

Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated November 2, 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 nine months ended September 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 September 30 (unaudited)(millions of dollars)	Pipelines		Energy		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Comparable EBITDA⁽¹⁾	714	730	311	292	(18)	(28)	1,007	994
Depreciation and amortization	(232)	(255)	(94)	(88)	-	-	(326)	(343)
Comparable EBIT⁽¹⁾	482	475	217	204	(18)	(28)	681	651
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	-	-	(3)	-	-	-	(3)	-
Fair value adjustments of natural gas inventory in storage and forward contracts	-	-	7	14	-	-	7	14
EBIT⁽¹⁾	482	475	221	218	(18)	(28)	685	665
Interest expense							(173)	(228)
Interest expense of joint ventures							(13)	(17)
Interest income and other							27	41
Income taxes							(116)	(101)
Non-controlling interests							(23)	(17)
Net Income							387	343
Preferred share dividends							(6)	(6)
Net Income Applicable to Common Shares							381	337
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							2	-
Fair value adjustments of natural gas inventory in storage and forward contracts							(5)	(10)
Comparable Earnings⁽¹⁾							378	327

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

For the nine months ended September 30 (unaudited)(millions of dollars)	Pipelines		Energy		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Comparable EBITDA⁽¹⁾	2,178	2,348	824	883	(66)	(89)	2,936	3,142
Depreciation and amortization	(736)	(773)	(274)	(261)	-	-	(1,010)	(1,034)
Comparable EBIT⁽¹⁾	1,442	1,575	550	622	(66)	(89)	1,926	2,108
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	-	-	(22)	-	-	-	(22)	-
Fair value adjustments of natural gas inventory in storage and forward contracts	-	-	(8)	(6)	-	-	(8)	(6)
EBIT⁽¹⁾	1,442	1,575	520	616	(66)	(89)	1,896	2,102
Interest expense							(565)	(793)
Interest expense of joint ventures							(44)	(47)
Interest income and other							33	97
Income taxes							(275)	(310)
Non-controlling interests							(65)	(54)
Net Income							980	995
Preferred share dividends							(17)	(17)
Net Income Applicable to Common Shares							963	978
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							13	-
Fair value adjustments of natural gas inventory in storage and forward contracts							6	4
Comparable Earnings⁽¹⁾							982	982

⁽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 third quarter 2010 was \$387 million and Net Income Applicable to Common Shares was \$381 million compared to \$343 and \$337 million, respectively, in third quarter 2009. The \$44 million increase in Net Income Applicable to Common Shares reflected:

- increased EBIT from Pipelines primarily due to the positive impact of recognizing the 2010 - 2012 Alberta System Revenue Requirement Settlement (Alberta System Settlement) from its effective date of January 1, 2010, lower depreciation and reduced operating, maintenance and administration (OM&A) costs, partially offset by the negative impact of a weaker U.S. dollar;
- increased EBIT from Energy primarily due to higher realized prices, volumes and capacity revenues for U.S. Power, and higher sales volumes at Bruce A, partially offset by lower realized power prices for Western Power and Bruce B, and decreased proprietary and third party storage revenues for Natural Gas Storage;
- decreased EBIT losses from Corporate primarily due to lower support and other corporate costs;
- decreased Interest Expense primarily due to increased capitalized interest and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by incremental interest on new debt issues in 2010;
- a negative impact on Interest Income and Other from lower gains in 2010 compared to 2009 on the translation of U.S. dollar-denominated working capital balances; and
- increased Income Taxes due to higher pre-tax earnings.

Comparable Earnings in third quarter 2010 were \$378 million compared to \$327 million for the same period in 2009. Comparable Earnings in third quarter 2010 excluded \$2 million after tax (\$3 million pre-tax) of net unrealized losses resulting from changes in the fair value of U.S. Power derivative contracts. Effective January 1, 2010, these unrealized gains and losses 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 excluded from the computation of Comparable Earnings. Comparable Earnings in third quarter 2010 and 2009 also excluded net unrealized gains of \$5 million after tax (\$7 million pre-tax) and \$10 million after tax (\$14 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 U.S. Energy EBIT is partially 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 was 1.04 for each of the three and nine month periods ended September 30, 2010 (2009 - 1.10 and 1.17, respectively).

TCPL's Net Income in the first nine months of 2010 was \$980 million and Net Income Applicable to Common Shares was \$963 million compared to \$995 and \$978 million, respectively for the same period in 2009. The \$15 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 reduced revenues from certain U.S. pipelines, partially offset by the positive impact of recognizing the Alberta System Settlement, lower depreciation and reduced OM&A costs;
- decreased EBIT from Energy primarily due to lower overall realized power prices at Western Power, reduced volumes and higher operating costs at Bruce A, lower realized prices partially offset by higher volumes at Bruce B, reduced earnings at Bécancour and decreased proprietary and third party storage revenues for Natural Gas Storage, partially offset by increased volumes and capacity revenue from U.S. Power, and incremental earnings from Portlands Energy and Halton Hills, which went into service in April 2009 and September 2010, respectively;
- decreased EBIT losses from Corporate primarily due to lower support and other corporate costs;
- 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 incremental interest expense on new debt issues in 2010 and by higher losses in 2010 compared to 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 lower gains in 2010 compared to 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and the negative impact from the translation of U.S. dollar-denominated working capital balances; and
- decreased Income Taxes due to the net positive impact from income tax rate differentials, other income tax adjustments and lower pre-tax earnings.

Comparable Earnings in the first nine months of 2010 were \$982 million, consistent with the same period in 2009. Comparable Earnings for the first nine months of 2010 excluded \$13 million of after tax (\$22 million pre-tax) net unrealized losses resulting from changes in the fair value of U.S. Power derivative contracts. Comparative amounts in 2009 were not excluded from the computation of Comparable Earnings. Comparable Earnings in the first nine months of 2010 and 2009 also excluded

net unrealized losses of \$6 million after tax (\$8 million pre-tax) and \$4 million after tax (\$6 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 nine months in 2010 are discussed further in the Pipelines and Energy sections of this MD&A.

Pipelines

Pipelines' Comparable EBIT and EBIT were \$482 million and \$1.4 billion in the three and nine month periods ended September 30, 2010, respectively, compared to \$475 million and \$1.6 billion for the same periods in 2009.

Pipelines Results

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Canadian Pipelines				
Canadian Mainline	257	279	785	851
Alberta System	197	190	548	535
Foothills	34	32	102	100
Other (TQM, Ventures LP)	12	13	39	44
Canadian Pipelines Comparable EBITDA⁽¹⁾	500	514	1,474	1,530
U.S. Pipelines				
ANR	67	57	248	263
GTN ⁽²⁾	44	42	130	152
Great Lakes	27	31	86	108
PipeLines LP ⁽²⁾⁽³⁾	28	29	76	79
Iroquois	16	18	53	62
Portland ⁽⁴⁾	1	2	12	18
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	10	18	35	46
General, administrative and support costs ⁽⁵⁾	(16)	(11)	(25)	(18)
Non-controlling interests ⁽⁶⁾	45	40	130	134
U.S. Pipelines Comparable EBITDA⁽¹⁾	222	226	745	844
Business Development Comparable EBITDA⁽¹⁾	(8)	(10)	(41)	(26)
Pipelines Comparable EBITDA⁽¹⁾	714	730	2,178	2,348
Depreciation and amortization	(232)	(255)	(736)	(773)
Pipelines Comparable EBIT and EBIT⁽¹⁾	482	475	1,442	1,575

(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 three and nine months ended September 30, 2010 (first six months of 2009 - 32.1 per cent; three months ended September 30, 2009 - 42.6 per cent).

(4) Portland's results reflect TCPL's 61.7 per cent ownership interest.

(5) Represents general and administrative costs associated with certain of the Company'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

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Canadian Mainline	66	68	196	201
Alberta System	70	44	145	123
Foothills	7	6	20	18

Canadian Pipelines

Canadian Mainline's net income for the three and nine months ended September 30, 2010 decreased \$2 million and \$5 million, respectively, compared to the same periods in 2009 primarily due to 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 nine months ended September 30, 2010 of \$257 million and \$785 million, respectively, decreased \$22 million and \$66 million, respectively, compared to the same periods in 2009 primarily due to lower revenues as a result of lower income taxes and financial charges 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 debt that matured in 2009 and early 2010.

