Quarterly Report to Shareholders

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) dated October 29, 2012 should be read in conjunction with the accompanying unaudited Condensed Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) for the three and nine months ended September 30, 2012. The condensed consolidated financial statements of the Company have been prepared in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP). Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook (CGAAP), have been adjusted as necessary to be compliant with the Company's accounting policies under U.S. GAAP, 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 2011 Annual Report, as prepared in accordance with CGAAP, for the year ended December 31, 2011. 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 2011 Annual Report.

Forward-Looking Information

This MD&A contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "will", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are typically 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 plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

- anticipated business prospects;
- financial and operational performance of TCPL and its subsidiaries and affiliates;
- expectations or projections about strategies and goals for growth and expansion;
- expected cash flows;
- expected costs;
- expected costs for projects under construction;
- expected schedules for planned projects (including anticipated construction and completion dates);
- expected regulatory processes and outcomes;
- expected outcomes with respect to legal proceedings, including arbitration;
- expected capital expenditures and contractual obligations;
- expected operating and financial results; and
- expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made and, as such, are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TCPL's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TCPL's forward-looking statements are based include, but are not limited to, assumptions about:

- commodity and capacity prices;
- inflation rates;
- timing of debt issuances and hedging;
- regulatory decisions and outcomes;
- arbitration decisions and outcomes;
- foreign exchange rates;
- interest rates;
- tax rates;
- planned and unplanned outages and utilization of the Company's pipeline and energy assets;
- asset reliability and integrity;
- access to capital markets;
- anticipated construction costs, schedules and completion dates; and
- acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

- 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;
- amount of capacity payments and revenues from the Company's energy business;
- regulatory decisions and outcomes;
- outcomes with respect to legal proceedings, including arbitration;
- counterparty performance;
- changes in political environment;
- 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;
- weather;
- technological developments; and
- economic conditions in North America.

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 against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise stated, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to publicly update or revise any forward-looking information in this MD&A or otherwise stated, 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 as prescribed by U.S. GAAP. They are, therefore, considered to be non-GAAP measures and are unlikely to 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. EBITDA includes income from equity investments. 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. EBIT includes income from equity investments.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes, respectively, and are 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 adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments. These non-GAAP measures are calculated on a consistent basis from period to period. The specific items for which such measures are adjusted in each applicable period may only be relevant in certain periods and are disclosed in the Reconciliation of Non-GAAP Measures table in this MD&A.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing 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 year. The unrealized gains or losses from changes in the fair value of these derivative contracts 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 Reconciliation of Non-GAAP Measures table in this MD&A presents 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 Summarized Cash Flow table in the Liquidity and Capital Resources section in this MD&A.

Reconciliation of Non-GAAP Measures

Three months ended September 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2012	Natural Gas Pipelines 2011	Oil Pipelines 2012	Oil Pipelines 2011	Energy 2012	Energy 2011	Corporate 2012	Corporate 2011	Total 2012	Total 2011
Comparable EBITDA	**660**	698	**177**	156	**267**	352	**(21)**	(18)	**1,083**	1,188
Depreciation and amortization	**(231)**	(231)	**(37)**	(38)	**(70)**	(65)	**(4)**	(3)	**(342)**	(337)
Comparable EBIT	**429**	467	**140**	118	**197**	287	**(25)**	(21)	**741**	851
Other Income Statement Items										
Comparable interest expense									**(253)**	(269)
Comparable interest income and other									**22**	(4)
Comparable income taxes									**(122)**	(137)
Net income attributable to non-controlling interests									**(23)**	(26)
Preferred share dividends									**(6)**	(6)
Comparable Earnings									**359**	409
Specific items (net of tax):										
Risk management activities[1]									**20**	(30)
Net Income Attributable to Common Shares									**379**	379

Three months ended September 30 *(unaudited) (millions of dollars)*	2012	2011
Comparable Interest Expense	**(253)**	(269)
Specific item:		
Risk management activities[1]	**-**	2
Interest Expense	**(253)**	(267)
Comparable Interest Income and Other	**22**	(4)
Specific item:		
Risk management activities[1]	**12**	(39)
Interest Income and Other	**34**	(43)
Comparable Income Taxes	**(122)**	(137)
Specific items:		
Income taxes attributable to risk management activities[1]	**(11)**	13
Income Taxes Expense	**(133)**	(124)

(1)

Three months ended September 30 *(unaudited)(millions of dollars)*	2012	2011
Risk Management Activities Gains/(Losses):		
Canadian Power	**11**	-
U.S. Power	**20**	(3)
Natural Gas Storage	**(12)**	(3)
Interest rate	**-**	2
Foreign exchange	**12**	(39)
Income taxes attributable to risk management activities	**(11)**	13
Risk Management Activities	**20**	(30)

