized losses of $21 million pre-tax ($15 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Fourth quarter 2009, Pipelines' EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TCPL's reduced ownership interest in PipeLines LP after PipeLines LP issued common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.

- 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 inventory in storage 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 inventory in storage 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, and the negative impact of Western Power's lower overall realized power prices.

- 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 inventory in storage 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 inventory in storage and natural gas forward purchase and sale contracts. Net Income included net unrealized losses of $57 million pre-tax ($39 million after tax) due to 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 2008 acquisition of Ravenswood. Net Income included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended June 30 **2010**	 2009	Six months ended June 30 **2010**	 2009
Revenues	**1,923**	1,984	**3,878**	4,146
Operating and Other Expenses				
Plant operating costs and other	**764**	792	**1,511**	1,607
Commodity purchases resold	**216**	182	**472**	411
Depreciation and amortization	**341**	345	**684**	691
	1,321	1,319	**2,667**	2,709
Financial Charges/(Income)				
Interest expense	**198**	264	**392**	565
Interest expense of joint ventures	**15**	16	**31**	30
Interest income and other	**18**	(34)	**(6)**	(56)
	231	246	**417**	539
Income before Income Taxes and Non-Controlling Interests	**371**	419	**794**	898
Income Taxes				
Current	**(198)**	37	**(118)**	91
Future	**260**	58	**277**	118
	62	95	**159**	209
Non-Controlling Interests				
Non-controlling interest in PipeLines LP	**17**	8	**39**	32
Non-controlling interest in Portland	**-**	-	**3**	5
	17	8	**42**	37
Net Income	**292**	316	**593**	652
Preferred Share Dividends	**(5)**	(5)	**(11)**	(11)
Net Income Applicable to Common Shares	**287**	311	**582**	641

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Cash Generated From Operations				
Net income	**292**	316	**593**	652
Depreciation and amortization	**341**	345	**684**	691
Future income taxes	**260**	58	**277**	118
Non-controlling interests	**17**	8	**42**	37
Employee future benefits funding in excess of expense	**(12)**	(23)	**(44)**	(57)
Other	**24**	(18)	**82**	5
	922	686	**1,634**	1,446
(Increase)/decrease in operating working capital	**(316)**	236	**(200)**	331
Net cash provided by operations	**606**	922	**1,434**	1,777
Investing Activities				
Capital expenditures	**(992)**	(1,263)	**(2,268)**	(2,386)
Acquisitions, net of cash acquired	**-**	(115)	**-**	(249)
Deferred amounts and other	**8**	(85)	**(208)**	(259)
Net cash used in investing activities	**(984)**	(1,463)	**(2,476)**	(2,894)
Financing Activities				
Dividends on common and preferred shares	**(280)**	(239)	**(546)**	(468)
Advances from parent	**15**	1,065	**398**	1,057
Distributions paid to non-controlling interests	**(23)**	(19)	**(44)**	(40)
Notes payable (repaid)/issued, net	**(441)**	233	**(9)**	(684)
Long-term debt issued, net of issue costs	**1,306**	-	**1,316**	3,060
Reduction of long-term debt	**(142)**	(18)	**(283)**	(500)
Long-term debt of joint ventures issued	**70**	92	**78**	108
Reduction of long-term debt of joint ventures	**(113)**	(33)	**(139)**	(56)
Common shares issued	**402**	52	**402**	126
Net cash provided by financing activities	**794**	1,133	**1,173**	2,603
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**33**	(60)	**16**	(34)
Increase in Cash and Cash Equivalents	**449**	532	**147**	1,452
Cash and Cash Equivalents Beginning of period	**677**	2,220	**979**	1,300
Cash and Cash Equivalents End of period	**1,126**	2,752	**1,126**	2,752
Supplementary Cash Flow Information				
Income taxes paid, net of refunds received	**39**	56	**43**	113
Interest paid, net of capitalized interest	**129**	274	**372**	537