The Alberta System's net income was \$70 million in third quarter 2010 and \$145 million for the first nine months of 2010 compared to \$44 million and \$123 million for the same periods in 2009. Net income in third quarter 2010 increased \$26 million compared to 2009 and reflects the regulatory approval and recognition of the Alberta System Settlement with stakeholders, which includes a 9.70 per cent ROE on deemed common equity of 40 per cent, effective January 1, 2010. The positive impact of the higher ROE and investment base was partially offset by lower incentive earnings compared to 2009.

The Alberta System's Comparable EBITDA was \$197 million in third quarter 2010 and \$548 million for the first nine months of 2010 compared to \$190 million and \$535 million for the same periods in 2009. These increases were due to higher revenues associated with the equity return included in the Alberta System Settlement and an increased average investment base, partially offset by lower depreciation and financial charges recovered on a flow-through basis under the Alberta System Settlement and lower incentive earnings compared to 2009.

Comparable EBITDA from Other Canadian Pipelines was \$12 million in third quarter 2010 and \$39 million for the first nine months of 2010, respectively, compared to \$13 million and \$44 million for the same periods in 2009. The decrease in the nine months ended September 30, 2010 was primarily due to an adjustment recorded in first quarter 2009 for an NEB decision to increase TQM's allowed rate of return on capital for 2008 and 2007.

U.S. Pipelines

ANR's Comparable EBITDA in the three and nine months ended September 30, 2010 was \$67 million and \$248 million, respectively, compared to \$57 million and \$263 million for the same periods in 2009. The increase in third quarter 2010 compared to third quarter 2009 was primarily due to lower OM&A costs, partially offset by the impact of a weaker U.S. dollar. For the nine months ended September 30, 2010, the decrease was primarily due to the negative impact of a weaker U.S. dollar, partially offset by lower OM&A costs.

GTN's Comparable EBITDA for the nine months ended September 30, 2010 decreased \$22 million from the same period 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 lower OM&A costs in 2010.

Comparable EBITDA for the remainder of the U.S. Pipelines was \$111 million and \$367 million for the three and nine months ended September 30, 2010, respectively, compared to \$127 million and \$429 million for the same periods in 2009. The decreases were primarily due to the negative impact of a weaker U.S. dollar, lower revenues from Great Lakes and higher general, administrative and support costs primarily related to the startup of Keystone. These decreases were partially offset by the positive impact on PipeLines LP's earnings as a result of its acquisition of North Baja in July 2009 and higher revenue from Northern Border.

Business Development

Pipelines' Business Development Comparable EBITDA decreased \$15 million in the nine months ended September 30, 2010 compared to the same period in 2009. EBITDA for the nine months ended September 30, 2010 reflects increased expenses 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 is reimbursing up to 50 per cent of the eligible costs incurred prior to the close of the first binding open season on July 30, 2010. Commencing July 31, 2010, the State began reimbursing 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.

Depreciation

Pipelines' depreciation decreased \$23 million and \$37 million for the three and nine months ended September 30, 2010, respectively, primarily due to reduced depreciation resulting from Great Lakes' rate settlement in 2010 and the impact of a weaker U.S. dollar. The decrease in third quarter 2010 was also due to the Alberta System Settlement.

Operating Statistics

Nine months ended September 30 (<i>unaudited</i>)	Canadian Mainline ⁽¹⁾		Alberta System ⁽²⁾		Foothills		ANR ⁽³⁾		GTN ⁽³⁾	
	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009
Average investment base (\$millions)	6,518	6,549	4,986	4,724	661	711	n/a	n/a	n/a	n/a
Delivery volumes (Bcf)										
Total	1,191	1,561	2,535	2,652	1,054	901	1,171	1,199	598	578
Average per day	4.4	5.7	9.3	9.7	3.9	3.3	4.3	4.4	2.2	2.1

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the nine months ended September 30, 2010 were 927 billion cubic feet (Bcf) (2009 – 1,234 Bcf); average per day was 3.4 Bcf (2009 – 4.5 Bcf).

(2) Field receipt volumes for the Alberta System for the nine months ended September 30, 2010 were 2,619 Bcf (2009 – 2,734 Bcf); average per day was 9.6 Bcf (2009 – 10.0 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 September 30, 2010, TCPL had advanced \$145 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 is expected to release its decision on the project's application for a certificate of public convenience and necessity by December 2010. Project timing thereafter 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 \$217 million in third quarter 2010 compared to \$204 million in third quarter 2009. Comparable EBIT in third quarter 2010 excluded net unrealized losses of \$3 million resulting from changes in the fair value of U.S. Power derivative contracts. Comparable EBIT in third quarter 2010 and 2009 also excluded net unrealized gains of \$7 million and \$14 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 \$550 million in the first nine months of 2010 compared to \$622 million in the same nine months of 2009. Comparable EBIT excluded net unrealized losses of \$22 million resulting from changes in the fair value of U.S. Power derivative contracts. Comparable EBIT in the first nine months of 2010 and 2009 also excluded net unrealized losses of \$8 million and \$6 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

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Canadian Power				
Western Power	45	66	172	218
Eastern Power ⁽¹⁾	56	52	154	164
Bruce Power	89	81	199	282
General, administrative and support costs	(14)	(9)	(29)	(28)
Canadian Power Comparable EBITDA⁽²⁾	176	190	496	636
U.S. Power				
Northeast Power ⁽³⁾	123	80	279	198
General, administrative and support costs	(7)	(12)	(25)	(35)
U.S. Power Comparable EBITDA⁽²⁾	116	68	254	163
Natural Gas Storage				
Alberta Storage	28	47	101	122
General, administrative and support costs	(2)	(2)	(6)	(7)
Natural Gas Storage Comparable EBITDA⁽²⁾	26	45	95	115
Business Development Comparable EBITDA⁽²⁾	(7)	(11)	(21)	(31)
Energy Comparable EBITDA⁽²⁾	311	292	824	883
Depreciation and amortization	(94)	(88)	(274)	(261)
Energy Comparable EBIT⁽²⁾	217	204	550	622
Specific items:				
Fair value adjustments of U.S. Power derivative contracts	(3)	-	(22)	-
Fair value adjustments of natural gas inventory in storage and forward contracts	7	14	(8)	(6)
Energy EBIT⁽²⁾	221	218	520	616

(1) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.

(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⁾**

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Revenues				
Western power	168	196	534	585
Eastern power	85	69	217	209
Other ⁽³⁾	27	19	64	61
	280	284	815	855
Commodity Purchases Resold				
Western power	(109)	(120)	(314)	(327)
Other ⁽³⁾⁽⁴⁾	(12)	(4)	(24)	(19)
	(121)	(124)	(338)	(346)
Plant operating costs and other	(58)	(42)	(151)	(129)
General, administrative and support costs	(14)	(9)	(29)	(28)
Other income	-	-	-	2
Comparable EBITDA⁽¹⁾	87	109	297	354

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

(2) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.

(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⁾

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Sales Volumes (GWh)				
Supply				
Generation				
Western Power	572	541	1,751	1,718
Eastern Power	661	305	1,485	1,081
Purchased				
Sundance A & B and Sheerness PPAs	2,641	2,560	7,755	7,725
Other purchases	89	113	311	420
	3,963	3,519	11,302	10,944
Sales				
Contracted				
Western Power	2,526	2,514	7,368	7,164
Eastern Power	660	307	1,500	1,117
Spot				
Western Power	777	698	2,434	2,663
	3,963	3,519	11,302	10,944
Plant Availability				
Western Power ⁽²⁾	94%	90%	94%	92%
Eastern Power	98%	97%	97%	97%

(1) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.

(2) Excludes facilities that provide power to TCPL under PPAs.

Western Power's Comparable EBITDA of \$45 million and Power Revenues of \$168 million in third quarter 2010 decreased \$21 million and \$28 million, respectively, compared to the same period in

2009, primarily due to lower overall realized power prices. Average spot market power prices in Alberta decreased 28 per cent to \$36 per megawatt hour (MWh) in third quarter 2010 compared to \$50 per MWh in third quarter 2009. Spot market sales represented 24 per cent of Western Power's total sales in third quarter 2010.

Western Power's Comparable EBITDA of \$172 million and Power Revenues of \$534 million in the first nine months of 2010 decreased \$46 million and \$51 million, respectively, compared to the same period in 2009, primarily due to lower overall realized power prices.

Eastern Power's Comparable EBITDA of \$56 million and Power Revenues of \$85 million in third quarter 2010 increased \$4 million and \$16 million, respectively, compared to the same period in 2009. These increases were primarily due to incremental earnings from Halton Hills, which went into service under a 20 year power purchase arrangement (PPA) in September 2010, partially offset by lower contracted earnings from Bécancour. Results from Bécancour are consistent with the expected contracted earnings according to the original electricity supply contract with Hydro-Québec.