Reconciliation of Non-GAAP Measures

Nine months ended September 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines **2012**	 2011	Oil Pipelines **2012**	 2011	Energy **2012**	 2011	Corporate **2012**	 2011	Total **2012**	 2011
Comparable EBITDA	**2,051**	2,159	**526**	408	**681**	914	**(65)**	(57)	**3,193**	3,424
Depreciation and amortization	**(697)**	(688)	**(109)**	(95)	**(215)**	(194)	**(11)**	(10)	**(1,032)**	(987)
Comparable EBIT	**1,354**	1,471	**417**	313	**466**	720	**(76)**	(67)	**2,161**	2,437
Other Income Statement Items										
Comparable interest expense									**(745)**	(770)
Comparable interest income and other									**66**	52
Comparable income taxes									**(350)**	(448)
Net income attributable to non-controlling interests									**(73)**	(79)
Preferred share dividends									**(17)**	(17)
Comparable Earnings									**1,042**	1,175
Specific items (net of tax):										
Sundance A PPA arbitration decision									**(15)**	-
Risk management activities[1]									**(4)**	(44)
Net Income Attributable to Common Shares									**1,023**	1,131

Nine months ended September 30 *(unaudited) (millions of dollars)*	**2012**	2011
Comparable Interest Expense	**(745)**	(770)
Specific item:		
Risk management activities[1]	**-**	2
Interest Expense	**(745)**	(768)
Comparable Interest Income and Other	**66**	52
Specific item:		
Risk management activities[1]	**4**	(40)
Interest Income and Other	**70**	12
Comparable Income Taxes	**(350)**	(448)
Specific items:		
Income taxes attributable to Sundance A PPA arbitration decision	**5**	-
Income taxes attributable to risk management activities[1]	**1**	21
Income Taxes Expense	**(344)**	(427)

(1)

Nine months ended September 30 *(unaudited)(millions of dollars)*	**2012**	2011
Risk Management Activities Gains/(Losses):		
Canadian Power	**10**	1
U.S. Power	**4**	(15)
Natural Gas Storage	**(23)**	(13)
Interest rate	**-**	2
Foreign exchange	**4**	(40)
Income taxes attributable to risk management activities	**1**	21
Risk Management Activities	**(4)**	(44)

Consolidated Results of Operations

Third Quarter Results

Comparable Earnings in third quarter 2012 were $359 million compared to $409 million for the same period in 2011. Comparable Earnings excluded net unrealized after-tax gains of $20 million ($31 million pre-tax) (2011 – losses of $30 million after tax ($43 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings decreased $50 million in third quarter 2012 compared to the same period in 2011 and reflected the following:

- decreased Canadian Natural Gas Pipelines Comparable net income primarily due to lower earnings from the Canadian Mainline which excluded incentive earnings and reflected a lower investment base;
- decreased U.S. and International Natural Gas Pipelines EBIT which primarily reflected lower revenue from ANR as well as the impact of capacity sold at lower rates on Great Lakes;
- increased Oil Pipelines Comparable EBIT which reflected higher revenues primarily due to higher contracted volumes and higher final fixed tolls for the Cushing Extension section of the Keystone Pipeline system which came into effect in July 2012;
- decreased Energy Comparable EBIT primarily due to the Sundance A power purchase arrangement (PPA) force majeure, lower Alberta PPA volumes, as well as a decrease in Equity Income from Bruce Power primarily due to a planned maintenance outage at Bruce A Unit 4, partially offset by higher contributions from Eastern Power due to higher Bécancour contractual earnings, and incremental earnings from Montagne-Sèche and phase one of Gros-Morne at Cartier Wind which were both placed in service in November 2011;
- increased Comparable Interest Income and Other due to higher realized gains in 2012 compared to losses in 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income, as well as gains in 2012 compared to losses in 2011 on translation of foreign denominated working capital balances; and
- decreased Comparable Income Taxes primarily due to lower pre-tax earnings in 2012 compared to 2011.

Comparable Earnings in the first nine months of 2012 were $1,042 million compared to $1,175 million for the same period in 2011. Comparable Earnings in the first nine months of 2012 excluded net unrealized after-tax losses of $4 million ($5 million pre-tax) (2011 – losses of $44 million after tax ($65 million pre-tax)) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in the first nine months of 2012 also excluded a negative after-tax charge of $15 million ($20 million pre-tax) following the July 2012 Sundance A PPA arbitration decision that was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011.

