Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated October 31, 2011 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, 2011. In 2011, the Company will prepare its consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP) as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook, which is discussed further in the Changes in Accounting Policies section in this MD&A. This MD&A should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TCPL's 2010 Annual Report for the year ended December 31, 2010. 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’s profile. "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms used but not otherwise defined in this MD&A are identified in the Glossary of Terms contained in TCPL’s 2010 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, including future abandonment costs. 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, outcomes of litigation and arbitration proceedings, 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, including those material risks discussed in the Financial Instruments and Risk Management section in this MD&A, 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 specified, 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, Comparable Interest Expense, Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning prescribed by 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 and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Attributable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes Expense, 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 these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing instruments such as derivatives. The risk management activities which TCPL excludes from Comparable Earnings provide effective economic hedges but do not meet the specific criteria for hedge accounting treatment and, therefore, changes in their fair values are recorded in Net Income each period. The unrealized gains or losses from changes in the fair value of these derivative contracts and natural gas inventory in storage are not considered to be representative of the underlying operations in the current period or the positive margin that will be realized upon settlement. As a result, these amounts have been excluded in the determination of Comparable Earnings.

The tables below present a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. 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 in this MD&A.

Reconciliation of Non-GAAP Measures

For the three months ended September 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines **2011**	2010	Oil Pipelines **2011**	2010	Energy **2011**	2010	Corporate **2011**	2010	Total **2011**	2010
Comparable EBITDA	**721**	714	**156**	-	**399**	311	**(18)**	(18)	**1,258**	1,007
Depreciation and amortization	**(247)**	(232)	**(38)**	-	**(101)**	(94)	**(3)**	-	**(389)**	(326)
Comparable EBIT	**474**	482	**118**	-	**298**	217	**(21)**	(18)	**869**	681
Other Income Statement Items										
Comparable interest expense									**(269)**	(173)
Interest expense of joint ventures									**(13)**	(13)
Comparable interest income and other									**(5)**	27
Comparable income taxes									**(140)**	(115)
Net income attributable to non-controlling interests									**(26)**	(23)
Preferred share dividends									**(6)**	(6)
Comparable Earnings									**410**	378
Specific item (net of tax):										
Risk management activities(1)									**(33)**	3
Net Income Attributable to Common Shares									**377**	381

For the three months ended September 30 *(unaudited)(millions of dollars)*	**2011**	2010
Comparable Interest Expense	**(269)**	(173)
Specific item:		
Risk management activities(1)	**2**	-
Interest Expense	**(267)**	(173)
Comparable Interest Income and Other	**(5)**	27
Specific item:		
Risk management activities(1)	**(39)**	-
Interest Income and Other	**(44)**	27
Comparable Income Taxes	**(140)**	(115)
Specific item:		
Income taxes attributable to risk management activities(1)	**14**	(1)
Income Taxes Expense	**(126)**	(116)

(1)

For the three months ended September 30 *(unaudited)(millions of dollars)*	**2011**	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**(3)**	(3)
Canadian Power derivatives	**(3)**	-
Natural Gas Storage proprietary inventory and derivatives	**(4)**	7
Interest rate derivatives	**2**	-
Foreign exchange derivatives	**(39)**	-
Income taxes attributable to risk management activities	**14**	(1)
Risk Management Activities	**(33)**	3

For the nine months ended September 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines **2011**	2010	Oil Pipelines **2011**	2010	Energy **2011**	2010	Corporate **2011**	2010	Total **2011**	2010
Comparable EBITDA	**2,228**	2,178	**408**	-	**1,043**	824	**(57)**	(66)	**3,622**	2,936
Depreciation and amortization	**(735)**	(736)	**(95)**	-	**(298)**	(274)	**(10)**	-	**(1,138)**	(1,010)
Comparable EBIT	**1,493**	1,442	**313**	-	**745**	550	**(67)**	(66)	**2,484**	1,926
Other Income Statement Items										
Comparable interest expense									**(770)**	(565)
Interest expense of joint ventures									**(40)**	(44)
Comparable interest income and other									**52**	33
Comparable income taxes									**(450)**	(286)
Net income attributable to non-controlling interests									**(79)**	(65)
Preferred share dividends									**(17)**	(17)
Comparable Earnings									**1,180**	982
Specific item (net of tax):										
Risk management activities[1]									**(47)**	(19)
Net Income Attributable to Common Shares									**1,133**	963

For the nine months ended September 30 *(unaudited)(millions of dollars)*	**2011**	2010
Comparable Interest Expense	**(770)**	(565)
Specific item:		
Risk management activities[1]	**2**	-
Interest Expense	**(768)**	(565)
Comparable Interest Income and Other	**52**	33
Specific item:		
Risk management activities[1]	**(40)**	-
Interest Income and Other	**12**	33
Comparable Income Taxes	**(450)**	(286)
Specific item:		
Income taxes attributable to risk management activities[1]	**22**	11
Income Taxes Expense	**(428)**	(275)

(1)

For the nine months ended September 30 *(unaudited)(millions of dollars)*	**2011**	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**(15)**	(22)
Canadian Power derivatives	**(3)**	-
Natural Gas Storage proprietary inventory and derivatives	**(13)**	(8)
Interest rate derivatives	**2**	-
Foreign exchange derivatives	**(40)**	-
Income taxes attributable to risk management activities	**22**	11
Risk Management Activities	**(47)**	(19)

Consolidated Results of Operations

Third Quarter Results

Comparable Earnings in third quarter 2011 were $410 million compared to $378 million for the same period in 2010. Comparable Earnings in third quarter 2011 excluded net unrealized after-tax losses of $33 million ($47 million pre-tax) (2010 – gains of $3 million after tax ($4 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $32 million in third quarter 2011 compared to the same period in 2010 and reflected the following:

- decreased Natural Gas Pipelines Comparable EBIT primarily due to lower earnings from the Alberta System as a result of the nine-month impact of the 2010 Alberta System Settlement recorded in third quarter 2010 and the negative impact of a weaker U.S. dollar on U.S. operations, partially offset by incremental earnings from Bison and Guadalajara which were placed in service in January 2011 and June 2011, respectively;

- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;

- increased Energy Comparable EBIT primarily due to higher realized power prices in Western Power and incremental earnings from the start-up of Halton Hills in September 2010 and Coolidge in May 2011, partially offset by lower volumes and prices in U.S. Power and lower Natural Gas Storage revenues;

- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone, Halton Hills and Coolidge into service, partially offset by the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;

- decreased Comparable Interest Income and Other, which included realized losses in 2011 compared to gains in 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income; and

- increased Comparable Income Taxes primarily due to higher pre-tax earnings in 2011 compared to 2010.

TCPL's Net Income Attributable to Controlling Interests in third quarter 2011 was $383 million and Net Income Attributable to Common Shares was $377 million compared to $387 million and $381 million, respectively, in third quarter 2010.

Nine Month Results

Comparable Earnings in the first nine months of 2011 were $1,180 million compared to $982 million for the same period in 2010. Comparable Earnings for the first nine months of 2011 excluded net unrealized after-tax losses of $47 million ($69 million pre-tax) (2010 – after-tax losses of $19 million ($30 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $198 million in the first nine months of 2011 compared to the same period in 2010 and reflected the following:

- increased EBIT from Natural Gas Pipelines primarily due to incremental earnings from Bison and Guadalajara, which were placed in service in January 2011 and June 2011, respectively, lower general and administrative expenses, and higher earnings from the Canadian Mainline, partially offset by the negative impact of a weaker U.S. dollar;

- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;

- increased EBIT from Energy primarily due to higher overall realized power prices in Western Power, incremental earnings from the start-up of Halton Hills in September 2010, Coolidge in May 2011 and phase two of Kibby Wind in October 2010, and higher volumes and lower operating expenses due to reduced outage days and higher realized prices at Bruce A, partially offset by lower realized prices and reduced volumes at Bruce B, and decreased third-party and proprietary storage revenues for Natural Gas Storage;

- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and Halton Hills into service, partially offset by the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;

- increased Comparable Interest Income and Other due to higher realized gains in 2011 compared to 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income; and

- increased Comparable Income Taxes primarily due to higher pre-tax earnings in 2011 compared to 2010 and higher positive income tax adjustments in 2010.

TCPL's Net Income Attributable to Controlling Interests in the first nine months of 2011 was $1,150 million and Net Income Attributable to Common Shares was $1,133 million compared to $980 million and $963 million, respectively, for the same period in 2010.

Further discussion of the financial results for the three and nine months ended September 30, 2011 is included in the Natural Gas Pipelines, Oil Pipelines, Energy and Other Income Statement Items sections in this MD&A.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is partially offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The average U.S. dollar to Canadian dollar exchange rate for the three and nine months ended September 30, 2011 was 0.98 and 0.98, respectively (2010 – 1.04 and 1.04, respectively).

Summary of Significant U.S. Dollar-Denominated Amounts

(unaudited)	Three months ended September 30		Nine months ended September 30	
(millions of U.S. dollars, pre-tax)	**2011**	2010	**2011**	2010
U.S. Natural Gas Pipelines Comparable EBIT[1]	**173**	149	**597**	522
U.S. Oil Pipelines Comparable EBIT[1]	**78**	-	**210**	-
U.S. Power Comparable EBIT[1]	**63**	83	**160**	164
Interest on U.S. dollar-denominated long-term debt	**(187)**	(175)	**(549)**	(497)
Capitalized interest on U.S. capital expenditures	**21**	78	**93**	211
U.S. non-controlling interests and other	**(48)**	(39)	**(143)**	(120)
	100	96	**368**	280

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

Natural Gas Pipelines

Natural Gas Pipelines' Comparable EBIT was $474 million and $1,493 million in the three and nine months ended September 30, 2011, respectively, compared to $482 million and $1,442 million, respectively, for the same periods in 2010.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended September 30 **2011**	 2010	Nine months ended September 30 **2011**	 2010
Canadian Natural Gas Pipelines				
Canadian Mainline	**264**	257	**796**	785
Alberta System	**191**	197	**557**	548
Foothills	**31**	34	**96**	102
Other (TQM, Ventures LP)	**13**	12	**38**	39
Canadian Natural Gas Pipelines Comparable EBITDA[1]	**499**	500	**1,487**	1,474
Depreciation and amortization	**(181)**	(167)	**(542)**	(535)
Canadian Natural Gas Pipelines Comparable EBIT[1]	**318**	333	**945**	939
U.S. Natural Gas Pipelines (in U.S. dollars)				
ANR	**58**	64	**239**	238
GTN[2]	**29**	42	**105**	125
Great Lakes[3]	**26**	26	**81**	83
PipeLines LP[4][5]	**26**	26	**76**	73
Iroquois	**15**	16	**50**	51
Bison[2][6]	**8**	-	**35**	-
Portland[5][7]	**2**	1	**15**	12
International (Tamazunchale, Guadalajara, TransGas, Gas Pacifico/INNERGY)[8]	**27**	10	**52**	34
General, administrative and support costs[9]	**(2)**	(16)	**(6)**	(25)
Non-controlling interests[5]	**52**	42	**148**	124
U.S. Natural Gas Pipelines Comparable EBITDA[1]	**241**	211	**795**	715
Depreciation and amortization	**(68)**	(62)	**(198)**	(193)
U.S. Natural Gas Pipelines Comparable EBIT[1]	**173**	149	**597**	522
Foreign exchange	**(3)**	8	**(12)**	22
U.S. Natural Gas Pipelines Comparable EBIT[1] (in Canadian dollars)	**170**	157	**585**	544
Natural Gas Pipelines Business Development Comparable EBITDA[1]	**(14)**	(8)	**(37)**	(41)
Natural Gas Pipelines Comparable EBIT[1]	**474**	482	**1,493**	1,442
Summary:				
Natural Gas Pipelines Comparable EBITDA[1]	**721**	714	**2,228**	2,178
Depreciation and amortization	**(247)**	(232)	**(735)**	(736)
Natural Gas Pipelines Comparable EBIT[1]	**474**	482	**1,493**	1,442