Eastern Power's Comparable EBITDA of \$154 million in the first nine months of 2010 decreased \$10 million, compared to the same period in 2009, primarily due to lower contracted earnings from Bécancour and unfavourable wind conditions at Cartier Wind, partially offset by incremental earnings from Portlands Energy and Halton Hills, which went into service in April 2009 and September 2010, respectively.

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 76 per cent of Western Power sales volumes were sold under contract in third quarter 2010, compared to 78 per cent in third quarter 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at September 30, 2010, Western Power had entered into fixed-price power sales contracts to sell approximately 2,400 gigawatt hours (GWh) for the remainder of 2010 and 7,300 GWh for 2011.

Eastern Power is focused on selling power under long-term contracts. In third 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 the remainder of 2010 and 2011.

Bruce Power Results

(TCPL's proportionate share) (unaudited) (millions of dollars unless otherwise indicated)	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Revenues ⁽¹⁾	212	224	634	685
Operating Expenses	(123)	(143)	(435)	(403)
Comparable EBITDA⁽²⁾	89	81	199	282
Bruce A Comparable EBITDA⁽²⁾	35	(11)	58	77
Bruce B Comparable EBITDA⁽²⁾	54	92	141	205
Comparable EBITDA⁽²⁾	89	81	199	282
Bruce Power – Other Information				
Plant availability				
Bruce A	92%	71%	77%	89%
Bruce B	88%	97%	90%	90%
Combined Bruce Power	89%	89%	86%	90%
Planned outage days				
Bruce A	-	46	60	46
Bruce B	7	-	54	45
Unplanned outage days				
Bruce A	7	3	55	8
Bruce B	28	3	34	44
Sales volumes (GWh)				
Bruce A	1,446	1,099	3,556	4,157
Bruce B	2,003	1,950	6,102	5,751
	3,449	3,049	9,658	9,908
Results per MWh				
Bruce A power revenues	\$65	\$64	\$65	\$64
Bruce B power revenues ⁽³⁾	\$57	\$66	\$58	\$64
Combined Bruce Power revenues	\$60	\$66	\$60	\$64
Percentage of Bruce B output sold to spot market ⁽⁴⁾				
	82%	49%	78%	42%

(1) Revenues include Bruce A's fuel cost recoveries of \$7 million and \$21 million for the three and nine months ended September 30, 2010, respectively (2009 – \$7 million and \$28 million, respectively). Revenues also include Bruce B unrealized losses of \$4 million and \$5 million as a result of changes in the fair value of power derivatives for the three and nine months ended September 30, 2010, respectively (2009 – gains of \$2 million and \$4 million, respectively).

(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 increased \$8 million to \$89 million in third quarter 2010 compared to \$81 million in third quarter 2009.

TCPL's proportionate share of Bruce A's Comparable EBITDA increased \$46 million to \$35 million in third quarter 2010 compared to losses of \$11 million in third quarter 2009 as a result of increased volumes and lower operating costs due to decreased outage days. Bruce A's plant availability in third quarter 2010 was 92 per cent with seven outage days compared to an availability of 71 per cent and 49 outage days in the same period in 2009.

TCPL's proportionate share of Bruce B's Comparable EBITDA decreased \$38 million to \$54 million in third quarter 2010 compared to \$92 million in third quarter 2009 primarily due to lower realized prices resulting from the expiration of fixed-price contracts at higher prices. Bruce B's volumes increased in third quarter 2010 compared to the same period in 2009 as a result of fewer surplus baseload generation (SBG) derates in 2010 as required by the Independent Electricity System Operator, partially offset by lower plant availability. Bruce B's plant availability in third quarter 2010 was 88 per

cent with 35 outage days compared to an availability of 97 per cent and three outage days in the same period in 2009.

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. Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues in the first nine months of 2010 are expected to be repaid.

TCPL's proportionate share of Bruce Power's Comparable EBITDA decreased \$83 million to \$199 million in the nine months ended September 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, and lower realized prices at Bruce B, partially offset by higher volumes at Bruce B resulting from fewer SBG derates in 2010. The decrease in EBITDA for the nine months ended September 30, 2010 was 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 output from Bruce A in third 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 third quarter 2009. All output from the Bruce B units was subject to a floor price of \$48.96 per MWh in third quarter 2010 and \$48.76 per MWh in third 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 \$57 per MWh in third quarter 2010 reflected revenues recognized from both the floor price mechanism and contract sales, and decreased from the \$66 per MWh in third quarter 2009 due to contracts expiring since that time. A significant portion of the remaining contracts will expire by the end of 2010, which is expected to result in a further reduction in realized prices at Bruce B for future periods. At September 30, 2010, Bruce B had sold forward approximately 200 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 80's for the two operating Bruce A units and in the low 90's 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 in mid-May 2010 with the unit returning to service in late July 2010. A three week planned maintenance outage commenced on October 22, 2010 for Bruce B Unit 5.

As at September 30, 2010, Bruce A had incurred approximately \$3.8 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately \$0.3 billion for the refurbishment of Units 3 and 4.

U.S. Power

U.S. Power Comparable EBITDA⁽¹⁾⁽²⁾

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Revenues				
Power ⁽³⁾	399	222	884	679
Capacity	77	66	187	150
Other ⁽³⁾⁽⁴⁾	15	9	57	66
	<u>491</u>	<u>297</u>	<u>1,128</u>	<u>895</u>
Commodity purchases resold ⁽³⁾	(178)	(78)	(435)	(267)
Plant operating costs and other ⁽⁴⁾	(190)	(139)	(414)	(430)
General, administrative and support costs	(7)	(12)	(25)	(35)
Comparable EBITDA⁽¹⁾	116	68	254	163

(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⁾

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Sales Volumes (GWh)				
Supply				
Generation	2,403	2,021	5,083	4,593
Purchased	2,514	1,259	7,061	3,653
	<u>4,917</u>	<u>3,280</u>	<u>12,144</u>	<u>8,246</u>
Sales				
Contracted	4,129	2,800	11,013	7,206
Spot	788	480	1,131	1,040
	<u>4,917</u>	<u>3,280</u>	<u>12,144</u>	<u>8,246</u>
Plant Availability	96%	97%	91%	78%

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

U.S. Power's Comparable EBITDA for the three months ended September 30, 2010 was \$116 million, an increase of \$48 million compared to the same period in 2009. The increase was primarily due to higher realized prices, higher volumes of power sold and increased capacity revenues. For the nine months ended September 30, 2010, U.S. Power's Comparable EBITDA of \$254 million increased \$91 million from the same period in 2009 primarily due to higher capacity revenues, increased sales volumes 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 nine months ended September 30, 2010 of \$399 million and \$884 million, respectively, increased from \$222 million and \$679 million in the same periods in 2009 primarily due to higher volumes of power sold in addition to higher realized power prices in third quarter 2010, partially offset by the negative impact of a weaker U.S. dollar. Capacity Revenues increased for the three and nine months ended September 30, 2010 to \$77 million and \$187 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. The increases in Capacity Revenues were partially offset by the impact of 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 \$178 million and \$435 million for the three and nine months ended September 30, 2010, respectively, increased from \$78 million and \$267 million in the same periods in 2009 primarily due to an increase in the quantity of power purchased for resale under power sales commitments in New England and New York, as well as higher power prices per MWh purchased in third quarter 2010, partially offset by the positive impact of a weaker U.S. dollar.

Plant Operating Costs and Other in the three months ended September 30, 2010 were \$190 million, an increase of \$51 million over the same period in 2009 primarily due to increased generation volumes, partially offset by the positive impact of a weaker U.S. dollar. In the nine months ended September 30, 2010, Plant Operating Costs and Other were \$414 million, a decrease of \$16 million compared to the same period in 2009, primarily due to the positive impact of a weaker U.S. dollar and the impact of the Ravenswood prior year adjustment, partially offset by higher fuel costs resulting from increased generation.

U.S. Power achieved plant availability of 91 per cent in the nine months ended September 30, 2010 compared to 78 per cent for the same period in 2009 primarily due to the return to service of Ravenswood Unit 30 in May 2009 following an unplanned outage.

In the three and nine months ended September 30, 2010, 84 per cent and 91 per cent, respectively, of power sales volumes were sold under contract, compared to 85 per cent and 87 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 September 30, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 3,400 GWh for the remainder of 2010 and 10,000 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 losses of \$3 million and \$22 million in the three and nine months ended September 30, 2010, respectively, resulting from changes in the fair value of 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, while simultaneously entering into contracts to purchase the fuel required to generate the power, thereby reducing exposure to market price volatility and effectively locking 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 excluded from the computation of Comparable EBITDA.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA for the three and nine month periods ended September 30, 2010, was \$26 million and \$95 million, respectively, compared to \$45 million and \$115 million for the

same periods in 2009. The decrease in Comparable EBITDA in third quarter 2010 was primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas price spreads.