Comparable Earnings decreased $133 million for the first nine months of 2012 compared to the same period in 2011 and reflected the following:

- decreased Canadian Natural Gas Pipelines Comparable net income primarily due to lower earnings from the Canadian Mainline which excluded incentive earnings and reflected a lower investment base;

- decreased U.S. and International Natural Gas Pipelines EBIT which primarily reflected lower revenue resulting from uncontracted capacity and lower rates on Great Lakes as well as lower revenue from ANR, partially offset by incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011;

- increased Oil Pipelines Comparable EBIT as the Company commenced recording earnings from the Keystone Pipeline System in February 2011 and higher final fixed tolls for the Cushing Extension and the Wood River/Patoka sections which came into effect in July 2012 and May 2011, respectively, as well as higher volumes;

- decreased Energy Comparable EBIT primarily as a result of the Sundance A PPA force majeure, a decrease in Equity Income from Bruce Power primarily due to lower volumes resulting from increased planned outage days, lower realized power prices and reduced waterflows at U.S. hydro facilities and lower Natural Gas Storage revenue, partially offset by higher contributions from Eastern Power primarily due to higher Bécancour contractual earnings and incremental earnings from Montagne-Sèche and phase one of Gros-Morne which were placed in service in November 2011;

- decreased Comparable Interest Expense primarily due to lower interest expense on amounts due to TransCanada Corporation (TransCanada), partially offset by the negative impact of a stronger U.S. dollar on U.S. dollar-denominated interest, incremental interest expense on new debt issues in 2012 and 2011 and lower capitalized interest as assets under construction were placed in service;

- increased Comparable Interest Income and Other due to gains in 2012 compared to losses in 2011 on translation of foreign denominated working capital balances; and

- decreased Comparable Income Taxes primarily due to lower pre-tax earnings in 2012 compared to 2011.

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 exchange rates to convert a U.S. dollar to a Canadian dollar for the three and nine months ended September 30, 2012 were 0.99 and 1.00, respectively (2011 – 0.98 and 0.98, respectively).

Summary of Significant U.S. Dollar-Denominated Amounts

(unaudited) *(millions of U.S. dollars)*	Three months ended September 30		Nine months ended September 30	
	2012	2011	**2012**	2011
U.S. Natural Gas Pipelines Comparable EBIT(1)	**139**	166	**501**	578
U.S. Oil Pipelines Comparable EBIT(1)	**92**	78	**269**	210
U.S. Power Comparable EBIT(1)	**57**	63	**71**	160
Interest on U.S. dollar-denominated long-term debt	**(185)**	(187)	**(554)**	(549)
Capitalized interest on U.S. capital expenditures	**28**	21	**81**	93
U.S. non-controlling interests and other	**(44)**	(48)	**(140)**	(143)
	87	93	**228**	349

(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 $429 million and $1.4 billion in the three and nine months ended September 30, 2012, respectively, compared to $467 million and $1.5 billion, respectively, for the same periods in 2011.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended September 30 **2012**	2011	Nine months ended September 30 **2012**	2011
Canadian Natural Gas Pipelines				
Canadian Mainline	**247**	264	**744**	796
Alberta System	**194**	191	**554**	557
Foothills	**29**	31	**90**	96
Other (TQM[1], Ventures LP)	**7**	9	**22**	26
Canadian Natural Gas Pipelines Comparable EBITDA[2]	**477**	495	**1,410**	1,475
Depreciation and amortization[3]	**(179)**	(177)	**(533)**	(533)
Canadian Natural Gas Pipelines Comparable EBIT[2]	**298**	318	**877**	942
U.S. and International Natural Gas Pipelines (in U.S. dollars)				
ANR	**41**	55	**191**	233
GTN[4]	**28**	29	**84**	105
Great Lakes[5]	**16**	26	**51**	81
TC PipeLines, LP[1][6][7]	**19**	22	**57**	64
Other U.S. Pipelines (Iroquois[1], Bison[8], Portland[7][9])	**22**	18	**79**	80
International (Tamazunchale, Guadalajara[10], TransGas[1], Gas Pacifico/INNERGY[1])	**27**	27	**85**	52
General, administrative and support costs	**-**	(2)	**(4)**	(6)
Non-controlling interests[7]	**39**	45	**122**	127
U.S. and International Natural Gas Pipelines Comparable EBITDA[2]	**192**	220	**665**	736
Depreciation and amortization[3]	**(53)**	(54)	**(164)**	(158)
U.S. and International Natural Gas Pipelines Comparable EBIT[2]	**139**	166	**501**	578
Foreign exchange	**(1)**	(3)	**1**	(12)
U.S. and International Natural Gas Pipelines Comparable EBIT[2] (in Canadian dollars)	**138**	163	**502**	566
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[2]	**(7)**	(14)	**(25)**	(37)
Natural Gas Pipelines Comparable EBIT[2]	**429**	467	**1,354**	1,471
Summary:				
Natural Gas Pipelines Comparable EBITDA[2]	**660**	698	**2,051**	2,159
Depreciation and amortization[3]	**(231)**	(231)	**(697)**	(688)
Natural Gas Pipelines Comparable EBIT[2]	**429**	467	**1,354**	1,471

(1) Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect the Company's share of equity income from these investments.