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Results reflect TCPL's direct ownership interest of 75 per cent effective May 3, 2011 and 100 per cent prior to that date.
(3) Represents TCPL's 53.6 per cent direct ownership interest.
(4) Effective May 3, 2011, TCPL's ownership interest in PipeLines LP decreased from 38.2 per cent to 33.3 per cent. As a result, PipeLines LP's results include TCPL's decreased ownership in PipeLines LP and TCPL's effective ownership through PipeLines LP of 8.3 per cent of each of GTN and Bison since May 3, 2011.
(5) Non-Controlling Interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TCPL.
(6) Includes Bison effective January 14, 2011.
(7) Represents TCPL's 61.7 per cent ownership interest.
(8) Includes Guadalajara's operations since June 15, 2011.
(9) Represents General, Administrative and Support Costs associated with certain of TCPL's pipelines.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited) (millions of dollars)	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Canadian Mainline	**61**	66	**186**	196
Alberta System	**51**	70	**149**	145
Foothills	**6**	7	**18**	20

Canadian Natural Gas Pipelines

Canadian Mainline's net income for the three and nine months ended September 30, 2011 decreased $5 million and $10 million, respectively, compared to the same periods in 2010 primarily due to a lower rate of return on common equity (ROE), as determined by the National Energy Board (NEB), of 8.08 per cent in 2011 compared to 8.52 per cent in 2010, as well as a lower average investment base. The impact of the lower ROE and average investment base was partially offset by higher incentive earnings in 2011.

The Alberta System's net income was $51 million and $149 million for the three and nine months ended September 30, 2011 compared to $70 million and $145 million, respectively, for the same periods in 2010. The decrease in net income in third quarter 2011 compared to 2010 was primarily due to the regulatory approval and recognition in September 2010 of the Alberta System Settlement, which included a 9.70 per cent ROE on deemed common equity of 40 per cent, effective January 1, 2010. The increase in net income for the first nine months of 2011 compared to 2010 was primarily due to higher incentive earnings.

Canadian Mainline's Comparable EBITDA for the three and nine months ended September 30, 2011 of $264 million and $796 million, respectively, increased $7 million and $11 million, respectively, compared to the same periods in 2010. The Alberta System's Comparable EBITDA was $191 million and $557 million for the three and nine months ended September 30, 2011 compared to $197 million and $548 million, respectively, for the same periods in 2010. EBITDA from the Canadian Mainline and the Alberta System includes net income variances discussed above as well as flow-through items which do not affect net income.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA for the three and nine months ended September 30, 2011 was US$58 million and US$239 million, respectively, compared to US$64 million and US$238 million, respectively, for the same periods in 2010. The decrease in third quarter 2011 was primarily due to higher operating, maintenance and administration (OM&A) costs. For the nine months ended September 30, 2011, the increase was primarily due to higher transportation and storage revenues, a settlement with a counterparty and increased incidental commodity sales partially offset by higher OM&A costs.

GTN's Comparable EBITDA for the three and nine months ended September 30, 2011 was US$29 million and US$105 million, respectively, compared to US$42 million and US$125 million, respectively, for the same periods in 2010. The decreases were primarily due to TCPL's sale of a 25 per cent interest in GTN to PipeLines LP in May 2011.

The Bison pipeline was placed in service on January 14, 2011. TCPL's portion of Comparable EBITDA was US$8 million and US$35 million for the three and nine months ended September 30, 2011, respectively. EBITDA reflects TCPL's 75 per cent interest in Bison subsequent to the sale of a 25 per cent interest in Bison to PipeLines LP in May 2011 and 100 per cent prior to that date.

Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines was US$146 million and US$416 million for the three and nine months ended September 30, 2011, respectively, compared to

US$105 million and US$352 million, respectively, for the same periods in 2010. The increases were primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service on June 15, 2011, lower general, administrative and support costs and higher Non-Controlling Interests due to the sale of a 25 per cent interest in GTN and Bison to PipeLines LP in May 2011.

Depreciation

Natural Gas Pipelines' depreciation increased $15 million and decreased $1 million for the three and nine months ended September 30, 2011, respectively, compared to the same periods in 2010. The increase in the third quarter was primarily due to an adjustment for the regulatory approval and recognition in September 2010 of the Alberta System Settlement which included a reduction in the composite depreciation rate, effective January 1, 2010, and incremental depreciation for Bison and Guadalajara partially offset by the effect of a weaker U.S. dollar.

Business Development

Natural Gas Pipelines' Business Development Comparable EBITDA loss increased $6 million and decreased $4 million in the three and nine months ended September 30, 2011, respectively, compared to the same periods in 2010. Business development costs increased in third quarter 2011 compared to third quarter 2010 primarily due to greater activity in 2011 for the Alaska Pipeline Project. Business development costs in the first nine months of 2011 decreased primarily due to the increased reimbursement by the State of Alaska to 90 per cent from 50 per cent effective July 31, 2010. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TCPL's joint venture partner in the Alaska Pipeline Project. The decrease in business development costs in the first nine months of 2011 was partially offset by a levy charged by the NEB in March 2011 to recover the Aboriginal Pipeline Group's proportionate share of costs relating to the Mackenzie Gas Project hearings.

Operating Statistics

Nine months ended September 30 *(unaudited)*	Canadian Mainline[(1)] **2011**	2010	Alberta System[(2)] **2011**	2010	Foothills **2011**	2010	ANR[(3)] **2011**	2010
Average investment base (millions of dollars)	**6,250**	6,518	**5,017**	4,986	**611**	661	**n/a**	n/a
Delivery volumes (Bcf)								
Total	**1,474**	1,191	**2,580**	2,535	**948**	1,054	**1,276**	1,171
Average per day	**5.4**	4.4	**9.5**	9.3	**3.5**	3.9	**4.7**	4.3

(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, 2011 were 912 billion cubic feet (Bcf) (2010 – 927 Bcf); average per day was 3.3 Bcf (2010 – 3.4 Bcf).

(2) Field receipt volumes for the Alberta System for the nine months ended September 30, 2011 were 2,643 Bcf (2010 – 2,619 Bcf); average per day was 9.7 Bcf (2010 – 9.6 Bcf).

(3) ANR'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.

Oil Pipelines

Oil Pipelines Comparable EBIT for the three and eight months ended September 30, 2011, was $118 million and $313 million, respectively. At the beginning of February 2011, the Company commenced recording EBITDA for the Wood River/Patoka section of Keystone following the NEB's decision to remove the maximum operating pressure restriction along the conversion section of the system. The Cushing Extension was also placed in service at that time.

Oil Pipelines Results

For the period February 1 to September 30 *(unaudited)(millions of dollars)*	Three months ended September 30 **2011**	Eight months ended September 30 **2011**
Canadian Oil Pipelines Comparable EBITDA[1]	**56**	**146**
Depreciation and amortization	**(14)**	**(36)**
Canadian Oil Pipelines Comparable EBIT[1]	**42**	**110**
U.S. Oil Pipelines Comparable EBITDA[1] (in U.S. dollars)	**102**	**270**
Depreciation and amortization	**(24)**	**(60)**
U.S. Oil Pipelines Comparable EBIT[1]	**78**	**210**
Foreign exchange	**(1)**	**(5)**
U.S. Oil Pipelines Comparable EBIT[1] (in Canadian dollars)	**77**	**205**
Oil Pipelines Business Development Comparable EBITDA[1]	**(1)**	**(2)**
Oil Pipelines Comparable EBIT[1]	**118**	**313**
Summary:		
Oil Pipelines Comparable EBITDA[1]	**156**	**408**
Depreciation and amortization	**(38)**	**(95)**
Oil Pipelines Comparable EBIT[1]	**118**	**313**

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

Operating Statistics

For the period February 1 to September 30 *(unaudited)*	Three months ended September 30 **2011**	Eight months ended September 30 **2011**
Delivery volumes (thousands of barrels)[1]		
Total	**39,696**	**92,329**
Average per day	**431**	**382**

(1) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $298 million and $745 million for the three and nine months ended September 30, 2011, respectively, compared to $217 million and $550 million, respectively, for the same periods in 2010.

Energy Results

(unaudited) (millions of dollars)	Three months ended September 30 **2011**	2010	Nine months ended September 30 **2011**	2010
Canadian Power				
Western Power[1]	**152**	45	**346**	172
Eastern Power[2]	**76**	56	**227**	154
Bruce Power	**86**	89	**219**	199
General, administrative and support costs	**(11)**	(14)	**(28)**	(29)
Canadian Power Comparable EBITDA[3]	**303**	176	**764**	496
Depreciation and amortization	**(72)**	(61)	**(208)**	(179)
Canadian Power Comparable EBIT[3]	**231**	115	**556**	317
U.S. Power (in U.S. dollars)				
Northeast Power[4]	**100**	117	**270**	268
General, administrative and support costs	**(10)**	(6)	**(29)**	(24)
U.S. Power Comparable EBITDA[3]	**90**	111	**241**	244
Depreciation and amortization	**(27)**	(28)	**(81)**	(80)
U.S. Power Comparable EBIT[3]	**63**	83	**160**	164
Foreign exchange	**-**	3	**(3)**	6
U.S. Power Comparable EBIT[3] (in Canadian dollars)	**63**	86	**157**	170
Natural Gas Storage				
Alberta Storage	**14**	28	**66**	101
General, administrative and support costs	**(1)**	(2)	**(6)**	(6)
Natural Gas Storage Comparable EBITDA[3]	**13**	26	**60**	95
Depreciation and amortization	**(3)**	(3)	**(11)**	(11)
Natural Gas Storage Comparable EBIT[3]	**10**	23	**49**	84
Energy Business Development Comparable EBITDA[3]	**(6)**	(7)	**(17)**	(21)
Energy Comparable EBIT[3]	**298**	217	**745**	550
Summary:				
Energy Comparable EBITDA[3]	**399**	311	**1,043**	824
Depreciation and amortization	**(101)**	(94)	**(298)**	(274)
Energy Comparable EBIT[3]	**298**	217	**745**	550

(1) Includes Coolidge effective May 2011.
(2) Includes Halton Hills effective September 2010.
(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(4) Includes phase two of Kibby Wind effective October 2010.