Comparable EBITDA excluded net unrealized gains of \$7 million and net unrealized losses of \$8 million in the three and nine months ended September 30, 2010, respectively (2009 – gains of \$14 million and losses of \$6 million, respectively), resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. TCPL manages its proprietary natural gas storage earnings by simultaneously entering into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded in each period on proprietary natural gas inventory 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 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

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Interest on long-term debt ⁽¹⁾	310	317	903	982
Other interest and amortization	23	24	99	41
Capitalized interest	(160)	(113)	(437)	(230)
	173	228	565	793

⁽¹⁾ Includes interest for Junior Subordinated Notes.

Interest Expense for third quarter 2010 decreased \$55 million to \$173 million from \$228 million in third quarter 2009 and for the nine months ended September 30, 2010 decreased \$228 million to \$565 million from \$793 million for the nine months ended September 30, 2009. These 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. The increase in Other Interest and Amortization for the nine months ended September 30, 2010 compared to 2009 was primarily due to higher losses in 2010 compared to 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 third quarter 2010 decreased \$14 million to \$27 million from \$41 million in third quarter 2009 and for the nine months ended September 30, 2010 decreased \$64 million to \$33 million from \$97 million for the nine months ended September 2009. These decreases reflect the impact of a fluctuating U.S. dollar on the translation of U.S. dollar-denominated working capital balances. The decrease for the nine months ended September 30, 2010 was also due to lower gains in 2010 compared to 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income Taxes for the three and nine months ended September 30, 2010 were \$116 million and \$275 million, respectively, compared to \$101 million and \$310 million, respectively, for the same periods in 2009. The increase for third quarter 2010 compared to 2009 was primarily due to higher pre-tax earnings. The decrease for the nine months ended September 30, 2010 compared to 2009 was primarily

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

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 debt issues, as well as unutilized committed revolving bank lines of US\$1.0 billion, \$2.0 billion and US\$1.0 billion, maturing in November 2011, December 2012 and December 2012, respectively. These facilities also support the Company's two commercial paper programs in Canada. In addition, TCPL's proportionate share of unutilized capacity on committed bank facilities at TCPL-operated affiliates was \$118 million with maturity dates from 2011 through 2012. As at September 30, 2010, TCPL had remaining capacity of \$2.0 billion and US\$1.75 billion 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 September 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 and third quarter 2010, partially offset by capital expenditures and dividend payments.

Operating Activities

Funds Generated from Operations⁽¹⁾

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Cash Flows				
Funds generated from operations ⁽¹⁾	849	759	2,483	2,205
(Increase)/decrease in operating working capital	(68)	(200)	(268)	131
Net cash provided by operations	<u>781</u>	<u>559</u>	<u>2,215</u>	<u>2,336</u>

⁽¹⁾ Refer to the Non-GAAP Measures section in this MD&A for further discussion of Funds Generated from Operations.

Net Cash Provided by Operations increased \$222 million and decreased \$121 million for the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009, reflecting increases in Funds Generated from Operations and changes in operating working capital. Funds Generated from Operations for the three and nine months ended September 30, 2010 were \$849 million and \$2.5 billion, respectively, compared to \$759 million and \$2.2 billion for the same periods in 2009. The increases for the three and nine months ended September 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 and an increase in cash generated through earnings.

Investing Activities

TCPL remains committed to executing its \$21 billion capital expenditure program. For the three and nine months ended September 30, 2010, capital expenditures totalled \$1.3 billion and \$3.6 billion, respectively (2009 – \$1.6 billion and \$3.9 billion, respectively), primarily related to the construction of Keystone, refurbishment and restart of Bruce A Units 1 and 2, expansion of the Alberta System, and construction of the Bison and Guadalajara natural gas pipelines and Coolidge and Halton Hills power plants.

Financing Activities

In September 2010, TCPL issued US\$1.0 billion of senior notes maturing October 1, 2020 and bearing interest at 3.80 per cent. 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.

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.

In the three and nine months ended September 30, 2010, TCPL issued 4.6 million and 15.3 million common shares, respectively (2009 – 47.6 million and 51.5 million common shares, respectively) to TransCanada Corporation (TransCanada) for proceeds of \$170 million and \$572 million (2009 – \$1.6 billion and \$1.7 billion) respectively.

The Company is well positioned to fund its existing capital program through its 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.

Dividends

On November 2, 2010, TCPL's Board of Directors declared a quarterly dividend for the quarter ending December 31, 2010 in the aggregate amount equal to the quarterly dividend paid on TransCanada's issued and outstanding common shares at the close of business on December 31, 2010. The dividend is payable on January 31, 2011. The Board also declared a dividend of \$0.70 per share for the period ending January 30, 2011 on TCPL's Series U and Y preferred shares. The dividend is payable on January 31, 2011 to shareholders of record at the close of business on December 31, 2010.

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 January 31, 2011. 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 prepares and files a "Reconciliation to United States GAAP" and also has the option to instead 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. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain expenses and revenues to differ from that which may otherwise be 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 September 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. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis. The IASB is now considering what form a future project might take, if any, to address RRA. As a result of these developments, TCPL does not expect a final RRA standard under IFRS to be effective for 2011.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, TCPL will defer its adoption of IFRS accordingly and continue preparing its consolidated financial statements in 2011 in accordance with Canadian GAAP in order to continue using RRA. During the deferral period, TCPL will continue to actively monitor IASB developments with respect to RRA and other IFRS, but has also undertaken a project to position the Company to instead adopt U.S. GAAP. During the one year deferral period, if it is determined through absence of a new RRA standard or through application of existing IFRS that TCPL cannot apply RRA under IFRS, the Company expects to re-evaluate its decision to adopt IFRS and, instead, adopt 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. Alternatively, the impact of adopting U.S. GAAP is expected to be consistent with that currently reported in its publicly filed “Reconciliation to United States GAAP”.

Contractual Obligations

At September 30, 2010, TCPL had entered into agreements since December 31, 2009 totalling approximately \$395 million to purchase construction materials and services for the Cartier Wind power and Bison natural gas pipeline 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 September 30, 2010, including payments due for the next five years and thereafter. TCPL is currently assessing the impact on its contractual obligations resulting from the Government of Ontario’s announcement of the cancellation of the Oakville power project. For further information on the Company’s 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, except amounts for derivative 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 September 30, 2010, there were no significant amounts past due or impaired.

At September 30, 2010, the Company had a credit risk concentration of \$308 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 September 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 \$52 million (December 31, 2009 - \$73 million). The change in fair value of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized losses of \$1 million and \$20 million, respectively (2009 - gains of \$16 million and losses of \$13 million, respectively), which were recorded as a decrease in Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized gains of \$8 million and \$12 million, respectively (2009 – losses of \$2 million and gains of \$7 million, respectively), 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 liquid open 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 \$6 million at September 30, 2010 (December 31, 2009 – \$12 million). The decrease from December 31, 2009 was primarily due to decreased commodity prices, reduced price volatility and fewer 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 September 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of \$10.1 billion (US\$9.8 billion) and a fair value of \$12.1 billion (US\$11.8 billion). At September 30, 2010, \$91 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)	September 30, 2010		December 31, 2009	
	Fair Value ⁽¹⁾	Notional or Principal Amount	Fair Value ⁽¹⁾	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2015)	87	U.S. 2,150	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	4	U.S. 400	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	-	-	1	U.S. 100
	91	U.S. 2,550	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:

<i>(unaudited)</i> <i>(millions of dollars)</i>	September 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets⁽¹⁾				
Cash and cash equivalents	1,068	1,068	979	979
Accounts receivable and other ⁽²⁾⁽³⁾	1,564	1,622	1,433	1,484
Due from TransCanada Corporation	624	624	845	845
Available-for-sale assets ⁽²⁾	23	23	23	23
	3,279	3,337	3,280	3,331
Financial Liabilities⁽¹⁾⁽³⁾				
Notes payable	1,613	1,613	1,687	1,687
Accounts payable and deferred amounts ⁽⁴⁾	1,295	1,295	1,532	1,532
Due to TransCanada Corporation	2,240	2,240	2,069	2,069
Accrued interest	338	338	380	380
Long-term debt	18,383	22,710	16,664	19,377
Junior subordinated notes	1,020	968	1,036	976
Long-term debt of joint ventures	889	1,021	965	1,025
	25,778	30,185	24,333	27,046