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

(3) Does not include depreciation and amortization from equity investments.

(4) Results reflect TCPL's direct ownership interest of 75 per cent effective May 2011 and 100 per cent prior to that date.
(5) Represents TCPL's 53.6 per cent direct ownership interest.
(6) Effective May 2011, TCPL's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. As a result, the TC PipeLines, LP results include TCPL's decreased ownership in TC PipeLines, LP and TCPL's effective ownership through TC PipeLines, LP of 8.3 per cent of each of GTN and Bison since May 2011.
(7) Non-Controlling Interests reflects Comparable EBITDA for the portions of TC PipeLines, LP and Portland not owned by TCPL.
(8) Results reflect TCPL's direct ownership of 75 per cent of Bison effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison was placed in service.
(9) Represents TCPL's 61.7 per cent ownership interest.
(10) Includes Guadalajara's operations since June 2011 when the asset was placed in service.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited)	Three months ended September 30		Nine months ended September 30	
(millions of U.S. dollars)	**2012**	2011	**2012**	2011
Canadian Mainline	**47**	61	**140**	186
Alberta System	**53**	51	**153**	149
Foothills	**4**	6	**14**	18

Canadian Natural Gas Pipelines

Canadian Mainline's net income of $47 million and $140 million in the three and nine months ended September 30, 2012, respectively, decreased $14 million and $46 million from $61 million and $186 million in the same periods in 2011. Canadian Mainline's net income for the three and nine months ended September 30, 2011 included incentive earnings earned under an incentive arrangement in the five-year tolls settlement which expired December 31, 2011. In the absence of a National Energy Board (NEB) decision with respect to the 2012-2013 tolls application, which is not expected until late first quarter 2013, Canadian Mainline's 2012 year-to-date results continued to reflect the last NEB-approved rate of return on common equity of 8.08 per cent on deemed common equity of 40 per cent and excluded incentive earnings. In addition, Canadian Mainline's 2012 year-to-date net income decreased as a result of a lower average investment base compared to the prior year.

The Alberta System's net income in the three and nine months ended September 30, 2012, was $53 million and $153 million, respectively, compared to $51 million and $149 million for the same periods in 2011. The positive impact on 2012 net income from a higher average investment base was mostly offset by lower incentive earnings for the three and nine months ending September 30, 2012.

Canadian Mainline's Comparable EBITDA for the three and nine months ended September 30, 2012 of $247 million and $744 million, respectively, decreased $17 million and $52 million compared to the same periods in 2011. EBITDA from the Canadian Mainline reflects the net income variances discussed above as well as variances in depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis and, therefore, do not impact net income.

U.S. and International Natural Gas Pipelines

ANR's Comparable EBITDA in the three and nine months ended September 30, 2012 was US$41 million and US$191 million, respectively, compared to US$55 million and US$233 million for the same periods in 2011. The decreases were primarily due to lower transportation and storage revenues, higher operating and maintenance costs, lower incidental commodity sales and a second quarter 2011 settlement with a counterparty.

GTN's Comparable EBITDA in the three and nine months ended September 30, 2012 was US$28 million and US$84 million, respectively, compared to US$29 million and US$105 million for the same periods in 2011. The decrease in the nine months ended September 2012 compared to 2011 was primarily due to TCPL's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011.

Great Lakes' Comparable EBITDA in the three and nine months ended September 30, 2012 was US$16 million and US$51 million, respectively, compared to US$26 million and US$81 million for the same periods in 2011. The decreases were due to lower transportation revenue resulting from unsold long-haul winter capacity as well as summer capacity sold under short-term contracts at lower rates compared to the same period in 2011.

International Comparable EBITDA increased US$33 million for the nine months ended September 30, 2012 compared to the same period in 2011. The increase was primarily due to incremental earnings from the Guadalajara pipeline which was placed in service in June 2011.

Business Development

Natural Gas Pipelines' Business Development Comparable EBITDA loss from business development activities decreased $7 million and $12 million in the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. The decreases in business development costs were primarily related to reduced activity in 2012 for the Alaska Pipeline Project and 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.

Depreciation and Amortization

Natural Gas Pipelines' Depreciation and Amortization increased $9 million for the nine months ended September 30, 2012 compared to the same period in 2011. The increase was primarily due to incremental depreciation for the Guadalajara pipeline which was placed in service in June 2011.