Canadian Power

Western and Eastern Canadian Power Comparable EBIT[(1)(2)]

(unaudited) *(millions of dollars)*	Three months ended September 30 **2011**	2010	Nine months ended September 30 **2011**	2010
Revenues				
Western power	**326**	168	**787**	534
Eastern power	**119**	85	**350**	217
Other[(3)]	**15**	27	**56**	64
	460	280	**1,193**	815
Commodity Purchases Resold				
Western power	**(157)**	(109)	**(401)**	(314)
Other[(4)]	**(4)**	(12)	**(13)**	(24)
	(161)	(121)	**(414)**	(338)
Plant operating costs and other	**(71)**	(58)	**(206)**	(151)
General, administrative and support costs	**(11)**	(14)	**(28)**	(29)
Comparable EBITDA[(1)]	**217**	87	**545**	297
Depreciation and amortization	**(43)**	(33)	**(123)**	(102)
Comparable EBIT[(1)]	**174**	54	**422**	195

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge and Halton Hills effective May 2011 and September 2010, respectively.
(3) Includes sales of excess natural gas purchased for generation and thermal carbon black. The realized gains and losses from derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets are presented on a net basis in Other Revenues.
(4) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics

(unaudited)	Three months ended September 30 **2011**	2010	Nine months ended September 30 **2011**	2010
Sales Volumes (GWh)				
Supply				
Generation				
Western Power[(1)]	**630**	572	**1,937**	1,751
Eastern Power[(2)]	**1,014**	661	**2,862**	1,485
Purchased				
Sundance A & B and Sheerness PPAs[(3)]	**2,074**	2,641	**6,034**	7,755
Other purchases	**352**	89	**728**	311
	4,070	3,963	**11,561**	11,302
Sales				
Contracted				
Western Power[(1)]	**2,474**	2,526	**6,781**	7,368
Eastern Power[(2)]	**1,014**	660	**2,862**	1,500
Spot				
Western Power	**582**	777	**1,918**	2,434
	4,070	3,963	**11,561**	11,302
Plant Availability[(4)]				
Western Power[(1)(5)]	**98%**	94%	**97%**	94%
Eastern Power[(2)(6)]	**96%**	98%	**96%**	97%

(1) Includes Coolidge effective May 2011.
(2) Includes Halton Hills effective September 2010.
(3) No volumes were delivered under the Sundance A PPA in 2011.
(4) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(5) Excludes facilities that provide power to TCPL under PPAs.
(6) Bécancour has been excluded from the availability calculation as power generation has been suspended since 2008.

Western Power's Comparable EBITDA of $152 million and Power Revenues of $326 million in third quarter 2011 increased $107 million and $158 million, respectively, compared to the same periods in 2010, primarily due to higher realized power prices in Alberta and incremental earnings from Coolidge, which went into service under a 20-year power purchase arrangement (PPA) in May 2011. Certain plant outages and higher demand resulted in average spot market power prices in Alberta increasing 164 per cent to $95 per megawatt hour (MWh) in third quarter 2011 compared to $36 per MWh in third quarter 2010.

Western Power's Comparable EBITDA of $346 million and Power Revenues of $787 million in the first nine months of 2011 increased $174 million and $253 million, respectively, compared to the same period in 2010 primarily due to higher overall realized prices in Alberta and incremental earnings from Coolidge.

Western Power's Comparable EBITDA in the three and nine months ended September 30, 2011 included $48 million and $99 million, respectively, of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 are interruptions of supply in accordance with the terms of the PPA. Refer to the Recent Developments section in this MD&A for further discussion regarding the Sundance A outage.

Western Power's Commodity Purchases Resold of $157 million and $401 million for the three and nine months ended September 30, 2011, respectively, increased $48 million and $87 million, respectively, compared to the same periods in 2010 due to higher volumes at Sheerness, higher PPA costs per MWh and increased direct sales to customers.

Eastern Power's Comparable EBITDA of $76 million and $227 million for the three and nine months ended September 30, 2011, respectively, increased $20 million and $73 million, respectively, compared to the same periods in 2010. Similarly, Eastern Power's Power Revenues of $119 million and $350 million for the three and nine months ended September 30, 2011, respectively, increased $34 million and $133 million, respectively, compared to the same periods in 2010. The increases were primarily due to incremental earnings from Halton Hills, which went into service in September 2010.

Plant Operating Costs and Other, which includes fuel gas consumed in power generation, of $71 million and $206 million for the three and nine months ended September 30, 2011, increased $13 million and $55 million, respectively, compared to the same periods in 2010. The increases were primarily due to incremental fuel consumed at Halton Hills.

Depreciation and amortization increased $10 million and $21 million for the three and nine months ended September 30, 2011, respectively, compared to the same periods in 2010 primarily due to incremental depreciation from Halton Hills and Coolidge.

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 sold is also 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 81 per cent of Western Power sales volumes were sold under contract in third quarter 2011, compared to 76 per cent in third quarter 2010. To reduce its exposure to spot market prices on uncontracted volumes, as at September 30, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 2,300 gigawatt hours (GWh) in fourth quarter 2011 and 7,700 GWh for 2012.

Eastern Power is focused on selling power under long-term contracts. In third quarter 2011 and 2010, 100 per cent 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 2011 and in 2012.

Bruce Power Results

(TCPL's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended September 30 **2011**	 2010	Nine months ended September 30 **2011**	 2010
Revenues[1]	**221**	212	**636**	634
Operating Expenses	**(135)**	(123)	**(417)**	(435)
Comparable EBITDA[2]	**86**	89	**219**	199
Bruce A Comparable EBITDA[2]	**33**	35	**99**	58
Bruce B Comparable EBITDA[2]	**53**	54	**120**	141
Comparable EBITDA[2]	**86**	89	**219**	199
Depreciation and amortization	**(29)**	(28)	**(85)**	(77)
Comparable EBIT[2]	**57**	61	**134**	122
Bruce Power – Other Information				
Plant availability				
Bruce A	**97%**	92%	**98%**	77%
Bruce B	**94%**	88%	**88%**	90%
Combined Bruce Power	**95%**	89%	**91%**	86%
Planned outage days				
Bruce A	**-**	-	**5**	60
Bruce B	**19**	7	**92**	54
Unplanned outage days				
Bruce A	**4**	7	**13**	55
Bruce B	**-**	28	**24**	34
Sales volumes (GWh)				
Bruce A	**1,489**	1,446	**4,425**	3,556
Bruce B	**2,111**	2,003	**5,903**	6,102
	3,600	3,449	**10,328**	9,658
Results per MWh				
Bruce A power revenues	**$66**	$65	**$66**	$65
Bruce B power revenues[3]	**$53**	$57	**$54**	$58
Combined Bruce Power revenues	**$57**	$60	**$58**	$60

(1) Revenues include Bruce A's fuel cost recoveries of $7 million and $21 million for the three and nine months ended September 30, 2011, respectively (2010 – $7 million and $21 million).
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(3) Includes revenues received under the floor price mechanism, from deemed generation, including the associated volumes, and from contract settlements.

TCPL's proportionate share of Bruce A's Comparable EBITDA decreased $2 million in third quarter 2011 to $33 million compared to $35 million in third quarter 2010 as a result of higher operating costs, partially offset by increased revenues from higher volumes and higher realized prices.

TCPL's proportionate share of Bruce B's Comparable EBITDA decreased $1 million in third quarter 2011 to $53 million compared to $54 million in third quarter 2010 as a result of increased revenues from higher volumes being more than offset by lower realized prices due to the expiration of fixed price contracts at higher prices.

TCPL's proportionate share of Bruce A's Comparable EBITDA increased $41 million in the nine months ended September 30, 2011 to $99 million compared to the same period in 2010 primarily due to higher volumes and lower operating costs due to a decrease in outage days. Results for the nine months ended September 30, 2010 included a payment made from Bruce B to Bruce A regarding 2009 amendments to a long-term agreement with the Ontario Power Authority (OPA). The net positive impact reflected TCPL's higher percentage ownership interest in Bruce A.

TCPL's proportionate share of Bruce B's Comparable EBITDA decreased $21 million in the nine months ended September 30, 2011 to $120 million compared to the same period in 2010 primarily due to lower realized prices resulting from the expiration of fixed-price contracts at higher prices as well as lower volumes and higher operating costs due to increased outage days. Bruce B results for the nine months ended September 30, 2010 included the above-noted payment in first quarter 2010 to Bruce A.

Under a contract with the OPA, all output from Bruce A in third quarter 2011 was sold at a fixed price of $66.33 per MWh (before recovery of fuel costs from the OPA) compared to $64.71 per MWh in third quarter 2010. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $50.18 per MWh in third quarter 2011 compared to $48.96 per MWh in third quarter 2010. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

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. With respect to 2011, TCPL currently expects spot prices to be less than the floor price for the remainder of the year, therefore no amounts recorded in revenues in the first nine months of 2011 are expected to be repaid.

Bruce B 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 decreased by $4 per MWh to $53 per MWh and $54 per MWh for the three and nine months ended September 30, 2011, respectively, and reflected revenues recognized from both the floor price mechanism and contract sales. The decreases were a result of the majority of higher-priced contracts entered into in previous years having expired by the end of December 2010. As the remainder of these higher-priced contracts continue to expire, a further reduction in realized prices at Bruce B is expected.

The overall plant availability percentage in 2011 is expected to be in the mid-80s for the two operating Bruce A units and for the four Bruce B units. Bruce B began an approximate seven week outage on Unit 5 on October 14, 2011, and Bruce A will commence an approximate six month outage (West Shift Plus program) on Unit 3 starting in November 2011.

As at September 30, 2011, TCPL's share of the total capital cost of the Bruce A refurbishment and restart of Units 1 and 2 was $2.2 billion and was approximately $136 million for the refurbishment of Units 3 and 4.

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

(unaudited)	Three months ended September 30		Nine months ended September 30	
(millions of U.S. dollars)	**2011**	2010	**2011**	2010
Revenues				
Power(3)	**280**	383	**759**	852
Capacity	**70**	74	**183**	180
Other(4)	**11**	14	**54**	54
	361	471	**996**	1,086
Commodity purchases resold	**(112)**	(172)	**(327)**	(420)
Plant operating costs and other(4)	**(149)**	(182)	**(399)**	(398)
General, administrative and support costs	**(10)**	(6)	**(29)**	(24)
Comparable EBITDA(1)	**90**	111	**241**	244
Depreciation and amortization	**(27)**	(28)	**(81)**	(80)
Comparable EBIT(1)	**63**	83	**160**	164

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes phase two of Kibby Wind effective October 2010.
(3) The realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.
(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics(1)

(unaudited)	Three months ended September 30 2011	2010	Nine months ended September 30 2011	2010
Physical Sales Volumes (GWh)				
Supply				
Generation	**2,137**	2,403	**5,369**	5,083
Purchased	**1,657**	2,514	**4,777**	7,061
	3,794	4,917	**10,146**	12,144
Plant Availability(2)(3)	**96%**	96%	**88%**	91%

(1) Includes phase two of Kibby Wind effective October 2010.
(2) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(3) Plant availability decreased in the nine months ended September 30, 2011 due to the impact of planned outages at Ravenswood and OSP.

U.S Power's Comparable EBITDA of US$90 million and US$241 million for the three and nine months ended September 30, 2011, respectively, decreased US$21 million and US$3 million, respectively, compared to the same periods in 2010 primarily due to lower volumes of power sold and lower realized prices partially offset by new sales activity in the PJM Interconnection area (PJM), an increase in the New York commercial customer base and incremental earnings from phase two of Kibby Wind which went into service in October 2010.

U.S. Power's Power Revenues of US$280 million for the three months ended September 30, 2011, decreased US$103 million compared to the same period in 2010 primarily due to lower volumes of power sold and lower realized prices on power sales partially offset by new sales activity in PJM and New York. For the nine months ended September 30, 2011, Power Revenues of US$759 million, decreased US$93 million compared to the same period in 2010, primarily due to lower volumes of power sold, partially offset by new sales activity in PJM and New York.

Capacity Revenues of US$70 million for the three months ended September 30, 2011, decreased US$4 million compared to the same period in 2010. For the nine months ended September 30, 2011, Capacity Revenues of US$183 million increased US$3 million compared to the same period in 2010. Capacity Revenues in third quarter 2011 were negatively impacted by low spot prices in New York as a result of the capacity price issue described in the Recent Developments section of this MD&A. Capacity revenues throughout 2010 were negatively impacted by higher forced outage rates at Ravenswood.

Commodity Purchases Resold of US$112 million and US$327 million for the three and nine months ended September 30, 2011, respectively, decreased US$60 million and US$93 million, respectively, compared to the same periods in 2010 primarily due to a decrease in the quantity of power purchased for resale.