(1) Consolidated Net Income in 2010 included gains of \$11 million (2009 – \$9 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 September 30, 2010, the Consolidated Balance Sheet included financial assets of \$1,130 million (December 31, 2009 – \$968 million) in Accounts Receivable, \$41 million (December 31, 2009 – nil) in Other Current Assets and \$416 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 September 30, 2010, the Consolidated Balance Sheet included financial liabilities of \$1,258 million (December 31, 2009 – \$1,507 million) in Accounts Payable and \$37 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:

September 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	\$238	\$176	-	\$27
Liabilities	\$(189)	\$(179)	\$(9)	\$(38)
Notional Values				
Volumes ⁽³⁾				
Purchases	15,466	114	-	-
Sales	17,965	96	-	-
Canadian dollars	-	-	-	759
U.S. dollars	-	-	U.S. 1,189	U.S. 350
Cross-currency	-	-	47/U.S. 37	-
Net unrealized (losses)/gains in the period ⁽⁴⁾				
Three months ended September 30, 2010	\$(1)	\$4	\$10	\$50
Nine months ended September 30, 2010	\$(27)	\$9	\$(1)	\$33
Net realized gains/(losses) in the period ⁽⁴⁾				
Three months ended September 30, 2010	\$13	\$(10)	\$6	\$(54)
Nine months ended September 30, 2010	\$50	\$(39)	\$8	\$(64)
Maturity dates	2010-2015	2010-2015	2010-2012	2010-2016
Derivative Financial Instruments				
in Hedging Relationships⁽⁵⁾⁽⁶⁾				
Fair Values ⁽²⁾				
Assets	\$163	-	-	\$11
Liabilities	\$(256)	\$(85)	\$(44)	\$(36)
Notional Values				
Volumes ⁽³⁾				
Purchases	15,563	60	-	-
Sales	12,655	-	-	-
U.S. dollars	-	-	U.S. 120	U.S. 1,025
Cross-currency	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period ⁽⁴⁾				
Three months ended September 30, 2010	\$37	\$(19)	-	\$(7)
Nine months ended September 30, 2010	\$(6)	\$(28)	-	\$(26)
Maturity dates	2010-2015	2010-2013	2010-2014	2011-2013

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

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and 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 \$11 million and a notional amount of US\$150 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2010 were \$1 million and \$3 million, respectively, and were included in Interest Expense. In third quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Losses included in Net Income for the three and nine months ended September 30, 2010 were nil and \$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 nine months ended September 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 September 30, 2009	\$(8)	\$21	\$(1)	\$2	\$(7)
Nine months ended September 30, 2009	\$11	\$(4)	\$1	\$4	\$20
Net realized gains/(losses) in the period ⁽⁴⁾					
Three months ended September 30, 2009	\$23	\$(43)	\$1	\$11	\$(5)
Nine months ended September 30, 2009	\$53	\$(56)	-	\$28	\$(14)
Maturity dates ⁽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 September 30, 2009	\$30	\$(8)	-	-	\$(10)
Nine months ended September 30, 2009	\$108	\$(28)	-	-	\$(27)
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 nine months ended September 30, 2009 were \$1 million and \$3 million, respectively, and were included in Interest Expense. In third quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Net Income for the three and nine months ended September 30, 2009 included gains of \$1 million and \$2 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 nine months ended September 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:

<i>(unaudited)</i> <i>(millions of dollars)</i>	September 30, 2010	December 31, 2009
Current		
Other current assets	357	315
Accounts payable	(442)	(340)
Long-term		
Intangibles and other assets	349	260
Deferred amounts	(394)	(272)

Controls and Procedures

As of September 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 September 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 has declined due to the continued negative impact of reduced market prices for power on Energy's results. As discussed in the Recent Developments section of this MD&A, the Company has delayed recognition of EBITDA from Keystone, which is to be offset by higher capitalized interest. For further information on outlook, refer to the MD&A in TCPL's 2009 Annual Report.

Recent Developments

Pipelines

Keystone

The first phase of Keystone extending from Hardisty, Alberta has commenced serving markets in Wood River and Patoka, Illinois. As part of the NEB's approval to begin operations, Keystone will

operate at a reduced maximum operating pressure (MOP) on the Canadian conversion segment of the pipeline, which will reduce throughput capacity below the initial nominal capacity of 435,000 barrels per day (Bbl/d). Additional in-line inspections have been completed and approval from the NEB to remove the MOP restriction is anticipated 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 was over 90 per cent complete at September 30, 2010. Commercial in service of this phase is expected 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 Gulf Coast expansion will extend from Hardisty to a delivery point near 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 Department of State, the lead agency for U.S. federal regulatory approvals, issued a Draft Environmental Impact Statement which concluded that Keystone's expansion to the Gulf Coast would have limited environmental impact. The regulatory process conducted by the Department of State continues with final regulatory approvals expected in the first half of 2011. Construction is expected to begin shortly thereafter.

On September 7, 2010, to address market demands, TCPL commenced a binding open season to obtain firm commitments for the Cushing Marketlink Project, which would transport crude oil from Cushing to the U.S. Gulf Coast. If the open season, which is expected to close in November 2010, is successful, commercial in service is anticipated in first quarter 2013.

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. On September 13, 2010, the Company commenced a binding open season to obtain firm commitments from interested parties for the Bakken Marketlink Project, which would transport crude oil from Baker, Montana to Cushing and to the U.S. Gulf Coast. If the open season, which is expected to close in November 2010, is successful, commercial in service is anticipated in first quarter 2013.

The total capital cost of Keystone is expected to be approximately US\$12 billion. Approximately US\$7 billion has been spent to date, including approximately US\$1 billion for the expansion to the Gulf Coast, with the remaining US\$5 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, cash flow related to Keystone, other than general, administrative and support costs, is being capitalized until the MOP restriction has been removed and the pipeline is capable of operating at pipeline design pressure. Following this, TCPL expects Keystone to begin recording EBITDA, which is anticipated to increase 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.

Canadian Mainline

In any year, tolls on the Canadian Mainline are partially based on projected throughput volumes for the year. Estimated throughput volumes for 2010 are now expected to be lower than was used in setting the tolls for 2010. As a result, amounts collected through tolls are projected to be approximately

15 per cent less than anticipated in 2010. This shortfall is deferred for accounting purposes as it is expected to be collected in future tolls under the framework regulated by the NEB.

TCPL continues to work with stakeholders on developing rate and service changes that respond to changing market dynamics, and a related NEB filing is anticipated before the end of the year.

TCPL's second open season to transport Marcellus volumes on the Canadian Mainline closed on August 25, 2010. This second open season was initiated at the request of prospective shippers and TCPL received over 1.0 billion cubic feet per day (Bcf/d) of interest. A precedent agreement from the first open season was terminated by a customer who re-bid in the second open season. In October 2010, TCPL issued precedent agreements to the bidders in the second open season which will form the basis for TCPL to assess options to meet these service requests and provide support for any related regulatory filings.

Alberta System

In August 2010, the NEB approved the Company's application for the Alberta System's Rate Design Settlement and the Integration of the ATCO Pipelines System with the Alberta System. This approval, which is the product of many months of collaborative work with stakeholders, will permit the provision of streamlined natural gas transmission service to Alberta System customers under a new rate structure that reflects the current business environment.

In September 2010, the NEB approved the Alberta System's 2010 - 2012 Revenue Requirement Settlement Application, which is the result of extensive stakeholder discussions. The settlement has a three year term and:

- incorporates a return of 9.70 per cent on 40 per cent deemed common equity, which is an increase from the return of 8.75 per cent on 35 per cent deemed common equity previously reflected in 2010 results;
- fixes certain annual OM&A costs at \$174 million; and
- provides flow-through treatment of other costs.

On October 19, 2010, the NEB approved final rates for the Alberta System, which reflect the Alberta System Settlement and the Rate Design Settlement.

In August 2010, the Company received final regulatory approvals and commenced construction of the Groundbirch pipeline. When complete, the approximately \$155 million natural gas pipeline will extend the Alberta System into northeast B.C. and connect to natural gas supplies in the Montney shale gas formation. Construction and commissioning is expected to be complete in November 2010. Groundbirch has firm transportation contracts for 1.1 Bcf/d by 2014.

The NEB hearing relating to the Horn River pipeline project is expected to conclude on November 9, 2010 and a decision is expected in first quarter 2011. The approximately \$310 million project is scheduled to be operational in second quarter 2012 with commitments for contracted natural gas of approximately 540 million cubic feet per day (mmcf/d) by 2014.