Operating Statistics

Nine months ended September 30	Canadian Mainline[(1)]		Alberta System[(2)]		ANR[(3)]	
(unaudited)	**2012**	2011	**2012**	2011	**2012**	2011
Average investment base (millions of dollars)	**5,748**	6,250	**5,426**	5,017	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**1,167**	1,474	**2,697**	2,580	**1,199**	1,276
Average per day	**4.3**	5.4	**9.8**	9.5	**4.4**	4.7

(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, 2012 were 659 Bcf (2011 – 912 Bcf); average per day was 2.4 Bcf (2011 – 3.3 Bcf).

(2) Field receipt volumes for the Alberta System for the nine months ended September 30, 2012 were 2,747 Bcf (2011 – 2,643 Bcf); average per day was 10.0 Bcf (2011 – 9.7 Bcf).

(3) Under its current rates, which are approved by the FERC, ANR's results are not impacted by changes in its average investment base.

Oil Pipelines

Oil Pipelines Comparable EBIT for the three and nine months ended September 30, 2012 was $140 million and $417 million, respectively, compared to $118 million and $313 million for the three and eight month periods in 2011.

Oil Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended September 30 **2012**	2011	**Nine months ended September 30 2012**	Eight months ended September 30 2011
Keystone Pipeline System	**180**	157	**532**	410
Oil Pipeline Business Development	**(3)**	(1)	**(6)**	(2)
Oil Pipelines Comparable EBITDA[1]	**177**	156	**526**	408
Depreciation and amortization	**(37)**	(38)	**(109)**	(95)
Oil Pipelines Comparable EBIT[1]	**140**	118	**417**	313
Comparable EBIT denominated as follows:				
Canadian dollars	**48**	41	**147**	108
U.S. dollars	**92**	78	**269**	210
Foreign exchange	**-**	(1)	**1**	(5)
Oil Pipelines Comparable EBIT[1]	**140**	118	**417**	313

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

Keystone Pipeline System

The Keystone Pipeline System's Comparable EBITDA of $180 million and $532 million for the three and nine months ended September 30, 2012, respectively, increased $23 million and $122 million compared to the three and eight month periods in 2011. These increases reflected higher revenues primarily resulting from higher contracted volumes, the impact of higher final fixed tolls on the Cushing Extension and Wood River/Patoka sections of the system which came into effect in July 2012 and May 2011, respectively, and nine months of earnings being recorded in 2012 compared to eight months in 2011.

EBITDA from the Keystone Pipeline System is primarily generated from payments received under long-term commercial arrangements for committed capacity that are not dependant on actual throughput. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental EBITDA.

Depreciation and Amortization

Oil Pipelines Depreciation and Amortization increased $14 million for the nine months ended September 30, 2012 compared to the corresponding period in 2011 and primarily reflected nine months of operations compared to eight months in 2011 for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System.

Operating Statistics

(unaudited)	Three months ended September 30 **2012**	2011	**Nine months ended September 30 2012**	Eight months ended September 30 2011
Delivery volumes (thousands of barrels)[1]				
Total	**44,564**	39,696	**139,261**	92,329
Average per day	**484**	431	**508**	382

(1) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $197 million and $466 million for the three and nine months ended September 30, 2012, respectively, compared to $287 million and $720 million, respectively, for the same periods in 2011.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended September 30		Nine months ended September 30	
	2012	2011	**2012**	2011
Canadian Power				
Western Power[1][2]	**93**	150	**251**	341
Eastern Power[1][3]	**85**	72	**251**	215
Bruce Power[1]	**4**	47	**22**	111
General, administrative and support costs	**(12)**	(11)	**(34)**	(28)
Canadian Power Comparable EBITDA[4]	**170**	258	**490**	639
Depreciation and amortization[5]	**(38)**	(37)	**(117)**	(106)
Canadian Power Comparable EBIT[4]	**132**	221	**373**	533
U.S. Power (in U.S. dollars)				
Northeast Power	**100**	100	**195**	270
General, administrative and support costs	**(13)**	(10)	**(34)**	(29)
U.S. Power Comparable EBITDA[4]	**87**	90	**161**	241
Depreciation and amortization	**(30)**	(27)	**(90)**	(81)
U.S. Power Comparable EBIT[4]	**57**	63	**71**	160
Foreign exchange	**(1)**	-	**-**	(3)
U.S. Power Comparable EBIT[4] (in Canadian dollars)	**56**	63	**71**	157
Natural Gas Storage				
Alberta Storage[1]	**20**	12	**54**	62
General, administrative and support costs	**(3)**	(1)	**(7)**	(6)
Natural Gas Storage Comparable EBITDA[4]	**17**	11	**47**	56
Depreciation and amortization[5]	**(2)**	(2)	**(8)**	(9)
Natural Gas Storage Comparable EBIT[4]	**15**	9	**39**	47
Energy Business Development Comparable EBITDA and EBIT[1][4]	**(6)**	(6)	**(17)**	(17)
Energy Comparable EBIT[1][4]	**197**	287	**466**	720
Summary:				
Energy Comparable EBITDA[4]	**267**	352	**681**	914
Depreciation and amortization[5]	**(70)**	(65)	**(215)**	(194)
Energy Comparable EBIT[4]	**197**	287	**466**	720