Plant Operating Costs and Other, including fuel gas consumed in generation, of US$149 million in third quarter 2011, decreased US$33 million compared to the same period in 2010 primarily due to lower quantities of fuel purchased as a result of decreased generation. For the nine months ended September 30, 2011, Plant Operating Costs and Other of US$399 million was consistent with the same period in 2010.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM power markets. Exposure to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts. As at September 30, 2011, approximately 1,600 GWh or 73 per cent and 2,800 GWh or 31 per cent of U.S. Power's planned generation is contracted for fourth quarter 2011 and fiscal 2012, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets, and power sales fluctuate based on customer usage.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA for the three and nine month periods ended September 30, 2011, was $13 million and $60 million, respectively, compared to $26 million and $95 million for the same periods in 2010. The decreases in Comparable EBITDA in 2011 were primarily due to decreased third party and proprietary storage revenues as a result of lower realized natural gas price spreads, partially offset by lower operating costs.

Other Income Statement Items

Comparable Interest Expense[1]

(unaudited) (millions of dollars)	Three months ended September 30 2011	2010	Nine months ended September 30 2011	2010
Interest on long-term debt[2]				
Canadian dollar-denominated	**121**	128	**365**	388
U.S. dollar-denominated	**187**	175	**549**	497
Foreign exchange	**(4)**	7	**(12)**	18
	304	310	**902**	903
Other interest and amortization	**31**	23	**99**	99
Capitalized interest	**(66)**	(160)	**(231)**	(437)
Comparable Interest Expense[1]	**269**	173	**770**	565

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable Interest Expense.
(2) Includes interest on Junior Subordinated Notes.

Comparable Interest Expense for third quarter 2011 increased $96 million to $269 million from $173 million in third quarter 2010. Comparable Interest Expense for the nine months ended September 30, 2011 increased $205 million to $770 million from $565 million for the nine months ended September 30, 2010. The increases reflected lower capitalized interest for Keystone and Halton Hills as a result of placing these assets into service and incremental interest expense on debt issues of US$1.25 billion in June 2010 and US$1.0 billion in September 2010. These increases were partially offset by realized gains in 2011 compared to losses in 2010 on derivatives used to manage the Company's exposure to rising interest rates, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest costs and Canadian dollar-denominated debt maturities in 2011 and 2010.

Comparable Interest Income and Other for third quarter 2011 decreased $32 million to a loss of $5 million from income of $27 million in third quarter 2010. The decreases in third quarter reflected realized losses in 2011 compared to gains in 2010 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income. Comparable Interest Income and Other for the nine months ended September 30, 2011 increased $19 million to $52 million from $33 million for the nine months ended September 30, 2010. The increase for the nine months ended September 30, 2011 reflected higher realized gains in 2011 compared to 2010 on similar foreign exchange derivatives.

Comparable Income Taxes were $140 million in third quarter 2011 compared to $115 million for the same period in 2010. Comparable Income Taxes for the nine months ended September 30, 2011 were

$450 million compared to $286 million for the same period in 2010. The increases were primarily due to higher pre-tax earnings in 2011 compared to 2010 and higher positive income tax adjustments in 2010 compared to 2011.

Liquidity and Capital Resources

TCPL believes that its financial position remains sound as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TCPL's liquidity is underpinned by predictable cash flow from operations, cash balances on hand and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2011, October 2016, October 2012 and February 2013, respectively. These facilities also support the Company's commercial paper programs. In addition, at September 30, 2011, TCPL's proportionate share of unutilized capacity on committed bank facilities at TCPL-operated affiliates was $183 million with maturity dates in 2012 and 2016. As at September 30, 2011, TCPL had remaining capacity of $2.0 billion and US$1.75 billion under its Canadian debt and U.S. debt shelf prospectuses, respectively.

In November 2011, the Company also intends to file a new US$4.0 billion U.S. debt base shelf prospectus to replace its December 2009 US$4.0 billion U.S. debt base shelf prospectus, which is due to expire in January 2012 and has remaining capacity of US$1.75 billion. TCPL's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

At September 30, 2011, the Company held Cash and Cash Equivalents of $571 million compared to $752 million at December 31, 2010. The decrease in Cash and Cash Equivalents was primarily due to expenditures for the Company's capital program, debt repayments and dividend payments, partially offset by increased Net Cash Provided by Operations.

Operating Activities

Funds Generated from Operations[1]

(unaudited) *(millions of dollars)*	Three months ended September 30 **2011**	2010	Nine months ended September 30 **2011**	2010
Cash Flows				
Funds generated from operations[1]	**948**	849	**2,712**	2,483
Decrease/(increase) in operating working capital	**116**	(68)	**252**	(268)
Net cash provided by operations	**1,064**	781	**2,964**	2,215

(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 $283 million and $749 million for the three and nine months ended September 30, 2011, respectively, compared to the same periods in 2010, largely as a result of changes in operating working capital as well as increased Funds Generated from Operations. Funds Generated from Operations for the three and nine months ended September 30, 2011 were $948 million and $2.7 billion, compared to $849 million and $2.5 billion, respectively, for the same periods in 2010. The increases were primarily due to an increase in cash generated through earnings, partially offset by the recognition in 2010 of current income tax benefits from U.S. bonus tax depreciation.

As at September 30, 2011, TCPL's current liabilities were $5.7 billion and current assets were $4.3 billion resulting in a working capital deficiency of $1.4 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations as well as its ongoing access to capital markets.

Investing Activities

TCPL remains committed to executing its remaining $11 billion capital expenditure program. For the three and nine months ended September 30, 2011, capital expenditures totalled $696 million and $2.1 billion, respectively (2010 – $1.3 billion and $3.6 billion, respectively), primarily related to the construction of Keystone, the refurbishment and restart of Bruce A Units 1 and 2, and expansion of the Alberta System.

Financing Activities

On October 14, 2011, TCPL amended and restated its $2.0 billion committed, syndicated, revolving, extendible credit facility. The amended and restated facility is set to expire October 2016 and is fully available.

On October 14, 2011, a wholly-owned subsidiary of the Company, TransCanada PipeLine USA Ltd., refinanced its existing US$1.0 billion credit facility with a new 364-day, US$1.0 billion committed, syndicated, revolving, extendible credit facility which is fully available.

In August 2011, TransCanada PipeLine USA Ltd. made a principal repayment of US$200 million on its US$700 million, five-year term loan which matures in 2012.

In July 2011, PipeLines LP increased its senior syndicated revolving credit facility to US$500 million and extended the maturity date to July 2016. PipeLines LP's remaining US$300 million term loan matures December 2011, and it is expected it will be refinanced with fixed or floating rate debt at or prior to its maturity.

In June 2011, TCPL retired $60 million of 9.5 per cent Medium-Term Notes and, in January 2011, retired $300 million of 4.3 per cent Medium-Term Notes.

In June 2011, PipeLines LP issued US$350 million of 4.65 per cent Senior Notes due 2021 and cancelled US$175 million of its unsecured syndicated senior credit facility. The proceeds from the issuance were used to reduce PipeLines LP's term loan and senior revolving credit facility, and repay its bridge loan facility.

In May 2011, PipeLines LP completed a public offering of 7.2 million common units at a price of US$47.58 per unit, resulting in gross proceeds of approximately US$345 million. TCPL contributed an additional approximate US$7 million to maintain its general partnership interest and did not purchase any other units. Upon completion of this offering, TCPL's ownership interest in PipeLines LP decreased from 38.2 per cent to 33.3 per cent. In addition, PipeLines LP made draws of US$61 million on a bridge loan facility and of US$125 million on its senior revolving credit facility.

In June 2011, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace an April 2009 $2.0 billion Canadian Medium-Term Notes base shelf prospectus which expired in May 2011 and had remaining capacity of $2.0 billion.

The Company believes it has the capacity to fund its existing capital program through internally-generated cash flow, continued access to capital markets and liquidity underpinned by in excess of $4 billion of committed credit facilities. TCPL's financial flexibility is further bolstered by opportunities for portfolio management, including an ongoing role for PipeLines LP.

Dividends

On October 31, 2011, TCPL's Board of Directors declared a quarterly dividend for the quarter ending December 31, 2011 in the aggregate amount equal to the quarterly dividend paid on TransCanada

Corporation's (TransCanada) issued and outstanding common shares at the close of business on December 30, 2011. The dividend is payable on January 31, 2012. The Board of Directors also declared a dividend of $0.70 per share for the Series U and Series Y preferred shares for the period ending January 30, 2012 and February 1, 2012, respectively, to shareholders of record at the close of business on December 30, 2011. The dividend for the Series U and Series Y preferred shares is payable on January 30, 2012 and February 1, 2012, respectively.

Commencing with the dividends declared April 28, 2011, common shares purchased with reinvested cash dividends under TransCanada's Dividend Reinvestment and Share Purchase Plan (DRP) will no longer be satisfied with shares issued from treasury at a discount but rather will be acquired on the open market at 100 per cent of the weighted average purchase price. Under this plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares.

Contractual Obligations

There have been no material changes to TCPL's contractual obligations from December 31, 2010 to September 30, 2011, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TCPL's 2010 Annual Report.

Significant Accounting Policies and Critical Accounting Estimates

To prepare financial statements that conform with 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, 2010. For further information on the Company's accounting policies and estimates refer to the MD&A in TCPL's 2010 Annual Report.

Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TCPL's 2010 Annual Report except as follows:

Changes in Accounting Policies for 2011

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests
Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a significant impact on the way the Company accounts for future business combinations. Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of income between the controlling and non-controlling interests. Changes resulting from the adoption of Section 1582 were applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

U.S. GAAP/International Financial Reporting Standards
The CICA's 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.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises, such as TCPL, that use rate-regulated accounting (RRA) in order to permit these entities to defer the adoption of IFRS for one year. TCPL deferred its adoption and accordingly will continue to prepare its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA.

In the application of Canadian GAAP, TCPL follows specific accounting guidance under U.S. GAAP unique to a rate-regulated business. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The IASB concluded that the development of RRA under IFRS requires further analysis and removed the RRA project from its current agenda. TCPL does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As an SEC registrant, TCPL prepares and files a "Reconciliation to United States GAAP" and has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012.

U.S. GAAP Conversion Project
Effective January 1, 2012, the Company will begin reporting using U.S. GAAP. The Company's U.S. GAAP conversion team is led by a multi-disciplinary Steering Committee that provides directional leadership for the adoption of U.S. GAAP. Management also updates TCPL's Audit Committee on the progress of the U.S. GAAP project at each Audit Committee meeting and reports regularly to the Company's Board of Directors on the status of the conversion project.

U.S. GAAP training sessions for TCPL staff have been completed and periodic training updates will continue in the future. As noted above, TCPL prepares and files a "Reconciliation to United States GAAP". As a result, significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting standard. The impact to internal controls over financial reporting and disclosure controls and procedures are currently being assessed and necessary changes, if any, will be in place by the end of 2011.

Identified differences between Canadian GAAP and U.S. GAAP that are significant to the Company are explained below and are consistent with those currently reported in the Company's publicly-filed "Reconciliation to United States GAAP."

Joint Ventures

Canadian GAAP requires the Company to account for certain investments using the proportionate consolidation method of accounting whereby TCPL's proportionate share of assets, liabilities, revenues, expenses and cash flows are included in the Company's financial statements. U.S. GAAP does not permit the use of proportionate consolidation with respect to TCPL's joint ventures and requires that such investments be recorded using the equity method of accounting.

Inventory

Canadian GAAP allows the Company's proprietary natural gas inventory held in storage to be recorded at its fair value. Under U.S. GAAP, inventory is recorded at the lower of cost or market.