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**June 30, 2010**	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	**1,126**	979
Accounts receivable	**1,102**	968
Due from TransCanada Corporation	**618**	845
Inventories	**454**	511
Other	**704**	701
	4,004	4,004
Plant, Property and Equipment	**35,101**	32,879
Goodwill	**3,807**	3,763
Regulatory Assets	**1,483**	1,524
Intangibles and Other Assets	**2,167**	2,500
	46,562	44,670
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**1,697**	1,687
Accounts payable	**2,105**	2,191
Accrued interest	**369**	380
Current portion of long-term debt	**587**	478
Current portion of long-term debt of joint ventures	**116**	212
	4,874	4,948
Due to TransCanada Corporation	**2,240**	2,069
Regulatory Liabilities	**313**	385
Deferred Amounts	**947**	743
Future Income Taxes	**3,043**	2,893
Long-Term Debt	**17,258**	16,186
Long-Term Debt of Joint Ventures	**795**	753
Junior Subordinated Notes	**1,050**	1,036
	30,520	29,013
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**714**	705
Non-controlling interest in Portland	**83**	80
	797	785
Shareholders' Equity	**15,245**	14,872
	46,562	44,670

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Net Income Applicable to Common Shares	**287**	311	**582**	641
Other Comprehensive Income/(Loss), Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**227**	(113)	**80**	(151)
Change in gains and losses on hedges of investments in foreign operations[2]	**(79)**	96	**(20)**	96
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**(44)**	37	**(121)**	64
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	**(3)**	(9)	**(2)**	(5)
Other Comprehensive Income/(Loss)	**101**	11	**(63)**	4
Comprehensive Income	**388**	322	**519**	645

(1) Net of income tax recovery of $45 million and $15 million for the three and six months ended June 30, 2010, respectively (2009 – expense of $6 million and nil, respectively).

(2) Net of income tax recovery of $34 million and $8 million for the three and six months ended June 30, 2010, respectively (2009 – expense of $48 million and $52 million, respectively).

(3) Net of income tax recovery of $27 million and $84 million for the three and six months ended June 30, 2010, respectively (2009 – expense of $19 million and $16 million, respectively).

(4) Net of income tax expense of $16 million and $17 million for the three and six months ended June 30, 2010, respectively (2009 – recovery of $1 million and nil, respectively).

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges	Total
Balance at December 31, 2009	**(592)**	**(40)**	**(632)**
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**80**	**-**	**80**
Change in gains and losses on hedges of investments in foreign operations[2]	**(20)**	**-**	**(20)**
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**-**	**(121)**	**(121)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][5]	**-**	**(2)**	**(2)**
Balance at June 30, 2010	**(532)**	**(163)**	**(695)**

Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(151)	-	(151)
Change in gains and losses on hedges of investments in foreign operations[2]	96	-	96
Changes in gains and losses on derivative instruments designated as cash flow hedges[3]	-	64	64
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	-	(5)	(5)
Balance at June 30, 2009	(434)	(34)	(468)

(1) Net of income tax recovery of $15 million for the six months ended June 30, 2010 (2009 - nil).
(2) Net of income tax recovery of $8 million for the six months ended June 30, 2010 (2009 - $52 million expense).
(3) Net of income tax recovery of $84 million for the six months ended June 30, 2010 (2009 - $16 million expense).
(4) Net of income tax expense of $17 million for the six months ended June 30, 2010 (2009 - nil).
(5) Losses related to cash flow hedges reported in Accumulated Other Comprehensive (Loss)/Income and expected to be reclassified to Net Income in the next 12 months are estimated to be $74 million ($45 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

See accompanying notes to the consolidated financial statements.

Consolidated Shareholders' Equity

(unaudited) *(millions of dollars)*	Six months ended June 30 **2010**	2009
Common Shares		
Balance at beginning of period	**10,649**	8,973
Proceeds from common shares issued	**402**	126
Balance at end of period	**11,051**	9,099
Preferred Shares		
Balance at beginning and end of period	**389**	389
Contributed Surplus		
Balance at beginning of period	**335**	284
Other	**4**	2
Balance at end of period	**339**	286
Retained Earnings		
Balance at beginning of period	**4,131**	3,789
Net income	**593**	652
Common share dividends	**(552)**	(494)
Preferred share dividends	**(11)**	(11)
Balance at end of period	**4,161**	3,936
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	**(632)**	(472)
Other comprehensive (loss)/income	**(63)**	4
Balance at end of period	**(695)**	(468)
	3,466	3,468
Total Shareholders' Equity	**15,245**	13,242