TCPL continues to advance further pipeline development in B.C. and Alberta to transport unconventional shale gas supply. The Company has received requests for additional natural gas transmission service throughout the northwest portion of the Western Canadian Sedimentary Basin, including the Horn River and Montney areas of B.C. These new requests are expected to result in the need for further extensions and expansions of the Alberta System.

TQM

In July 2010, TQM reached a multi-year settlement agreement with interested parties regarding its annual revenue requirement for 2010, 2011 and 2012. The settlement includes an annual revenue requirement which consists of flow-through and fixed components. Variances between actual costs and those included in the fixed component, comprised of certain OM&A costs, return on rate base, depreciation and municipal taxes, accrue to TQM. In August 2010, the Company filed an application with the NEB requesting regulatory approval of the negotiated settlement. A decision from the NEB is expected in fourth quarter 2010.

Bison

In third quarter 2010, TCPL received final approvals for the Bison natural gas pipeline project. The Company commenced construction in July 2010 on the approximately US\$600 million project which is anticipated to be in service in fourth quarter 2010. The project has long-term contracts for 407 mmcf/d.

Alaska

Interested shippers on the proposed Alaska Pipeline Project submitted conditional commercial bids in the open season that closed July 30, 2010. The project is now working with shippers to resolve those conditions within the project's control. Discussions are expected to be completed over the next several months.

Guadalajara

Construction continues on the approximately US\$320 million Guadalajara natural gas pipeline project in Mexico, which will transport natural gas from Manzanillo to Guadalajara. The pipeline has a contractual in-service date of first quarter 2011 and was approximately 40 per cent complete at September 30, 2010.

Energy

Bruce

Refurbishment work on Bruce A Units 1 and 2 reached a major milestone in October 2010 with the successful installation of the last of the 960 calandria tubes. Atomic Energy of Canada Limited (AECL) has begun de-staffing and will be substantially demobilized from Unit 2 by the end of 2010 and from Unit 1 by second quarter 2011. As a result of experience gained from Unit 2 activities, the project has seen improvements in the amount of time required to complete similar activities for Unit 1.

Subject to regulatory approval, Bruce expects to load fuel in Unit 2 in second quarter 2011 and achieve a first synchronization of the generator to the electrical grid by the end of 2011, with commercial operation expected to occur in first quarter 2012. Bruce expects to load fuel in Unit 1 in third quarter 2011 with a first synchronization of the generator in first quarter 2012 and commercial operation is expected to occur during third quarter 2012.

Plant commissioning and testing is underway and will accelerate at the end of second quarter 2011 when construction activities are essentially complete. TCPL's share of the total capital cost is expected to be approximately \$2.4 billion.

Halton Hills

The \$700 million Halton Hills generating station went into service on September 1, 2010, on time and on budget. Power from the 683 MW natural gas-fired power plant near Halton Hills, Ontario will be sold to the OPA under a 20 year Clean Energy Supply contract.

Kibby Wind

The 66 MW second phase of the Kibby Wind power project went into service on October 26, 2010. This phase included the installation of an additional 22 turbines, which were all erected ahead of schedule. The two phases of the project will produce a combined 132 MW and have a capital cost of US\$350 million.

Coolidge

Construction of the 575 MW Coolidge generating station was approximately 90 per cent complete at September 30, 2010. The approximately US\$500 million generating station is anticipated to be in service by second quarter 2011.

Oakville

On October 7, 2010, the Government of Ontario announced that it would not proceed with the Oakville generating station. TCPL has commenced negotiations with the OPA on a settlement which would terminate the Clean Energy Supply contract and compensate TCPL for the economic consequences associated with the contract's termination.

Share Information

As at October 29, 2010, TCPL had issued and outstanding 676 million common shares, four million Series U preferred shares and four million Series Y preferred shares.

Selected Quarterly Consolidated Financial Data⁽¹⁾

<i>(unaudited) (millions of dollars except per share amounts)</i>	2010			2009				2008
	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	2,129	1,923	1,955	1,986	2,049	1,984	2,162	2,234
Net Income	387	292	301	384	343	316	336	274
Share Statistics								
Net income per share – Basic and Diluted	\$0.57	\$0.43	\$0.46	\$0.58	\$0.55	\$0.52	\$0.55	\$0.47

⁽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, EBIT 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 EBIT 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:

- Third quarter 2010, Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 – 2012 Revenue Requirement Settlement, which resulted in a \$33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized losses of \$3 million pre-tax (\$2 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 \$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.
- 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 decreased \$58 million after tax due to 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 U.S. dollar-denominated 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.

Consolidated Income

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Revenues	2,129	2,049	6,007	6,195
Operating and Other Expenses				
Plant operating costs and other	817	836	2,328	2,443
Commodity purchases resold	301	205	773	616
Depreciation and amortization	326	343	1,010	1,034
	1,444	1,384	4,111	4,093
Financial Charges/(Income)				
Interest expense	173	228	565	793
Interest expense of joint ventures	13	17	44	47
Interest income and other	(27)	(41)	(33)	(97)
	159	204	576	743
Income before Income Taxes and Non-Controlling Interests	526	461	1,320	1,359
Income Taxes				
Current	(50)	23	(168)	114
Future	166	78	443	196
	116	101	275	310
Non-Controlling Interests				
Non-controlling interest in PipeLines LP	25	19	64	51
Non-controlling interest in Portland	(2)	(2)	1	3
	23	17	65	54
Net Income	387	343	980	995
Preferred Share Dividends	6	6	17	17
Net Income Applicable to Common Shares	381	337	963	978

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Cash Generated From Operations				
Net income	387	343	980	995
Depreciation and amortization	326	343	1,010	1,034
Future income taxes	166	89	443	207
Non-controlling interests	23	17	65	54
Employee future benefits funding less than/(in excess) of expense	8	(22)	(36)	(79)
Other	(61)	(11)	21	(6)
	849	759	2,483	2,205
(Increase)/decrease in operating working capital	(68)	(200)	(268)	131
Net cash provided by operations	781	559	2,215	2,336
Investing Activities				
Capital expenditures	(1,297)	(1,557)	(3,565)	(3,943)
Acquisitions, net of cash acquired	-	(653)	-	(902)
Deferred amounts and other	(222)	(11)	(430)	(270)
Net cash used in investing activities	(1,519)	(2,221)	(3,995)	(5,115)
Financing Activities				
Dividends on common and preferred shares	(278)	(266)	(824)	(734)
Advances (to)/from parent	(6)	(223)	392	834
Distributions paid to non-controlling interests	(22)	(19)	(66)	(59)
Notes payable (repaid)/issued, net	(44)	77	(53)	(607)
Long-term debt issued, net of issue costs	1,021	207	2,337	3,267
Reduction of long-term debt	(146)	(9)	(429)	(509)
Long-term debt of joint ventures issued	86	93	164	201
Reduction of long-term debt of joint ventures	(93)	(52)	(232)	(108)
Common shares issued	170	1,550	572	1,676
Net cash provided by financing activities	688	1,358	1,861	3,961
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	(8)	(63)	8	(97)
(Decrease)/Increase in Cash and Cash Equivalents	(58)	(367)	89	1,085
Cash and Cash Equivalents				
Beginning of period	1,126	2,752	979	1,300
Cash and Cash Equivalents				
End of period	1,068	2,385	1,068	2,385
Supplementary Cash Flow Information				
Net income taxes (refunded)/paid	(26)	(63)	17	50
Interest paid, net of capitalized interest	225	297	597	834

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

*(unaudited)**(millions of dollars)*

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	1,068	979
Accounts receivable	1,130	968
Due from TransCanada Corporation	624	845
Inventories	452	511
Other	772	701
	<u>4,046</u>	<u>4,004</u>
Plant, Property and Equipment	35,555	32,879
Goodwill	3,696	3,763
Regulatory Assets	1,491	1,524
Intangibles and Other Assets	2,435	2,500
	<u>47,223</u>	<u>44,670</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	1,613	1,687
Accounts payable	2,154	2,191
Accrued interest	338	380
Current portion of long-term debt	455	478
Current portion of long-term debt of joint ventures	28	212
	<u>4,588</u>	<u>4,948</u>
Due to TransCanada Corporation	2,240	2,069
Regulatory Liabilities	332	385
Deferred Amounts	896	743
Future Income Taxes	3,175	2,893
Long-Term Debt	17,928	16,186
Long-Term Debt of Joint Ventures	861	753
Junior Subordinated Notes	1,020	1,036
	<u>31,040</u>	<u>29,013</u>
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	706	705
Non-controlling interest in Portland	81	80
	<u>787</u>	<u>785</u>
Shareholders' Equity	15,396	14,872
	<u>47,223</u>	<u>44,670</u>

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Net Income	387	343	980	995
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations ⁽¹⁾	(127)	(230)	(47)	(381)
Change in gains and losses on hedges of investments in foreign operations ⁽²⁾	47	113	27	209
Change in gains and losses on derivative instruments designated as cash flow hedges ⁽³⁾	(52)	16	(173)	80
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods ⁽⁴⁾	8	(1)	6	(6)
Other Comprehensive (Loss)/Income	(124)	(102)	(187)	(98)
Comprehensive Income	263	241	793	897

- ⁽¹⁾ Net of income tax expense of \$36 million and \$21 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of \$68 million and \$68 million, respectively).
- ⁽²⁾ Net of income tax expense of \$19 million and \$11 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of \$50 million and \$102 million, respectively).
- ⁽³⁾ Net of income tax recovery of \$33 million and \$117 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of \$4 million and \$20 million, respectively).
- ⁽⁴⁾ Net of income tax expense of \$4 million and \$21 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of \$4 million and \$4 million, respectively).