Income Tax

Canadian GAAP requires an entity to record income tax assets and liabilities resulting from substantively enacted income tax legislation. Under U.S. GAAP, the legislation must be fully enacted for income tax adjustments to be recorded.

Employee Benefits

Canadian GAAP requires an entity to recognize an accrued benefit asset or liability for defined benefit pension and other postretirement benefit plans. Under U.S. GAAP, an employer is required to recognize the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability in its balance sheet and to recognize changes in the funded status through Other Comprehensive Income in the year in which the change occurs.

Debt Issue Costs

Canadian GAAP requires debt issue costs to be included in long-term debt. Under U.S. GAAP these costs are classified as deferred assets.

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, portfolio investments recorded at fair value, 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, and Available-For-Sale Assets in the Non-Derivative Financial Instruments Summary table below. Guarantees, 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, 2011, there were no significant amounts past due or impaired.

At September 30, 2011, the Company had a credit risk concentration of $271 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 Storage Commodity Price Risk

At September 30, 2011, 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 $40 million (December 31, 2010 - $49 million). The change in the fair value adjustment of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2011 resulted in net pre-tax unrealized losses of $1 million and nil, respectively (2010 – nil and losses of $20 million, respectively), which were recorded as adjustments to 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, 2011 resulted in net pre-tax unrealized losses of $3 million and $13 million, respectively (2010 – gains of $7 million and $12 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 $7 million at September 30, 2011 (December 31, 2010 - $12 million). The decrease in VAR is primarily a result of lower price volatility in Western Power.

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, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10 billion (US$10 billion) and a fair value of $12 billion (US$12 billion). At September 30, 2011, $66 million was included in Other Current Assets, $41 million (December 31, 2010 - $181 million) was included in Intangible and Other Assets, $44 million was included in Accounts Payable, and $83 million was included in Deferred Amounts 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, 2011** **Fair Value**(1)	**September 30, 2011** **Notional or Principal Amount**	December 31, 2010 Fair Value(1)	December 31, 2010 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2018)	**19**	**US 3,700**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2011 to 2012)	**(39)**	**US 725**	2	US 100
	(20)	**US 4,425**	181	US 2,900

(1) Fair values equal carrying values.

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

Non-Derivative Financial Instruments Summary

(unaudited) (millions of dollars)	September 30, 2011 Carrying Amount	September 30, 2011 Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value
Financial Assets(1)				
Cash and cash equivalents	**571**	**571**	752	752
Accounts receivable and other(2)(3)	**1,533**	**1,578**	1,564	1,604
Due from TransCanada Corporation	**1,259**	**1,259**	1,363	1,363
Available-for-sale assets(2)	**38**	**38**	20	20
	3,401	**3,446**	3,699	3,739
Financial Liabilities(1)(3)				
Notes payable	**1,865**	**1,865**	2,092	2,092
Accounts payable and deferred amounts(4)	**1,253**	**1,253**	1,444	1,444
Due to TransCanada Corporation	**2,796**	**2,796**	2,703	2,703
Accrued interest	**431**	**431**	361	361
Long-term debt	**18,110**	**22,588**	17,922	21,523
Long-term debt of joint ventures	**855**	**980**	866	971
Junior subordinated notes	**1,030**	**1,034**	985	992
	26,340	**30,947**	26,373	30,086

(1) Consolidated Net Income in the three and nine months ended September 30, 2011 included losses of $7 million and $18 million, respectively, (2010 – losses of $2 million and $11 million, respectively), for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$150 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At September 30, 2011, the Consolidated Balance Sheet included financial assets of $1,206 million (December 31, 2010 – $1,280 million) in Accounts Receivable, $47 million (December 31, 2010 – $40 million) in Other Current Assets and $318 million (December 31, 2010 - $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for the US$350 million (December 31, 2010 – US$250 million) of Long-Term Debt that is adjusted to fair value.

(4) At September 30, 2011, the Consolidated Balance Sheet included financial liabilities of $1,224 million (December 31, 2010 – $1,414 million) in Accounts Payable and $29 million (December 31, 2010 - $30 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, 2011 *(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	**$133**	**$160**	**$-**	**$26**
Liabilities	**$(107)**	**$(195)**	**$(46)**	**$(26)**
Notional Values				
Volumes[(3)]				
Purchases	**21,147**	**136**	**-**	**-**
Sales	**25,884**	**109**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**684**
U.S. dollars	**-**	**-**	**US 1,366**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized gains/(losses) in the period[(4)]				
Three months ended September 30, 2011	**$5**	**$(13)**	**$(41)**	**$1**
Nine months ended September 30, 2011	**$8**	**$(39)**	**$(41)**	**$1**
Net realized gains/(losses) in the period[(4)]				
Three months ended September 30, 2011	**$21**	**$(20)**	**$(7)**	**$3**
Nine months ended September 30, 2011	**$32**	**$(61)**	**$26**	**$8**
Maturity dates	**2011-2018**	**2011-2016**	**2011-2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[(5)(6)]				
Fair Values[(2)]				
Assets	**$46**	**$7**	**$5**	**$18**
Liabilities	**$(182)**	**$(17)**	**$(36)**	**$(8)**
Notional Values				
Volumes[(3)]				
Purchases	**17,728**	**10**	**-**	**-**
Sales	**8,732**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 104**	**US 1,000**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized losses in the period[(4)]				
Three months ended September 30, 2011	**$(54)**	**$(6)**	**$-**	**$(4)**
Nine months ended September 30, 2011	**$(100)**	**$(14)**	**$-**	**$(13)**
Maturity dates	**2011-2017**	**2011-2013**	**2013- 2014**	**2011-2015**

(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 financial held-for-trading derivatives used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and 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 $18 million and a notional amount of US$350 million at September 30, 2011. Net realized gains on fair value hedges for the three and nine months ended September 30, 2011 were $1 million and $5 million, respectively, and were included in Interest Expense. In the three and nine months ended September 30, 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three and nine months ended September 30, 2011, Net Income included gains of $1 million and nil, 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. For the three and nine months ended September 30, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2010
(unaudited)
(all amounts in millions unless otherwise indicated)

	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values[1][2]				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values[2]				
Volumes[3]				
Purchases	15,610	158	-	-
Sales	18,114	96	-	-
Canadian dollars	-	-	-	736
U.S. dollars	-	-	US 1,479	US 250
Cross-currency	-	-	47/US 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[2]	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[1][2]				
Assets	$112	$5	$-	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values[2]				
Volumes[3]				
Purchases	16,071	17	-	-
Sales	10,498	-	-	-
U.S. dollars	-	-	US 120	US 1,125
Cross-currency	-	-	136/US 100	-
Net realized 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[2]	2011-2015	2011-2013	2011-2014	2011-2015

(1) Fair values equal carrying values.
(2) As at December 31, 2010.
(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
(4) Realized and unrealized gains and losses on financial held-for-trading derivatives used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in

Other Comprehensive Income and 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 $8 million and a notional amount of US$250 million at December 31, 2010. 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 the three and nine months ended September 30, 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. For the three and nine months ended September 30, 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**September 30, 2011**	December 31, 2010
Current		
Other current assets	**319**	273
Accounts payable	**(405)**	(337)
Long-term		
Intangibles and other assets	**183**	374
Deferred amounts	**(339)**	(282)

Other Risks

Additional risks faced by the Company are discussed in the MD&A in TCPL's 2010 Annual Report. These risks remain substantially unchanged since December 31, 2010.

Controls and Procedures

As of September 30, 2011, 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 at a reasonable assurance level as at September 30, 2011.

During the quarter ended September 30, 2011, 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 2010 Annual Report, the Company's overall earnings outlook for 2011 has improved due to higher realized power prices in Western Power in the first nine months of 2011, with relatively strong prices expected throughout the remainder of 2011. The Company's earnings outlook could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York and resolution of the Sundance A PPA dispute, as discussed in the Recent Developments section of this MD&A. For further information on outlook, refer to the MD&A in TCPL's 2010 Annual Report.

Recent Developments

Natural Gas Pipelines

Canadian Mainline

2011 Final Tolls
In April 2011, TCPL filed an application with the NEB for approval of Canadian Mainline's final tolls for 2011 determined in accordance with the existing 2007-2011 Tolls Settlement.

In September 2011, the NEB issued its decision on the application whereby it approved the interim tolls as final, including TCPL's proposal to carry forward any revenue variances into the determination of 2012 tolls. However, the NEB determined that TCPL's inclusion of certain elements included in the proposed 2011 revenue requirement will be examined with TCPL's 2012-2013 Tolls Application before a final decision is rendered on the 2011 revenue requirement.

2012-2013 Tolls Application
On September 1, 2011, TCPL filed a comprehensive application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline, including addressing tolls for 2012 and 2013. The application includes components that affect the Alberta System and Foothills (Restructuring Proposal). The application is intended to address the long-term economic viability of the Canadian Mainline and improve the competitiveness of TCPL's regulated Canadian natural gas transportation infrastructure and the Western Canada Sedimentary Basin (WCSB). On October 31, 2011, TCPL filed supplementary information on cost of service and the proposed tolls for 2012 and 2013. The application results in a 2012 Nova Inventory Transfer System to Dawn toll of $1.29 per gigajoule (GJ) which is $0.80 per GJ or 38 per cent lower than the comparable tolls charged in 2011.

In addition, on October 31, 2011, TransCanada filed for interim 2012 tolls on the Alberta System and annual tolls on Foothills to be effective January 1, 2012. These applications are based on the provisions of the current settlements in place for these systems. An application for interim tolls for 2012 on the Canadian Mainline is expected to be filed in mid-November 2011. Final tolls for 2012 on the Canadian Mainline and Alberta System will be determined following the NEB's decision on the Restructuring Proposal.

In response to the application, the NEB held a Pre-hearing Planning Conference on October 12, 2011 for interested parties to provide suggestions on sequencing of the hearing, procedural steps required and the timing of these steps. Based on comments received, the NEB decided that it will hear all of TCPL's Application, including cost of capital, in one proceeding before issuing a decision on the Application. The oral portion of the hearing will commence on June 4, 2012 in Calgary, Alberta.

Marcellus Facilities Expansion
In July, 2011, TCPL filed an application with the NEB to construct approximately $130 million of new facilities required to transport Marcellus shale gas to eastern markets. The NEB rejected the filing in October 2011. TCPL is considering the guidance provided by the NEB in its rejection of the application and expects to re-file an application in the near future.

Alberta System

2011 Final Tolls
In May 2011, TCPL filed for final 2011 tolls that reflect the provisions of the Alberta System 2010 – 2012 Revenue Requirement Settlement and commercial integration of the ATCO Pipelines system. In August 2011, the NEB approved the Alberta System application for final 2011 tolls but held tolls for the

last five months of the year as interim pending TCPL's response to identify a new integration effective date. On August 30, 2011, TCPL filed a revised integration effective date of October 1, 2011 which, along with final tolls for the last five months of the year, was approved on September 8, 2011. Integration was effected on October 1, 2011.

Expansion Projects
The Alberta System's Horn River natural gas pipeline project was approved by the NEB in January 2011 and commenced construction in March 2011, with a targeted completion date of second quarter 2012 and an estimated capital cost of $275 million. In addition, the Company has executed an agreement to extend the Horn River pipeline by approximately 100 kilometres (km) (62 miles) at an estimated capital cost of $230 million. As a result of the extension, additional contractual commitments of 100 mmcf/d are expected to commence in 2014 with volumes increasing to 300 mmcf/d by 2020. An application requesting approval to construct and operate this extension was filed with the NEB on October 14, 2011. The total currently contracted volumes for Horn River, including the extension, are expected to be approximately 900 mmcf/d by 2020.