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, 2009. 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 2009 audited Consolidated Financial Statements included in TCPL's 2009 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 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. 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 2009 Annual Report. Future accounting changes that will impact the Company are as follows:

Future Accounting Changes

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) previously 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. As an SEC registrant, TCPL has the option to prepare and file its consolidated financial statements using U.S. GAAP. Previously, TCPL disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. Prior to the developments noted below, the Company's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

Rate-Regulated Accounting

In accordance with Canadian GAAP, TCPL currently follows specific accounting policies unique to a rate-regulated business which are consistent with rate-regulated accounting (RRA) standards in U.S. GAAP. Under RRA, the timing of recognition of certain expenses and revenues may differ from that otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing differences are recorded as regulatory assets and regulatory liabilities on TCPL's consolidated balance sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the applicable regulatory authorities. As at June 30, 2010, TCPL reported $1.7 billion of regulatory assets and $0.4 billion of regulatory liabilities using RRA in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities" which proposed a form of RRA under IFRS. To date, the IASB has not approved an RRA standard and TCPL does not expect a final RRA standard under IFRS, to be effective for 2011. As a result, in July 2010, the CICA's AcSB issued an Exposure Draft applicable to Canadian publicly accountable enterprises that use RRA, which, if approved, would allow these entities to defer the adoption of IFRS for two years. A final decision is expected by the AcSB before the end of 2010. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, if the AcSB Exposure Draft is approved, TCPL expects to defer its adoption of IFRS accordingly, and continue to prepare its consolidated financial statements in accordance with Canadian GAAP to maintain the use of RRA. During the deferral period, TCPL will continue to actively monitor IASB developments with respect to RRA. If the AcSB Exposure Draft is not approved or the IASB has not approved an RRA standard within the two year deferral period that allows the Company's rate-regulated activities to be appropriately reflected in its consolidated financial statements, TCPL expects to re-evaluate its decision to adopt IFRS and reconsider the adoption of U.S. GAAP.

As a result of these developments related to RRA under IFRS, TCPL cannot reasonably quantify the full impact that adopting IFRS would have on its financial position and future results if it proceeded with adopting IFRS. The Company will continue to monitor non-RRA IFRS developments and their potential impact on TCPL.

3. Segmented Information

Three months ended June 30 *(unaudited)(millions of dollars)*	Pipelines 2010	Pipelines 2009	Energy[1] 2010	Energy[1] 2009	Corporate 2010	Corporate 2009	Total 2010	Total 2009
Revenues	**1,061**	1,142	**862**	842	**-**	-	**1,923**	1,984
Plant operating costs and other	**(365)**	(395)	**(377)**	(366)	**(22)**	(31)	**(764)**	(792)
Commodity purchases resold	**-**	-	**(216)**	(182)	**-**	-	**(216)**	(182)
Depreciation and amortization	**(251)**	(258)	**(90)**	(87)	**-**	-	**(341)**	(345)
	445	489	**179**	207	**(22)**	(31)	**602**	665
Interest expense							**(198)**	(264)
Interest expense of joint ventures							**(15)**	(16)
Interest income and other							**(18)**	34
Income taxes							**(62)**	(95)
Non-controlling interests							**(17)**	(8)
Net Income							**292**	316
Preferred share dividends							**(5)**	(5)
Net Income Applicable to Common Shares							**287**	311

Six months ended June 30 *(unaudited)(millions of dollars)*	Pipelines 2010	Pipelines 2009	Energy[1] 2010	Energy[1] 2009	Corporate 2010	Corporate 2009	Total 2010	Total 2009
Revenues	**2,190**	2,406	**1,688**	1,740	**-**	-	**3,878**	4,146
Plant operating costs and other	**(726)**	(788)	**(737)**	(758)	**(48)**	(61)	**(1,511)**	(1,607)
Commodity purchases resold	**-**	-	**(472)**	(411)	**-**	-	**(472)**	(411)
Depreciation and amortization	**(504)**	(518)	**(180)**	(173)	**-**	-	**(684)**	(691)
	960	1,100	**299**	398	**(48)**	(61)	**1,211**	1,437
Interest expense							**(392)**	(565)
Interest expense of joint ventures							**(31)**	(30)
Interest income and other							**6**	56
Income taxes							**(159)**	(209)
Non-controlling interests							**(42)**	(37)
Net Income							**593**	652
Preferred share dividends							**(11)**	(11)
Net Income Applicable to Common Shares							**582**	641