(1) Results from ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta reflect the Company's share of equity income from these investments.
(2) Includes Coolidge effective May 2011.
(3) Includes Montagne-Sèche and phase one of Gros-Morne at Cartier Wind effective November 2011.
(4) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(5) Does not include depreciation and amortization of equity investments.

Canadian Power

Western and Eastern Canadian Power Comparable EBIT[1][2][3]

(unaudited) *(millions of dollars)*	Three months ended September 30 **2012**	2011	Nine months ended September 30 **2012**	2011
Revenue				
Western Power[2]	**152**	239	**482**	603
Eastern Power[3]	**108**	99	**309**	286
Other[4]	**19**	14	**66**	54
	279	352	**857**	943
Income from Equity Investments[5]	**28**	39	**45**	85
Commodity Purchases Resold				
Western Power	**(70)**	(103)	**(207)**	(279)
Other[6]	**(1)**	(4)	**(3)**	(13)
	(71)	(107)	**(210)**	(292)
Plant operating costs and other	**(58)**	(62)	**(160)**	(180)
Sundance A PPA arbitration decision[7]	**-**	-	**(30)**	-
General, administrative and support costs	**(12)**	(11)	**(34)**	(28)
Comparable EBITDA[1]	**166**	211	**468**	528
Depreciation and amortization[8]	**(38)**	(37)	**(117)**	(106)
Comparable EBIT[1]	**128**	174	**351**	422

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge effective May 2011.
(3) Includes Montagne-Sèche and phase one of Gros-Morne at Cartier Wind effective November 2011.
(4) Includes sales of excess natural gas purchased for generation and thermal carbon black.
(5) Results reflect equity income from TCPL's 50 per cent ownership interest in each of ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.
(6) Includes the cost of excess natural gas not used in operations.
(7) Refer to the Recent Developments section in this MD&A for more information regarding the Sundance A PPA arbitration decision.
(8) Excludes depreciation and amortization of equity investments.

Western and Eastern Canadian Power Operating Statistics[1]

(unaudited)	Three months ended September 30 **2012**	2011	Nine months ended September 30 **2012**	2011
Volumes (GWh)				
Generation				
Western Power[2]	**652**	630	**1,977**	1,937
Eastern Power[3]	**1,426**	1,014	**3,476**	2,862
Purchased				
Sundance A, B and Sheerness PPAs[4]	**1,555**	2,074	**4,889**	6,034
Other purchases	**-**	60	**46**	203
	3,633	3,778	**10,388**	11,036
Contracted				
Western Power[2]	**2,012**	2,182	**6,048**	6,256
Eastern Power[3]	**1,426**	1,014	**3,476**	2,862
Spot				
Western Power	**195**	582	**864**	1,918
	3,633	3,778	**10,388**	11,036
Plant Availability[5]				
Western Power[2][6]	**91%**	98%	**96%**	97%
Eastern Power[3][7]	**97%**	96%	**89%**	96%

(1) Includes TCPL's share of Equity Investments' volumes.
(2) Includes Coolidge effective May 2011.
(3) Includes Montagne-Sèche and phase one of Gros-Morne at Cartier Wind effective November 2011 and volumes related to TCPL's 50 per cent ownership interest in Portlands Energy.
(4) Includes TCPL's 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. No volumes were delivered under the Sundance A PPA in 2012 or 2011.
(5) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(6) Excludes facilities that provide power under PPAs.
(7) Bécancour has been excluded from the availability calculation as power generation has been suspended since 2008.

Western Power's Comparable EBITDA of $93 million and $251 million for the three and nine months ended September 30, 2012 decreased $57 million and $90 million compared to the same periods of 2011, respectively.

Throughout first quarter 2012, revenues and costs related to the Sundance A PPA had been recorded as though the outages of Units 1 and 2 were interruptions of supply. As a result of the Sundance A PPA arbitration decision received in July 2012, a $30 million charge, equivalent to the amount of pre-tax income recorded in first quarter 2012, was recorded in second quarter 2012. Because the plant is now in force majeure, revenues and costs will not be recorded until the plant returns to service. Western Power's Comparable EBITDA for the three and nine months ended September 30, 2011 included $48 million and $99 million, respectively, of accrued earnings related to the Sundance A PPA. Refer to the Recent Developments section in this MD&A for further discussion regarding the Sundance A PPA arbitration decision.