On June 24, 2011, the NEB approved the construction and operation of a 24 km (15 mile) extension of the Groundbirch natural gas pipeline. Construction commenced in August 2011 with an expected in-service date of April 1, 2012 and an estimated capital cost of approximately $60 million. The project is required to serve 250 mmcf/d of new transportation contracts. TCPL continues to advance further pipeline development in British Columbia (B.C.) and Alberta to transport new natural gas supplies. The Company has filed several applications with the NEB requesting approval of further expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. As at September 30, 2011, including the projects previously discussed, the NEB had approved natural gas pipeline projects with capital costs of approximately $750 million. Further pipeline projects with a total capital cost of approximately $640 million are awaiting NEB decision.

Ongoing business with Western Canadian producers have resulted in new contracts from both the Montney and Horn River shale gas formations. Including the projects discussed above, TCPL has firm commitments to transport 2.9 Bcf/d from northwest Alberta and northeast B.C. by 2014.

Guadalajara

TCPL's US$360 million, 307 km (191 mile) Guadalajara natural gas pipeline went into service on June 15, 2011. All of the pipeline's utilized capacity is under a 25-year contract with Comisión Federal de Electricidad (CFE), Mexico's state-owned electric company. TCPL and the CFE have agreed to add a US$60 million compressor station to the pipeline that is expected to be operational in early 2013.

PipeLines LP

On May 3, 2011, the Company completed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to PipeLines LP for an aggregate purchase price of US$605 million, subject to closing adjustments, which included US$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, PipeLines LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Gross proceeds of approximately US$345 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on PipeLines LP's bridge loan facility and of US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TCPL made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in PipeLines LP and did not purchase any other units. As a result of the common units offering, TCPL's ownership in PipeLines LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Contributed Surplus.

Oil Pipelines

Keystone

On August 26, 2011, the U.S. Department of State (DOS), the lead agency for U.S. federal regulatory approvals, released its Final Environmental Impact Statement (FEIS) for TCPL's Keystone U.S. Gulf Coast Expansion (Keystone XL). The FEIS found that the project would have limited environmental impact and the proposed route would have the least environmental impact of the alternatives considered.

Following the issuance of the FEIS, the DOS initiated a 90 day National Interest Determination (NID) process. As part of the NID process, the DOS held nine public comment meetings in September and October and will consult with other U.S. federal agencies to determine if granting approval for Keystone XL is in the national interest of the U.S. The NID period concludes on November 25, 2011 and a decision on the Presidential Permit is expected by year end.

The capital cost of Keystone XL is estimated to be US$7 billion with US$1.9 billion having been invested as at September 30, 2011. The remainder is expected to be invested between now and the in-service date, which is expected in 2013. Capital costs related to the construction of Keystone XL are subject to capital cost risk and reward sharing mechanisms with Keystone's long-term committed shippers.

In August 2011, TCPL launched two binding open seasons both of which closed October 17, 2011. The first offered capacity to attract long-term firm service contracts for crude oil transportation from Hardisty, Alberta to Houston, Texas (Houston Lateral). The approximate US$600 million Houston Lateral project would involve the expansion of capacity through the addition of pump stations and the construction of an approximate 80 km (50 mile) pipeline extension from the proposed Keystone XL System. The proposed project would double the U.S. Gulf Coast refining market capacity accessible from the Keystone Pipeline System. TCPL is currently analyzing the results of the open season. Pending sufficient shipper commitments and regulatory approvals, the Houston Lateral is expected to be operational in 2014.

The second binding open season offered capacity to attract additional long-term firm service contracts for crude oil transportation from Cushing Oklahoma to Port Arthur or Houston, Texas (Cushing Marketlink). The approximate US$50 million Cushing Marketlink project uses a portion of the facilities that form part of Keystone XL including the Houston Lateral. TCPL is currently analyzing the results of the open season. Pending regulatory approvals, Cushing Marketlink is expected to begin shipping crude oil to Port Arthur in 2013 and to Houston in 2014.

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order on Keystone on June 3, 2011 as a result of two above-ground incidents in second quarter 2011 at pump stations in North Dakota and Kansas, both of which involved the release of small amounts of crude oil. The corrective action order required TCPL to develop and submit a written re-start plan which included steps to facilitate the proper clean-up, investigation, and system improvements and modifications. The restart plan was approved by PHMSA on June 4, 2011. In July and August 2011, work was performed on the Keystone system to improve system reliability. The work was completed as planned and resulted in reduced pipeline capacity during those two months, however, it did not have a significant impact on EBIT.

Energy

Sundance A

The dispute arising out of TransAlta Corporation's claims of force majeure and economic destruction for the Sundance A facility will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in March and April 2012 for these claims. Assuming the hearing concludes within the time allotted, TCPL expects to receive a decision in mid-2012.

TCPL does not believe the owner's claims meet the tests of force majeure or destruction as specified in the PPA and therefore continues to record revenues and costs as though this event is an interruption of supply in accordance with the terms of the PPA. For the nine months ended September 30, 2011, TCPL has recorded $99 million of EBITDA related to the Sundance A PPA. Ultimate recovery of this amount will depend upon the outcome of the arbitration process.

Ravenswood

Since July 2011, spot prices for capacity sales in the New York Zone J market have settled at materially lower levels than prior periods as a result of the manner in which the New York Independent System Operator (NYISO) has applied pricing rules for a new power plant that recently began service in this market. TCPL believes that this application of pricing rules by the NYISO is in direct contravention of a series of Federal Energy Regulatory Commission (FERC) orders which direct how new entrant capacity is to be treated for the purpose of determining capacity prices. TCPL and other parties have filed formal complaints with FERC that are currently pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown.

During third quarter, the demand curve reset process was completed following FERC's acceptance of the NYISO's September 22, 2011 compliance filing. This resulted in increased demand curve rates that apply going forward to 2014 and positively impacted capacity prices in October. The impact on winter 2011/2012 capacity prices is expected to be negligible due to excess capacity in the winter months, exacerbated by the above noted NYISO actions relative to new unit pricing.

Oakville

In October 2010, the Government of Ontario announced that it would not proceed with the $1.2 billion Oakville generating station. In third quarter 2011, TCPL, the Government of Ontario and the Ontario Power Authority reached formal agreement to use an arbitration process to settle the dispute resulting from termination of a 20-year Clean Energy Supply contract with the Ontario Power Authority, which TCPL had been previously awarded. Pursuant to the arbitration agreement, the parties remain in discussions. TCPL expects to be appropriately compensated for the economic consequences associated with the contract's termination.

Bruce Power

Bruce Power continues to progress through the commissioning of Units 1 and 2. Fueling of Unit 1 will commence in November 2011 and the final phases of commissioning for Unit 2 are planned to begin in fourth quarter 2011.

Subject to regulatory approval, Bruce Power expects to achieve first synchronization of Unit 2 to the electrical grid early in first quarter 2012 and commence commercial operation in late first quarter 2012. Bruce Power expects the first synchronization of Unit 1 to the electrical grid in second quarter

2012 and commercial operations to occur during third quarter 2012. TCPL's share of the total capital cost is expected to be approximately $2.4 billion, of which $2.2 billion was incurred as of September 30, 2011.

Zephyr

In June 2011, Zephyr terminated the precedent agreements with its potential shippers as the parties were unable to resolve key commercial issues. In July 2011, one of Zephyr's potential shippers exercised its contractual rights to acquire 100 per cent of the Zephyr project from TCPL.

Bécancour

In June 2011, Hydro-Québec notified TCPL it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2012. Under the original agreement signed in June 2009, Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TCPL will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Coolidge

The US$500 million Coolidge generating station went into service on May 1, 2011. Power from the 575 MW simple-cycle, natural gas-fired peaking facility located near Phoenix, Arizona is sold to the Salt River Project Agricultural Improvement and Power District under a 20-year PPA.

Cartier Wind

Construction continues on the five-stage, 590 MW Cartier Wind project in Québec. As at September 30, 2011, 100 per cent of the wind turbines at Gros-Morne phase 1 and approximately 80 per cent of the wind turbines at Montagne-Sèche had been erected. The 101 MW first phase of the Gros-Morne and 58 MW Montagne-Sèche wind farm projects are expected to be operational in December 2011. The 111 MW Gros-Morne phase two is expected to be operational in December 2012. These are the fourth and fifth Québec-based wind farms of Cartier Wind, which are 62 per cent owned by TCPL. All of the power produced by Cartier Wind is sold under a 20-year PPA to Hydro-Québec.

Share Information

At October 25, 2011, TCPL had 675 million common shares, four million Series U preferred shares and four million Series Y preferred shares issued and outstanding.

Selected Quarterly Consolidated Financial Data[1]

	2011			2010				2009
(millions of dollars)	**Third**	**Second**	**First**	Fourth	Third	Second	First	Fourth
Revenues	**2,393**	**2,143**	**2,243**	2,057	2,129	1,923	1,955	1,986
Net income attributable to controlling interests	**383**	**353**	**414**	276	387	292	301	384
Share Statistics								
Net income per common share – Basic and Diluted	**$0.56**	**$0.51**	**$0.60**	$0.40	$0.57	$0.43	$0.46	$0.58

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars.

Factors Affecting Quarterly Financial Information

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas 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 Oil Pipelines, which consists of the Company's investment in the Keystone crude oil pipeline, annual revenues are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues, EBIT and net income during any particular fiscal year remain relatively stable with fluctuations resulting from planned and unplanned outages, and changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, 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, EBIT and net income are affected by seasonal weather conditions, customer demand, market prices, capacity prices, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that affected the last eight quarters' EBIT and Net Income are as follows:

- Third Quarter 2011, Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of $47 million pre-tax ($33 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Second Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Guadalajara, which was placed in service in June 2011. Energy's EBIT included incremental earnings from Coolidge, which was placed in service in May 2011. EBIT included net unrealized losses of $5 million pre-tax ($4 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- First Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of Keystone in February 2011. EBIT included net unrealized losses of $17 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Fourth Quarter 2010, Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after tax) valuation provision for advances to the APG for the MGP. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of $22 million pre-tax ($12 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Third Quarter 2010, Natural Gas 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 gains of $4 million pre-tax ($3 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Second Quarter 2010, Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of $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 $49 million pre-tax ($32 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Fourth Quarter 2009, Natural Gas 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, which was caused by PipeLines LP's issue of common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended September 30 **2011**	2010	Nine months ended September 30 **2011**	2010
Revenues	**2,393**	2,129	**6,779**	6,007
Operating and Other Expenses				
Plant operating costs and other	**875**	817	**2,456**	2,328
Commodity purchases resold	**270**	301	**732**	773
Depreciation and amortization	**389**	326	**1,138**	1,010
	1,534	1,444	**4,326**	4,111
Financial Charges/(Income)				
Interest expense	**267**	173	**768**	565
Interest expense of joint ventures	**13**	13	**40**	44
Interest income and other	**44**	(27)	**(12)**	(33)
	324	159	**796**	576
Income before Income Taxes	**535**	526	**1,657**	1,320
Income Taxes Expense				
Current	**47**	(50)	**185**	(168)
Future	**79**	166	**243**	443
	126	116	**428**	275
Net Income	**409**	410	**1,229**	1,045
Net Income Attributable to Non-Controlling Interests	**26**	23	**79**	65
Net Income Attributable to Controlling Interests	**383**	387	**1,150**	980
Preferred Share Dividends	**6**	6	**17**	17
Net Income Attributable to Common Shares	**377**	381	**1,133**	963

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended September 30 **2011**	 2010	Nine months ended September 30 **2011**	 2010
Net Income	**409**	410	**1,229**	1,045
Other Comprehensive Income/(Loss), Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**344**	(127)	**216**	(47)
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations(2)	**(213)**	47	**(141)**	27
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**(17)**	(56)	**(109)**	(176)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	**41**	19	**103**	13
Other Comprehensive Income/(Loss)	**155**	(117)	**69**	(183)
Comprehensive Income	**564**	293	**1,298**	862
Comprehensive Income Attributable to Non-Controlling Interests	**26**	30	**87**	69
Comprehensive Income Attributable to Controlling Interests	**538**	263	**1,211**	793
Preferred Share Dividends	**6**	6	**17**	17
Comprehensive Income Attributable to Common Shares	**532**	257	**1,194**	776

(1) Net of income tax recovery of $97 million and $57 million for the three and nine months ended September 30, 2011, respectively (2010 – expense of $36 million and $21 million, respectively).