(1) Effective January 1, 2010, the Company records in Revenues on a net basis, realized and unrealized gains and losses on derivatives used to purchase and sell power, natural gas and fuel oil in order to manage Energy's assets. Comparative figures for 2009 reflect amounts reclassified from Commodity Purchases Resold to Revenues.

Total Assets

(unaudited) *(millions of dollars)*	June 30, 2010	December 31, 2009
Pipelines	**31,005**	29,508
Energy	**12,798**	12,477
Corporate	**2,759**	2,685
	46,562	44,670

4. Long-Term Debt

In June 2010, TCPL issued senior notes of US$500 million and US$750 million maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US$4.0 billion debt shelf prospectus filed in December 2009.

In the three and six months ended June 30, 2010, the Company capitalized interest related to capital projects of $143 million and $277 million, respectively (2009 - $63 million and $117 million).

5. Share Capital

In the three and six months ended June 30, 2010, TCPL issued 10.7 million common shares (2009 – 1.7 million and 3.9 million common shares, respectively) to TransCanada Corporation (TransCanada) for proceeds of $402 million (2009 – $52 million and $126 million).

6. Financial Instruments and Risk Management

TCPL continues to manage and monitor its exposure to counterparty credit, liquidity and market 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 of accounts receivable, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At June 30, 2010, there were no significant amounts past due or impaired.

At June 30, 2010, the Company had a credit risk concentration of $348 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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.

Natural Gas Inventory

At June 30, 2010, 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 $51 million (December 31, 2009 - $73 million). The change in fair value of proprietary natural gas inventory in storage in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of $4 million and net pre-tax unrealized losses of $20 million, respectively, which were recorded as an increase and a decrease, respectively, to Revenues and Inventories (2009 - losses of $6 million and $29 million). The change in fair value of natural gas forward purchase and sale contracts in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of $2 million and $5 million, respectively (2009 – losses of $1 million and gains of $9 million), which were included in Revenues.

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 $7 million at June 30, 2010 (December 31, 2009 – $12 million). The decrease from December 31, 2009 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At June 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.4 billion (US$8.8 billion) and a fair value of $9.7 billion (US$9.2 billion). At June 30, 2010, $20 million (December 31, 2009 - $96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional principal amounts for the derivatives designated as a net investment hedge were as follows:

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**June 30, 2010** **Fair Value[1]**	 **Notional or Principal Amount**	December 31, 2009 Fair Value[1]	 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**37**	**U.S. 2,100**	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	**(17)**	**U.S. 550**	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	**-**	**-**	1	U.S. 100
	20	**U.S. 2,650**	96	U.S. 2,715

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

	June 30, 2010		December 31, 2009	
(unaudited) *(millions of dollars)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets(1)				
Cash and cash equivalents	**1,126**	**1,126**	979	979
Accounts receivable and other(2)(3)	**1,343**	**1,384**	1,433	1,484
Due from TransCanada Corporation	**618**	**618**	845	845
Available-for-sale assets(2)	**20**	**20**	23	23
	3,107	**3,148**	3,280	3,331
Financial Liabilities(1)(3)				
Notes payable	**1,697**	**1,697**	1,687	1,687
Accounts payable and deferred amounts(4)	**1,291**	**1,291**	1,532	1,532
Due to TransCanada Corporation	**2,240**	**2,240**	2,069	2,069
Accrued interest	**369**	**369**	380	380
Long-term debt	**17,845**	**21,125**	16,664	19,377
Junior subordinated notes	**1,050**	**1,072**	1,036	976
Long-term debt of joint ventures	**911**	**1,011**	965	1,025
	25,403	**28,805**	24,333	27,046

(1) Consolidated Net Income in 2010 included gains of $9 million (2009 – $8 million) for fair value adjustments related to interest rate swap agreements on US$150 million (2009 – US$300 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At June 30, 2010, the Consolidated Balance Sheet included financial assets of $868 million (December 31, 2009 – $968 million) in Accounts Receivable, $42 million in Other Current Assets (December 31, 2009 – nil) and $453 million (December 31, 2009 - $488 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for certain long-term debt which is recorded at fair value.