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

<i>(unaudited)</i> <i>(millions of dollars)</i>	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⁾	(47)	-	(47)
Change in gains and losses on hedges of investments in foreign operations ⁽²⁾	27	-	27
Change in gains and losses on derivative instruments designated as cash flow hedges ⁽³⁾	-	(173)	(173)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods ⁽⁴⁾⁽⁵⁾	-	6	6
Balance at September 30, 2010	<u>(612)</u>	<u>(207)</u>	<u>(819)</u>
Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations ⁽¹⁾	(381)	-	(381)
Change in gains and losses on hedges of investments in foreign operations ⁽²⁾	209	-	209
Changes in gains and losses on derivative instruments designated as cash flow hedges ⁽³⁾	-	80	80
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods ⁽⁴⁾	-	(6)	(6)
Balance at September 30, 2009	<u>(551)</u>	<u>(19)</u>	<u>(570)</u>

⁽¹⁾ Net of income tax expense of \$21 million for the nine months ended September 30, 2010 (2009 - \$68 million expense).

⁽²⁾ Net of income tax expense of \$11 million for the nine months ended September 30, 2010 (2009 - \$102 million expense).

⁽³⁾ Net of income tax recovery of \$117 million for the nine months ended September 30, 2010 (2009 - \$20 million expense).

⁽⁴⁾ Net of income tax expense of \$21 million for the nine months ended September 30, 2010 (2009 - \$4 million expense).

⁽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 \$95 million (\$56 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

<i>(unaudited)</i> <i>(millions of dollars)</i>	Nine months ended September 30	
	2010	2009
Common Shares		
Balance at beginning of period	10,649	8,973
Proceeds from common shares issued	572	1,676
Balance at end of period	<u>11,221</u>	<u>10,649</u>
Preferred Shares		
Balance at beginning and end of period	<u>389</u>	<u>389</u>
Contributed Surplus		
Balance at beginning of period	335	284
Increased ownership in PipeLines LP	-	49
Other	5	4
Balance at end of period	<u>340</u>	<u>337</u>
Retained Earnings		
Balance at beginning of period	4,131	3,789
Net income	980	995
Common share dividends	(829)	(754)
Preferred share dividends	(17)	(17)
Balance at end of period	<u>4,265</u>	<u>4,013</u>
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	(632)	(472)
Other comprehensive (loss)/income	(187)	(98)
Balance at end of period	<u>(819)</u>	<u>(570)</u>
	<u>3,446</u>	<u>3,443</u>
Total Shareholders' Equity	<u>15,396</u>	<u>14,818</u>

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. 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. 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 prepares and files a "Reconciliation to United States GAAP" and also has the option to instead 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. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain expenses and revenues to differ from that which may otherwise be 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 September 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. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis. The IASB is now considering what form a future project might take, if any, to address RRA. As a result of these developments, TCPL does not expect a final RRA standard under IFRS to be effective for 2011.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, TCPL will defer its adoption of IFRS accordingly and continue preparing its consolidated financial statements in 2011 in accordance with Canadian GAAP in order to continue using RRA. During the deferral period, TCPL will continue to actively monitor IASB developments with respect to RRA and other IFRS, but has also undertaken a project to position the Company to instead adopt U.S. GAAP. During the one year deferral period, if it is determined through absence of a new RRA standard or through application of existing IFRS that TCPL cannot apply RRA under IFRS, the Company expects to re-evaluate its decision to adopt IFRS and, instead, adopt 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. Alternatively, the impact of adopting U.S. GAAP is expected to be consistent with that currently reported in its publicly filed "Reconciliation to United States GAAP".

3. Segmented Information

Three months ended September 30 (unaudited)(millions of dollars)	Pipelines		Energy ⁽¹⁾		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Revenues	1,080	1,152	1,049	897	-	-	2,129	2,049
Plant operating costs and other	(366)	(422)	(433)	(386)	(18)	(28)	(817)	(836)
Commodity purchases resold	-	-	(301)	(205)	-	-	(301)	(205)
Depreciation and amortization	(232)	(255)	(94)	(88)	-	-	(326)	(343)
	482	475	221	218	(18)	(28)	685	665
Interest expense							(173)	(228)
Interest expense of joint ventures							(13)	(17)
Interest income and other							27	41
Income taxes							(116)	(101)
Non-controlling interests							(23)	(17)
Net Income							387	343
Preferred share dividends							(6)	(6)
Net Income Applicable to Common Shares							381	337

Nine months ended September 30 (unaudited)(millions of dollars)	Pipelines		Energy ⁽¹⁾		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Revenues	3,270	3,558	2,737	2,637	-	-	6,007	6,195
Plant operating costs and other	(1,092)	(1,210)	(1,170)	(1,144)	(66)	(89)	(2,328)	(2,443)
Commodity purchases resold	-	-	(773)	(616)	-	-	(773)	(616)
Depreciation and amortization	(736)	(773)	(274)	(261)	-	-	(1,010)	(1,034)
	1,442	1,575	520	616	(66)	(89)	1,896	2,102
Interest expense							(565)	(793)
Interest expense of joint ventures							(44)	(47)
Interest income and other							33	97
Income taxes							(275)	(310)
Non-controlling interests							(65)	(54)
Net Income							980	995
Preferred share dividends							(17)	(17)
Net Income Applicable to Common Shares							963	978

⁽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 and Plant Operating Costs and Other to Revenues.

Total Assets

(unaudited)(millions of dollars)	September 30, 2010	December 31, 2009
Pipelines	31,507	29,508
Energy	13,037	12,477
Corporate	2,679	2,685
	47,223	44,670

4. Long-Term Debt

In September 2010, TCPL issued US\$1.0 billion of senior notes maturing October 1, 2020 and bearing interest at 3.80 per cent. These notes were issued under the US\$4.0 billion debt shelf prospectus filed in December 2009.

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 nine months ended September 30, 2010, the Company capitalized interest related to capital projects of \$160 million and \$437 million, respectively (2009 - \$113 million and \$230 million, respectively).

5. Share Capital

In the three and nine months ended September 30, 2010, TCPL issued 4.6 million and 15.3 million common shares, respectively (2009 – 47.6 million and 51.5 million common shares, respectively) to TransCanada Corporation (TransCanada) for proceeds of \$170 million and \$572 million, respectively (2009 – \$1.6 billion and \$1.7 billion, respectively).

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, except amounts for derivative 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 September 30, 2010, there were no significant amounts past due or impaired.