(2) Net of income tax recovery of $78 million and $51 million for the three and nine months ended September 30, 2011, respectively (2010 – expense of $19 million and $11 million, respectively).

(3) Net of income tax recovery of $9 million and $48 million for the three and nine months ended September 30, 2011, respectively (2010 – recovery of $33 million and $117 million, respectively).

(4) Net of income tax expense of $19 million and $53 million for the three and nine months ended September 30, 2011, respectively (2010 – expense of $4 million and $21 million, respectively).

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) (millions of dollars)	Three months ended September 30 2011	2010	Nine months ended September 30 2011	2010
Cash Generated From Operations				
Net income	**409**	410	**1,229**	1,045
Depreciation and amortization	**389**	326	**1,138**	1,010
Future income taxes	**79**	166	**243**	443
Employee future benefits funding less than/ (in excess of) expense	**10**	8	**2**	(36)
Other	**61**	(61)	**100**	21
	948	849	**2,712**	2,483
Decrease/(increase) in operating working capital	**116**	(68)	**252**	(268)
Net cash provided by operations	**1,064**	781	**2,964**	2,215
Investing Activities				
Capital expenditures	**(696)**	(1,297)	**(2,135)**	(3,565)
Deferred amounts and other	**66**	(222)	**76**	(430)
Net cash used in investing activities	**(630)**	(1,519)	**(2,059)**	(3,995)
Financing Activities				
Dividends on common and preferred shares	**(301)**	(278)	**(884)**	(824)
Advances (to)/from parent	**(10)**	(6)	**197**	392
Distributions paid to non-controlling interests	**(27)**	(22)	**(70)**	(66)
Notes payable issued/(repaid), net	**160**	(44)	**(255)**	(53)
Long-term debt issued, net of issue costs	**54**	1,021	**573**	2,337
Repayment of long-term debt	**(206)**	(146)	**(946)**	(429)
Long-term debt of joint ventures issued	**15**	86	**46**	164
Repayment of long-term debt of joint ventures	**(33)**	(93)	**(82)**	(232)
Common shares issued	**-**	170	**-**	572
Partnership units of subsidiary issued, net of issue costs	**-**	-	**321**	-
Net cash (used in)/provided by financing activities	**(348)**	688	**(1,100)**	1,861
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**30**	(8)	**14**	8
Increase/(Decrease) in Cash and Cash Equivalents	**116**	(58)	**(181)**	89
Cash and Cash Equivalents				
Beginning of period	**455**	1,126	**752**	979
Cash and Cash Equivalents				
End of period	**571**	1,068	**571**	1,068
Supplementary Cash Flow Information				
Income taxes (refunded)/paid, net	**(152)**	(26)	**(113)**	17
Interest paid	**262**	225	**766**	597

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**September 30, 2011**	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	**571**	752
Accounts receivable	**1,206**	1,280
Due from TransCanada Corporation	**1,259**	1,363
Inventories	**428**	425
Other	**793**	777
	4,257	4,597
Plant, Property and Equipment	**37,746**	36,244
Goodwill	**3,729**	3,570
Regulatory Assets	**1,419**	1,512
Intangibles and Other Assets	**1,842**	2,026
	48,993	47,949
LIABILITIES		
Current Liabilities		
Notes payable	**1,865**	2,092
Accounts payable	**2,212**	2,247
Accrued interest	**431**	361
Current portion of long-term debt	**1,083**	894
Current portion of long-term debt of joint ventures	**106**	65
	5,697	5,659
Due to TransCanada Corporation	**2,796**	2,703
Regulatory Liabilities	**292**	314
Deferred Amounts	**779**	694
Future Income Taxes	**3,427**	3,250
Long-Term Debt	**17,027**	17,028
Long-Term Debt of Joint Ventures	**749**	801
Junior Subordinated Notes	**1,030**	985
	31,797	31,434
EQUITY		
Controlling interests	**16,089**	15,747
Non-controlling interests	**1,107**	768
	17,196	16,515
	48,993	47,949

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at December 31, 2010	**(683)**	**(194)**	**(877)**
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**216**	**-**	**216**
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations(2)	**(141)**	**-**	**(141)**
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**-**	**(109)**	**(109)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)(5)	**-**	**95**	**95**
Balance at September 30, 2011	**(608)**	**(208)**	**(816)**

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 financial derivatives to hedge the net investments in foreign operations(2)	27	-	27
Changes 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)	-	6	6
Balance at September 30, 2010	(612)	(207)	(819)

(1) Net of income tax recovery of $57 million for the nine months ended September 30, 2011 (2010 – expense of $21 million).
(2) Net of income tax recovery of $51 million for the nine months ended September 30, 2011 (2010 – expense of $11 million).
(3) Net of income tax recovery of $48 million for the nine months ended September 30, 2011 (2010 – recovery of $117 million).
(4) Net of income tax expense of $53 million for the nine months ended September 30, 2011 (2010 – expense of $21 million).
(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 $101 million ($65 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 Equity

(unaudited) (millions of dollars)	Nine months ended September 30 2011	 2010
Common Shares		
Balance at beginning of period	**11,636**	10,649
Proceeds from common shares issued	**-**	572
Balance at end of period	**11,636**	11,221
Preferred Shares		
Balance at beginning and end of period	**389**	389
Contributed Surplus		
Balance at beginning of period	**341**	335
Dilution gain from PipeLines LP units issued	**30**	-
Other	**4**	5
Balance at end of period	**375**	340
Retained Earnings		
Balance at beginning of period	**4,258**	4,131
Net income attributable to controlling interests	**1,150**	980
Common share dividends	**(886)**	(829)
Preferred share dividends	**(17)**	(17)
Balance at end of period	**4,505**	4,265
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	**(877)**	(632)
Other comprehensive income/(loss)	**61**	(187)
Balance at end of period	**(816)**	(819)
	3,689	3,446
Equity Attributable to Controlling Interests	**16,089**	15,396
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**768**	785
Net income attributable to non-controlling interests		
PipeLines LP	**76**	64
Portland	**3**	1
Other comprehensive income/(loss) attributable to non-controlling interests	**8**	4
Sale of PipeLines LP units		
Proceeds, net of issue costs	**321**	-
Decrease in TCPL's ownership	**(50)**	-
Distributions to non-controlling interests	**(78)**	(68)
Foreign exchange and other	**59**	1
Balance at end of period	**1,107**	787
Total Equity	**17,196**	16,183

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Presentation

The consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook, which is discussed further in Note 2. The accounting policies applied are consistent with those outlined in TCPL's annual audited Consolidated Financial Statements for the year ended December 31, 2010, except as disclosed in Note 2. These Consolidated Financial Statements reflect adjustments, all of which are 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 2010 audited Consolidated Financial Statements included in TCPL's 2010 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 2010 Annual Report. Amounts are stated in Canadian dollars unless otherwise indicated.

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas 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 Oil Pipelines, which consists of the Company's investment in the Keystone crude oil pipeline, annual revenues are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from planned and unplanned outages, and changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, 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

Changes in Accounting Policies for 2011

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a significant impact on the way the Company accounts for future business combinations. Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of income between the controlling and non-controlling interests. Changes resulting from the adoption of Section 1582 were applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

U.S. GAAP/International Financial Reporting Standards

The CICA's 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.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises, such as TCPL, that use rate-regulated accounting (RRA) in order to permit these entities to defer the adoption of IFRS for one year. TCPL deferred its adoption and accordingly will continue to prepare its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA.

In the application of Canadian GAAP, TCPL follows specific accounting guidance under U.S. GAAP unique to a rate-regulated business. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The IASB has concluded that the development of RRA under IFRS requires further analysis and has removed the RRA project from its current agenda. TCPL does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As a registrant with the U.S. Securities and Exchange Commission, TCPL prepares and files a "Reconciliation to United States GAAP" and has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The accounting policies and financial impact of TCPL adopting U.S. GAAP are consistent with that currently reported in the "Reconciliation to United States GAAP" and, as a result, significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting standard.

3. Segmented Information

For the three months ended September 30 (unaudited) (millions of dollars)	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines[1] 2011	Oil Pipelines[1] 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Revenues	1,098	1,080	229	-	1,066	1,049	-	-	2,393	2,129
Plant operating costs and other	(377)	(366)	(73)	-	(407)	(433)	(18)	(18)	(875)	(817)
Commodity purchases resold	-	-	-	-	(270)	(301)	-	-	(270)	(301)
Depreciation and amortization	(247)	(232)	(38)	-	(101)	(94)	(3)	-	(389)	(326)
	474	482	118	-	288	221	(21)	(18)	859	685
Interest expense									(267)	(173)
Interest expense of joint ventures									(13)	(13)
Interest income and other									(44)	27
Income taxes expense									(126)	(116)
Net Income									409	410
Net Income Attributable to Non-Controlling Interests									(26)	(23)
Net Income Attributable to Controlling Interests									383	387
Preferred Share Dividends									(6)	(6)
Net Income Attributable to Common Shares									377	381

For the nine months ended September 30 (unaudited) (millions of dollars)	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines[1] 2011	Oil Pipelines[1] 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Revenues	3,294	3,270	575	-	2,910	2,737	-	-	6,779	6,007
Plant operating costs and other	(1,066)	(1,092)	(167)	-	(1,166)	(1,170)	(57)	(66)	(2,456)	(2,328)
Commodity purchases resold	-	-	-	-	(732)	(773)	-	-	(732)	(773)
Depreciation and amortization	(735)	(736)	(95)	-	(298)	(274)	(10)	-	(1,138)	(1,010)
	1,493	1,442	313	-	714	520	(67)	(66)	2,453	1,896
Interest expense									(768)	(565)
Interest expense of joint ventures									(40)	(44)
Interest income and other									12	33
Income taxes expense									(428)	(275)
Net Income									1,229	1,045
Net Income Attributable to Non-Controlling Interests									(79)	(65)
Net Income Attributable to Controlling Interests									1,150	980
Preferred Share Dividends									(17)	(17)
Net Income Attributable to Common Shares									1,133	963

(1) Commencing in February 2011, TCPL began recording earnings related to the Wood River/Patoka and Cushing Extension sections of Keystone.

Total Assets

(unaudited) *(millions of dollars)*	September 30, 2011	December 31, 2010
Natural Gas Pipelines	23,584	23,592
Oil Pipelines	9,137	8,501
Energy	13,698	12,847
Corporate	2,574	3,009
	48,993	47,949

4. Long-Term Debt

In August 2011, TransCanada PipeLine USA Ltd. made a principal repayment of US$200 million on the US$700 million five-year term loan which matures in 2012.

In July 2011, PipeLines LP increased its senior revolving credit facility to US$500 million and extended the maturity date to July 2016. PipeLines LP's remaining US$300 million term loan matures December 2011 and it is expected it will be refinanced with fixed or floating rate debt at or prior to its maturity.