The decrease in Western Power's Comparable EBITDA in third quarter 2012 compared to 2011 was primarily due to the Sundance A PPA force majeure as well as lower volumes, partially offset by higher realized power prices.

The decrease in Western Power's Comparable EBITDA for the nine months ended September 30, 2012 compared to the same period in 2011 primarily reflected the Sundance A PPA force majeure as well as the impact of lower volumes sold, partially offset by the impact of lower fuel costs, incremental earnings from Coolidge which was placed in service in May 2011, and higher realized power prices.

Purchased volumes for the three and nine months ended September 30, 2012 decreased compared to the same periods in 2011 primarily due to decreased utilization of the Sundance B and Sheerness PPAs during periods of lower spot market power prices and higher plant outage days. Average spot market power prices decreased 18 per cent to $78 per megawatt hour (MWh) and 23 per cent to $59 per MWh for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. Despite the decrease in spot prices, Western Power earned a higher realized price per MWh for the three and nine months ended September 30, 2012 compared to the same periods in 2011 as a result of contracting activities.

Western Power's Power Revenue of $152 million and $482 million for the three and nine months ended September 30, 2012, respectively, decreased $87 million and $121 million, respectively, compared to the same periods in 2011 primarily due to the Sundance A PPA force majeure as well as lower purchased volumes, partially offset by higher realized power prices. Revenue for the nine months ended September 30, 2012 was also positively affected by Coolidge being placed in service in May 2011.

Western Power's Commodity Purchases Resold of $70 million and $207 million for the three and nine months ended September 30, 2012, respectively, decreased $33 million and $72 million, respectively, compared to the same periods in 2011 primarily due to the Sundance A PPA force majeure, as well as lower purchased volumes.

Eastern Power's Comparable EBITDA of $85 million and $251 million for the three and nine months ended September 30, 2012 increased $13 million and $36 million, respectively, compared to the same periods in 2011. Similarly, Eastern Power's Power Revenues of $108 million and $309 million for the three and nine months ended September 30, 2012 increased $9 million and $23 million, respectively, compared to the same periods in 2011. The increases were primarily due to higher Bécancour contractual earnings and incremental earnings from Montagne-Sèche and phase one of Gros-Morne at Cartier Wind, which were both placed in service in November 2011.

Income from Equity Investments of $28 million and $45 million, respectively, for the three and nine months ended September 30, 2012 decreased $11 million and $40 million, respectively, compared to the same periods in 2011 primarily due to lower earnings from the ASTC Power Partnership as a result of lower Sundance B PPA volumes and lower spot market power prices. Income from Equity Investments for the nine months ended September 30, 2012 was also impacted by lower earnings from Portlands Energy due to an unplanned outage in second quarter 2012.

Plant Operating Costs and Other, which includes fuel gas consumed in power generation, of $58 million and $160 million for the three and nine months ended September 30, 2012, respectively, decreased $4 million and $20 million compared to the same periods in 2011 primarily due to decreased natural gas fuel prices in 2012 compared to 2011.

Depreciation and Amortization for the nine months ended September 30, 2012 increased $11 million compared to the same period in 2011 primarily due to Montagne-Sèche and phase one of Gros-Morne at Cartier Wind and Coolidge being placed in service.

Approximately 91 per cent of Western Power sales volumes were sold under contract in third quarter 2012 compared to 81 per cent in third quarter 2011. To reduce its exposure to spot market prices in Alberta, as at

September 30, 2012, Western Power had entered into fixed-price power sales contracts to sell approximately 2,100 gigawatt hours (GWh) for the remainder of 2012 and 5,700 GWh for 2013.

Eastern Power's sales volumes were 100 per cent sold under contract and are expected to be fully contracted going forward.