At September 30, 2010, the Company had a credit risk concentration of \$308 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 September 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 \$52 million (December 31, 2009 - \$73 million). The change in fair value of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized losses of \$1 million and \$20 million, respectively (2009 - gains of \$16 million and losses of \$13 million, respectively), which

were recorded as a decrease in Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized gains of \$8 million and \$12 million, respectively (2009 – losses of \$2 million and gains of \$7 million, respectively), 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 liquid open 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 \$6 million at September 30, 2010 (December 31, 2009 – \$12 million). The decrease from December 31, 2009 was primarily due to decreased commodity prices, reduced price volatility and fewer 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 September 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of \$10.1 billion (US\$9.8 billion) and a fair value of \$12.1 billion (US\$11.8 billion). At September 30, 2010, \$91 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) (<i>unaudited</i>) (<i>millions of dollars</i>)	September 30, 2010		December 31, 2009	
	Fair Value ⁽¹⁾	Notional or Principal Amount	Fair Value ⁽¹⁾	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2015)	87	U.S. 2,150	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	4	U.S. 400	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	-	-	1	U.S. 100
	91	U.S. 2,550	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:

<i>(unaudited)</i> <i>(millions of dollars)</i>	September 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets⁽¹⁾				
Cash and cash equivalents	1,068	1,068	979	979
Accounts receivable and other ⁽²⁾⁽³⁾	1,564	1,622	1,433	1,484
Due from TransCanada Corporation	624	624	845	845
Available-for-sale assets ⁽²⁾	23	23	23	23
	3,279	3,337	3,280	3,331
Financial Liabilities⁽¹⁾⁽³⁾				
Notes payable	1,613	1,613	1,687	1,687
Accounts payable and deferred amounts ⁽⁴⁾	1,295	1,295	1,532	1,532
Due to TransCanada Corporation	2,240	2,240	2,069	2,069
Accrued interest	338	338	380	380
Long-term debt	18,383	22,710	16,664	19,377
Junior subordinated notes	1,020	968	1,036	976
Long-term debt of joint ventures	889	1,021	965	1,025
	25,778	30,185	24,333	27,046

⁽¹⁾ Consolidated Net Income in 2010 included gains of \$11 million (2009 – \$9 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 September 30, 2010, the Consolidated Balance Sheet included financial assets of \$1,130 million (December 31, 2009 – \$968 million) in Accounts Receivable, \$41 million (December 31, 2009 – nil) in Other Current Assets and \$416 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 September 30, 2010, the Consolidated Balance Sheet included financial liabilities of \$1,258 million (December 31, 2009 – \$1,507 million) in Accounts Payable and \$37 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:

September 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	\$238	\$176	-	\$27
Liabilities	\$(189)	\$(179)	\$(9)	\$(38)
Notional Values				
Volumes ⁽³⁾				
Purchases	15,466	114	-	-
Sales	17,965	96	-	-
Canadian dollars	-	-	-	759
U.S. dollars	-	-	U.S. 1,189	U.S. 350
Cross-currency	-	-	47/U.S. 37	-
Net unrealized (losses)/gains in the period ⁽⁴⁾				
Three months ended September 30, 2010	\$(1)	\$4	\$10	\$50
Nine months ended September 30, 2010	\$(27)	\$9	\$(1)	\$33
Net realized gains/(losses) in the period ⁽⁴⁾				
Three months ended September 30, 2010	\$13	\$(10)	\$6	\$(54)
Nine months ended September 30, 2010	\$50	\$(39)	\$8	\$(64)
Maturity dates	2010-2015	2010-2015	2010-2012	2010-2016
Derivative Financial Instruments				
in Hedging Relationships⁽⁵⁾⁽⁶⁾				
Fair Values ⁽²⁾				
Assets	\$163	-	-	\$11
Liabilities	\$(256)	\$(85)	\$(44)	\$(36)
Notional Values				
Volumes ⁽³⁾				
Purchases	15,563	60	-	-
Sales	12,655	-	-	-
U.S. dollars	-	-	U.S. 120	U.S. 1,025
Cross-currency	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period ⁽⁴⁾				
Three months ended September 30, 2010	\$37	\$(19)	-	\$(7)
Nine months ended September 30, 2010	\$(6)	\$(28)	-	\$(26)
Maturity dates	2010-2015	2010-2013	2010- 2014	2011-2013

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

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in gigawatt hours (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 \$11 million and a notional amount of US\$150 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2010 were \$1 million and \$3 million, respectively, and were included in Interest Expense. In third quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Losses included in Net Income for the three and nine months ended September 30, 2010 were nil and \$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 nine months ended September 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 September 30, 2009	\$(8)	\$21	\$(1)	\$2	\$(7)
Nine months ended September 30, 2009	\$11	\$(4)	\$1	\$4	\$20
Net realized gains/(losses) in the period ⁽⁴⁾					
Three months ended September 30, 2009	\$23	\$(43)	\$1	\$11	\$(5)
Nine months ended September 30, 2009	\$53	\$(56)	-	\$28	\$(14)
Maturity dates ⁽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 September 30, 2009	\$30	\$(8)	-	-	\$(10)
Nine months ended September 30, 2009	\$108	\$(28)	-	-	\$(27)
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 nine months ended September 30, 2009 were \$1 million and \$3 million, respectively, and were included in Interest Expense. In third quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Net Income for the three and nine months ended September 30, 2009 included gains of \$1 million and \$2 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 nine months ended September 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:

<i>(unaudited)</i> <i>(millions of dollars)</i>	September 30, 2010	December 31, 2009
Current		
Other current assets	357	315
Accounts payable	(442)	(340)
Long-term		
Intangibles and other assets	349	260
Deferred amounts	(394)	(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 September 30, 2010, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in third quarter 2010.

<i>(unaudited)</i> <i>(millions of dollars, pre-tax)</i>	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total
Natural Gas Inventory	-	52	-	52
Derivative Financial Instruments:				
Assets	122	553	25	700
Liabilities	(235)	(582)	(13)	(830)
Available-for-sale assets	23	-	-	23
Guarantee Liabilities ⁽¹⁾	-	-	(16)	(16)
	<u>(90)</u>	<u>23</u>	<u>(4)</u>	<u>(71)</u>

(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:

<i>(unaudited)</i> <i>(millions of dollars, pre-tax)</i>	Derivatives ⁽¹⁾	Guarantees ⁽²⁾	Total
Balance at December 31, 2009	(2)	(9)	(11)
New contracts ⁽³⁾	(15)	(7)	(22)
Settlements	(3)	-	(3)
Transfers out of Level III ⁽⁴⁾	(20)	-	(20)
Change in unrealized gains recorded in Net Income	14	-	14
Change in unrealized gains recorded in Other Comprehensive Income	38	-	38
Balance at September 30, 2010	<u>12</u>	<u>(16)</u>	<u>(4)</u>

(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 losses 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 \$1 million for the three and nine months ended September 30, 2010, respectively.

(4) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a \$20 million decrease or increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at September 30, 2010.

A 100 basis points increase or decrease in the letter of credit rate, with all other variables held constant, would result in an \$8 million increase or decrease, respectively, in the fair value of guarantee liabilities outstanding as at September 30, 2010. Similarly, a 100 basis points increase or decrease in the risk-free interest rate, which is a component of the discount rate, would result in a \$2 million decrease or increase, respectively, in the fair value of guarantee liabilities outstanding as at September 30, 2010.

7. Employee Future Benefits

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

Three months ended September 30 (unaudited)(millions of dollars)	Pension Benefit Plans		Other Benefit Plans	
	2010	2009	2010	2009
Current service cost	12	11	-	-
Interest cost	22	22	2	2
Expected return on plan assets	(27)	(24)	-	-
Amortization of net actuarial loss	2	2	-	1
Amortization of past service costs	1	1	-	-
Net benefit cost recognized	10	12	2	3

Nine months ended September 30 (unaudited)(millions of dollars)	Pension Benefit Plans		Other Benefit Plans	
	2010	2009	2010	2009
Current service cost	37	34	1	1
Interest cost	67	67	6	6
Expected return on plan assets	(81)	(75)	(1)	(1)
Amortization of transitional obligation related to regulated business	-	-	1	1
Amortization of net actuarial loss	6	4	1	2
Amortization of past service costs	3	3	-	-
Net benefit cost recognized	32	33	8	9

8. Commitments and Contingencies

At September 30, 2010, TCPL had entered into agreements since December 31, 2009 totalling approximately \$395 million to purchase construction materials and services for the Cartier Wind power and Bison natural gas pipeline projects. TCPL is currently assessing the impact on its commitments resulting from the Government of Ontario's announcement of the cancellation of the Oakville power project.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues in the first nine months of 2010 are expected to be repaid.

9. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

<i>(unaudited)</i> <i>(millions of dollars)</i>	Maturity Dates	2010		2009	
		Outstanding September 30	Interest Rate	Outstanding December 31	Interest Rate
Discount Notes	2010	2,124	1.1 %	1,959	0.6 %
Credit Facility		(1,500)	2.3 %	(1,114)	2.3 %
		624		845	

The following amounts are included in Due to TransCanada Corporation:

<i>(unaudited)</i> <i>(millions of dollars)</i>	Maturity Dates	2010		2009	
		Outstanding September 30	Interest Rate	Outstanding December 31	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: Terry Cunha/Cecily Dobson (403) 920-7859 or (800) 608-7859.

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