In June 2011, TCPL retired $60 million of 9.5 per cent Medium-Term Notes and, in January 2011, retired $300 million of 4.3 per cent Medium-Term Notes.

In June 2011, PipeLines LP issued US$350 million of 4.65 per cent Senior Notes due 2021 and cancelled US$175 million of its unsecured syndicated senior credit facility. The proceeds from the issuance were used to reduce PipeLines LP's term loan and senior revolving credit facility, and repay its bridge loan facility.

In the three and nine months ended September 30, 2011, the Company capitalized interest related to capital projects of $66 million and $231 million, respectively (2010 - $160 million and $437 million).

5. Equity and Share Capital

In May 2011, PipeLines LP completed a public offering of 7,245,000 common units at a price of US$47.58 per unit, resulting in gross proceeds of approximately US$345 million. TCPL contributed an additional approximate US$7 million to maintain its general partnership interest and did not purchase any other units. Upon completion of this offering, TCPL's ownership interest in PipeLines LP decreased from 38.2 per cent to 33.3 per cent.

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, portfolio investments recorded at fair value, 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, and Available-For-Sale Assets in the Non-Derivative Financial Instruments Summary table below. Guarantees, 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, 2011, there were no significant amounts past due or impaired.

At September 30, 2011, the Company had a credit risk concentration of $271 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 Storage Commodity Price Risk

At September 30, 2011, 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 $40 million (December 31, 2010 - $49 million). The change in the fair value adjustment of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2011 resulted in net pre-tax unrealized losses of $1 million and nil, respectively (2010 – nil and losses of $20 million, respectively), which were recorded as adjustments to 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, 2011 resulted in net pre-tax unrealized losses of $3 million and $13 million, respectively (2010 – gains of $7 million and $12 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 $7 million at September 30, 2011 (December 31, 2010 - $12 million). The decrease in VAR is primarily a result of lower price volatility in Western Power.

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, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10 billion (US$10 billion) and a fair value of $12 billion (US$12 billion). At September 30, 2011, $66 million was included in Other Current Assets, $41 million (December 31, 2010 - $181 million) was included in Intangible and Other Assets, $44 million was included in Accounts Payable, and $83 million was included in Deferred Amounts 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, 2011** **Fair Value[(1)]**	**September 30, 2011** **Notional or Principal Amount**	December 31, 2010 Fair Value[(1)]	December 31, 2010 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2018)	**19**	**US 3,700**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2011 to 2012)	**(39)**	**US 725**	2	US 100
	(20)	**US 4,425**	181	US 2,900

(1) Fair values equal carrying values.

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

Non-Derivative Financial Instruments Summary

(unaudited) (millions of dollars)	September 30, 2011 Carrying Amount	September 30, 2011 Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**571**	**571**	752	752
Accounts receivable and other[2][3]	**1,533**	**1,578**	1,564	1,604
Due from TransCanada Corporation	**1,259**	**1,259**	1,363	1,363
Available-for-sale assets[2]	**38**	**38**	20	20
	3,401	**3,446**	3,699	3,739
Financial Liabilities[1][3]				
Notes payable	**1,865**	**1,865**	2,092	2,092
Accounts payable and deferred amounts[4]	**1,253**	**1,253**	1,444	1,444
Due to TransCanada Corporation	**2,796**	**2,796**	2,703	2,703
Accrued interest	**431**	**431**	361	361
Long-term debt	**18,110**	**22,588**	17,922	21,523
Long-term debt of joint ventures	**855**	**980**	866	971
Junior subordinated notes	**1,030**	**1,034**	985	992
	26,340	**30,947**	26,373	30,086

(1) Consolidated Net Income in the three and nine months ended September 30, 2011 included losses of $7 million and $18 million, respectively, (2010 – losses of $2 million and $11 million, respectively), for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$150 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At September 30, 2011, the Consolidated Balance Sheet included financial assets of $1,206 million (December 31, 2010 – $1,280 million) in Accounts Receivable, $47 million (December 31, 2010 – $40 million) in Other Current Assets and $318 million (December 31, 2010 - $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for the US$350 million (December 31, 2010 – US$250 million) of Long-Term Debt that is adjusted to fair value.

(4) At September 30, 2011, the Consolidated Balance Sheet included financial liabilities of $1,224 million (December 31, 2010 – $1,414 million) in Accounts Payable and $29 million (December 31, 2010 - $30 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, 2011 *(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	**$133**	**$160**	**$-**	**$26**
Liabilities	**$(107)**	**$(195)**	**$(46)**	**$(26)**
Notional Values				
Volumes[3]				
Purchases	**21,147**	**136**	**-**	**-**
Sales	**25,884**	**109**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**684**
U.S. dollars	**-**	**-**	**US 1,366**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized gains/(losses) in the period[4]				
Three months ended September 30, 2011	**$5**	**$(13)**	**$(41)**	**$1**
Nine months ended September 30, 2011	**$8**	**$(39)**	**$(41)**	**$1**
Net realized gains/(losses) in the period[4]				
Three months ended September 30, 2011	**$21**	**$(20)**	**$(7)**	**$3**
Nine months ended September 30, 2011	**$32**	**$(61)**	**$26**	**$8**
Maturity dates	**2011-2018**	**2011-2016**	**2011-2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$46**	**$7**	**$5**	**$18**
Liabilities	**$(182)**	**$(17)**	**$(36)**	**$(8)**
Notional Values				
Volumes[3]				
Purchases	**17,728**	**10**	**-**	**-**
Sales	**8,732**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 104**	**US 1,000**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized losses in the period[4]				
Three months ended September 30, 2011	**$(54)**	**$(6)**	**$-**	**$(4)**
Nine months ended September 30, 2011	**$(100)**	**$(14)**	**$-**	**$(13)**
Maturity dates	**2011-2017**	**2011-2013**	**2013- 2014**	**2011-2015**

(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 financial held-for-trading derivatives used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and 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 $18 million and a notional amount of US$350 million at September 30, 2011. Net realized gains on fair value hedges for the three and nine months ended September 30, 2011 were $1 million and $5 million, respectively, and were included in Interest Expense. In the three and nine months ended September 30, 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three and nine months ended September 30, 2011, Net Income included gains of $1 million and nil, 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. For the three and nine months ended September 30, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values(1)(2)				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values(2)				
Volumes(3)				
Purchases	15,610	158	-	-
Sales	18,114	96	-	-
Canadian dollars	-	-	-	736
U.S. dollars	-	-	US 1,479	US 250
Cross-currency	-	-	47/US 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(2)	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(1)(2)				
Assets	$112	$5	$-	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values(2)				
Volumes(3)				
Purchases	16,071	17	-	-
Sales	10,498	-	-	-
U.S. dollars	-	-	US 120	US 1,125
Cross-currency	-	-	136/US 100	-
Net realized 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(2)	2011-2015	2011-2013	2011-2014	2011-2015

(1) Fair values equal carrying values.
(2) As at December 31, 2010.
(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
(4) Realized and unrealized gains and losses on financial held-for-trading derivatives used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and 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 $8 million and a notional amount of US$250 million at December 31, 2010. 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 the three and nine months ended September 30, 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. For the three and nine months ended September 30, 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**September 30, 2011**	December 31, 2010
Current		
Other current assets	**319**	273
Accounts payable	**(405)**	(337)
Long-term		
Intangibles and other assets	**183**	374
Deferred amounts	**(339)**	(282)

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. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets 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.

There were no transfers between Level I and Level II in the three and nine months ended September 31, 2011. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

Assets/(Liabilities)	Quoted Prices in Active Markets (Level 1)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
(unaudited) *(millions of dollars, pre-tax)*	**Sept 30 2011**	Dec 31 2010	**Sept 30 2011**	Dec 31 2010	**Sept 30 2011**	Dec 31 2010	**Sept 30 2011**	Dec 31 2010
Natural Gas Inventory	**-**	-	**40**	49	**-**	-	**40**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**44**	28	**-**	-	**44**	28
Foreign exchange contracts	**5**	10	**107**	179	**-**	-	**112**	189
Power commodity contracts	**-**	-	**166**	269	**2**	5	**168**	274
Natural gas commodity contracts	**88**	93	**79**	56	**-**	-	**167**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(34)**	(47)	**-**	-	**(34)**	(47)
Foreign exchange contracts	**(71)**	(11)	**(138)**	(54)	**-**	-	**(209)**	(65)
Power commodity contracts	**-**	-	**(260)**	(299)	**(18)**	(8)	**(278)**	(307)
Natural gas commodity contracts	**(162)**	(178)	**(50)**	(15)	**-**	-	**(212)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**38**	20	**-**	-	**-**	-	**38**	20
	(102)	(66)	**(46)**	166	**(16)**	(3)	**(164)**	97

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

(unaudited) *(millions of dollars, pre-tax)*	Derivatives[1] **2011**	Derivatives[1] 2010
Balance at January 1	**(3)**	(2)
New contracts[2]	**1**	(15)
Transfers out of Level III[3]	**(2)**	(20)
Settlements	**-**	(3)
Change in unrealized gains recorded in Net Income	**1**	14
Change in unrealized (losses)/gains recorded in Other Comprehensive Income	**(13)**	38
Balance at September 30	**(16)**	12

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) For the three and nine months ended September 30, 2011, there were no amounts (2010 – gain of $1 million and nil, respectively), included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date.
(3) As contracts near maturity and inputs become observable, 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 $10 million decrease or increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at September 30, 2011.

7. Employee Future Benefits

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

Three months ended September 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2011**	2010	**2011**	2010
Current service cost	**14**	12	**-**	-
Interest cost	**23**	22	**2**	2
Expected return on plan assets	**(29)**	(27)	**-**	-
Amortization of transitional obligation related to regulated business	**-**	-	**-**	-
Amortization of net actuarial loss	**5**	2	**-**	-
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**14**	10	**2**	2

Nine months ended September 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2011**	2010	**2011**	2010
Current service cost	**41**	37	**1**	1
Interest cost	**68**	67	**6**	6
Expected return on plan assets	**(85)**	(81)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**16**	6	**1**	1
Amortization of past service costs	**3**	3	**-**	-
Net benefit cost recognized	**43**	32	**8**	8

8. Dispositions

On May 3, 2011, the Company completed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to PipeLines LP for an aggregate purchase price of US$605 million, subject to closing adjustments, which included US$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, PipeLines LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Gross proceeds of approximately US$345 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on PipeLines LP's bridge loan facility and of US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TCPL made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in PipeLines LP and did not purchase any other units. As a result of the common units offering, TCPL's ownership in PipeLines LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Contributed Surplus.

9. Contingencies

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. With respect to 2011, TCPL currently expects spot prices to be less than the floor price for the remainder of the year, therefore no amounts recorded in revenues in the first nine months of 2011 are expected to be repaid.

10. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

		2011		2010	
(millions of dollars)	Maturity Dates	**Outstanding September 30**	**Interest Rate**	Outstanding December 31	Interest Rate
Discount Notes	2011	**2,674**	**1.4%**	2,566	1.4%
Credit Facility		**(1,415)**	**3.0%**	(1,203)	2.3%
		1,259		1,363	

The following amounts are included in Due to TransCanada Corporation:

		2011		2010	
(millions of dollars)	Maturity Dates	**Outstanding September 30**	**Interest Rate**	Outstanding December 31	Interest Rate
Credit Facility	2012	**2,796**	**3.8%**	2,703	3.8%

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/Lee Evans at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: James Millar/Terry Cunha/Shawn Howard (403) 920-7859 or (800) 608-7859.

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