(4) At June 30, 2010, the Consolidated Balance Sheet included financial liabilities of $1,262 million (December 31, 2009 – $1,507 million) in Accounts Payable and $29 million (December 31, 2009 - $25 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

June 30, 2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$210**	**$146**	**-**	**$29**
Liabilities	**$(158)**	**$(145)**	**$(20)**	**$(90)**
Notional Values				
Volumes[3]				
Purchases	**13,165**	**117**	**-**	**-**
Sales	**14,285**	**89**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**960**
U.S. dollars	**-**	**-**	**U.S. 1,143**	**U.S. 1,525**
Cross-currency	**-**	**-**	**47/U.S. 37**	**-**
Net unrealized (losses)/gains in the period[4]				
Three months ended June 30, 2010	**$(10)**	**$3**	**$(11)**	**$(13)**
Six months ended June 30, 2010	**$(26)**	**$5**	**$(11)**	**$(17)**
Net realized gains/(losses) in the period[4]				
Three months ended June 30, 2010	**$15**	**$(17)**	**$(6)**	**$(6)**
Six months ended June 30, 2010	**$37**	**$(29)**	**$2**	**$(10)**
Maturity dates	**2010-2015**	**2010-2014**	**2010-2012**	**2010-2018**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$124**	**$1**	**-**	**$9**
Liabilities	**$(237)**	**$(54)**	**$(37)**	**$(116)**
Notional Values				
Volumes[3]				
Purchases	**14,792**	**63**	**-**	**-**
Sales	**15,209**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**U.S. 120**	**U.S. 1,975**
Cross-currency	**-**	**-**	**136/U.S. 100**	**-**
Net realized losses in the period[4]				
Three months ended June 30, 2010	**$(36)**	**$(6)**	**-**	**$(9)**
Six months ended June 30, 2010	**$(43)**	**$(9)**	**-**	**$(19)**
Maturity dates	**2010-2015**	**2010-2012**	**2010- 2014**	**2011-2020**

(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 and natural gas derivatives are in GWh and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on power and natural gas 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 $9 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and six months ended June 30, 2010 were $1 million and $2 million, respectively, and were included in Interest Expense. In second quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three and six months ended June 30, 2010 included gains of $7 million and losses of $1 million, respectively, for changes in the 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 for the three and six months ended June 30, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2009
(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][2]					
Assets	$150	$107	$5	-	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values[2]					
Volumes[3]					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/U.S. 157	-
Net unrealized (losses)/gains in the period[4]					
Three months ended June 30, 2009	$(2)	$10	$(5)	$1	$27
Six months ended June 30, 2009	$19	$(25)	$2	$2	$27
Net realized gains/(losses) in the period[4]					
Three months ended June 30, 2009	$20	$(39)	$2	$11	$(5)
Six months ended June 30, 2009	$30	$(13)	$(1)	$17	$(9)
Maturity dates[2]	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[1][2]					
Assets	$175	$2	-	-	$15
Liabilities	$(148)	$(22)	-	$(43)	$(50)
Notional Values[2]					
Volumes[3]					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period[4]					
Three months ended June 30, 2009	$52	$(10)	-	-	$(10)
Six months ended June 30, 2009	$78	$(20)	-	-	$(17)
Maturity dates[2]	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.
(2) As at December 31, 2009.
(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.
(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to

Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million at December 31, 2009. Net realized gains on fair value hedges for the three and six months ended June 30, 2009 were $1 million and $2 million, respectively, and were included in Interest Expense. In second quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three and six months ended June 30, 2009 included losses of $4 million and gains of $1 million, respectively, for changes in the 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 for the three and six months ended June 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**June 30, 2010**	December 31, 2009
Current		
Other current assets	**311**	315
Accounts payable	**(406)**	(340)
Long-term		
Intangibles and other assets	**228**	260
Deferred amounts	**(451)**	(272)

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. Fair value of assets and liabilities included in Level I is determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level II include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. Level III valuations are based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets and the fair value of guarantees are included in this category. Long-dated commodity prices are derived with a third-party modelling tool that uses market fundamentals to derive long-term prices. The fair value of guarantees is estimated by discounting the cash flows that would be incurred if letters of credit were used in place of the guarantees.

Financial assets and liabilities measured at fair value as of June 30, 2010, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in second quarter 2010.

(unaudited) *(millions of dollars, pre-tax)*	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total
Natural Gas Inventory	-	51	-	51
Derivative Financial Instruments:				
Assets	90	480	17	587
Liabilities	(187)	(696)	(22)	(905)
Available-for-sale assets	20	-	-	20
Guarantee Liabilities[1]	-	-	(9)	(9)
	(77)	(165)	(14)	(256)

(1) The fair value of guarantees is included in Deferred Amounts.

The following table presents the net change in financial assets and liabilities measured at fair value and included in the Level III fair value category:

(unaudited) *(millions of dollars, pre-tax)*	Derivatives[1]	Guarantees[2]	Total
Balance at December 31, 2009	(2)	(9)	(11)
New contracts[3]	(10)	-	(10)
Settlements	(2)	-	(2)
Transfers out of Level III[4]	(15)	-	(15)
Change in unrealized gains recorded in Net Income	14	-	14
Change in unrealized gains recorded in Other Comprehensive Income	10	-	10
Balance at June 30, 2010	(5)	(9)	(14)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) The fair value of guarantees is included in Deferred Amounts. No amounts were recognized in Net Income for the periods presented.
(3) The total amount of net gains included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date was $1 million and nil for the three and six months ended June 30, 2010, respectively.
(4) As contracts near maturity, they are transferred out of Level III to Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $28 million decrease or increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at June 30, 2010.

A 100 basis points increase or decrease in the letter of credit rate, with all other variables held constant, would result in a $3 million increase or decrease, respectively, in the fair value of guarantee liabilities outstanding as at June 30, 2010. Similarly, the effect of a 100 basis points increase or decrease in the risk-free interest rate, which is a component of the discount rate, on the fair value of guarantee liabilities outstanding as at June 30, 2010 would result in a $1 million decrease or increase, respectively, in the liability.

7. Employee Future Benefits

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

Three months ended June 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009
Current service cost	**13**	12	**1**	1
Interest cost	**22**	22	**2**	2
Expected return on plan assets	**(27)**	(26)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**2**	1	**1**	1
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**11**	10	**4**	4

Six months ended June 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009
Current service cost	**25**	23	**1**	1
Interest cost	**45**	45	**4**	4
Expected return on plan assets	**(54)**	(51)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**4**	2	**1**	1
Amortization of past service costs	**2**	2	**-**	-
Net benefit cost recognized	**22**	21	**6**	6

8. Commitments and Contingencies

At June 30, 2010, TCPL had entered into agreements totalling approximately $530 million to purchase construction materials and services for the Bison natural gas pipeline and Cartier Wind power projects.

Amounts received under the Bruce B floor price mechanism in any year are subject to repayment if average spot prices exceed the floor price. With respect to 2010, TCPL currently expects average spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenue in the first six months of 2010 are expected to be repaid.

9. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

(unaudited) *(millions of dollars)*	Maturity Dates	**2010** **Outstanding June 30**	**2010** **Interest Rate**	2009 Outstanding December 31	2009 Interest Rate
Discount Notes	2010	**2,118**	**1.1 %**	1,959	0.6 %
Credit Facility		**(1,500)**	**2.3 %**	(1,114)	2.3 %
		618		845	

The following amounts are included in Due to TransCanada Corporation:

(unaudited) *(millions of dollars)*	Maturity Dates	**2010** **Outstanding June 30**	**2010** **Interest Rate**	2009 Outstanding December 31	2009 Interest Rate
Credit Facility	2012	**2,240**	**1.8 %**	2,069	1.3 %

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/ Terry Hook at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: Cecily Dobson/Terry Cunha (403) 920-7859 or (800) 608-7859.

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