Bruce Power Results

(TCPL's share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended September 30 **2012**	 2011	Nine months ended September 30 **2012**	 2011
Income/(Loss) from Equity Investments(1)				
Bruce A	**(39)**	16	**(95)**	48
Bruce B	**43**	31	**117**	63
	4	47	**22**	111
Comprised of:				
Revenues	**188**	221	**535**	636
Operating expenses	**(142)**	(135)	**(402)**	(417)
Depreciation and other	**(42)**	(39)	**(111)**	(108)
	4	47	**22**	111
Bruce Power – Other Information				
Plant availability(2)				
Bruce A	**59%**	97%	**55%**	98%
Bruce B	**99%**	94%	**94%**	88%
Combined Bruce Power	**87%**	95%	**76%**	91%
Planned outage days				
Bruce A	**60**	-	**213**	5
Bruce B	**-**	19	**46**	92
Unplanned outage days				
Bruce A	**7**	4	**7**	13
Bruce B	**2**	-	**25**	24
Sales volumes (GWh)(1)				
Bruce A	**943**	1,489	**2,585**	4,425
Bruce B	**2,241**	2,111	**6,197**	5,903
	3,184	3,600	**8,782**	10,328
Realized sales price per MWh				
Bruce A	**$68**	$66	**$68**	$66
Bruce B(3)	**$54**	$53	**$55**	$54
Combined Bruce Power	**$57**	$57	**$57**	$58

(1) Represents TCPL's 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.
(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.
(3) Includes revenue received under the floor price mechanism and from contract settlements as well as volumes and revenues associated with deemed generation.

TCPL's Equity Income from Bruce A decreased $55 million and $143 million for the three and nine months ended September 30, 2012, respectively, to losses of $39 million and $95 million compared to income of $16 million and $48 million for the same periods in 2011. The third quarter decrease was primarily due to lower volumes resulting from the Unit 4 planned outage which commenced on August 2, 2012. The decrease for the nine months ended September 30, 2012 also reflected the impact of the Unit 3 West Shift Plus planned outage which commenced in November 2011 and was completed in June 2012. Refer to the Recent Developments section in this MD&A for further discussion of these planned outages.

TCPL's Equity Income from Bruce B for the three and nine months ended September 30, 2012 of $43 million and $117 million, respectively, increased $12 million and $54 million compared to the same periods in 2011. The increases were primarily due to higher volumes and lower operating costs resulting from fewer planned outage days, lower lease expense and higher realized prices. Provisions in the Bruce B lease agreement with Ontario Power Generation provide for a reduction in annual lease expense if the annual average Ontario spot price for electricity is less than $30 per MWh. The average spot price has been below $30 per MWh for the first nine months of 2012, and this is expected to continue throughout 2012.

Under a contract with the Ontario Power Authority (OPA), all output from Bruce A in third quarter 2012 was sold at a fixed price of $68.23 per MWh (before recovery of fuel costs from the OPA) compared to $66.33 per MWh in third quarter 2011. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $51.62 per MWh in third quarter 2012 compared to $50.18 in third quarter 2011. 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 2012, TCPL currently expects spot prices to be less than the floor price for the year, therefore, no amounts recorded in revenues in 2012 are expected to be repaid.

The Unit 4 outage, which commenced on August 2, 2012, is expected to be completed in late fourth quarter 2012. There are no further outages planned at Bruce Power for the remainder of 2012. In October 2012, Bruce Power completed the refurbishment of Units 1 and 2 and returned Unit 1 to service on October 22, 2012. Bruce Power also synchronized Unit 2 to Ontario's electrical grid on October 16, 2012 and commercial operations for this unit are expected to commence shortly.

U.S. Power

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

(unaudited) *(millions of U.S. dollars)*	Three months ended September 30 **2012**	 2011	Nine months ended September 30 **2012**	 2011
Revenues				
Power(3)	**408**	336	**836**	931
Capacity	**75**	70	**181**	183
Other(4)	**5**	11	**29**	54
	488	417	**1,046**	1,168
Commodity purchases resold	**(268)**	(168)	**(548)**	(499)
Plant operating costs and other(4)	**(120)**	(149)	**(303)**	(399)
General, administrative and support costs	**(13)**	(10)	**(34)**	(29)
Comparable EBITDA(1)	**87**	90	**161**	241
Depreciation and amortization	**(30)**	(27)	**(90)**	(81)
Comparable EBIT(1)	**57**	63	**71**	160

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

(2) Certain comparative figures have been reclassified to conform with the financial statement presentation adopted for the current period.

(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, the activity level of which decreased in 2011.

U.S. Power Operating Statistics

(unaudited)	Three months ended September 30 2012	2011	Nine months ended September 30 2012	2011
Physical Sales Volumes (GWh)				
Supply				
Generation	**2,350**	2,137	**5,291**	5,369
Purchased	**3,601**	1,657	**6,858**	4,777
	5,951	3,794	**12,149**	10,146
Plant Availability[(1)]	**96%**	96%	**86%**	88%

(1) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.

U.S Power's Comparable EBITDA of US$87 million and US$161 million for the three and nine months ended September 30, 2012, respectively, decreased US$3 million and US$80 million compared to the same periods in 2011. The reductions were primarily due to lower realized power prices, higher load serving costs, and reduced water flows at the U.S. hydro facilities, partially offset by increased sales to wholesale, commercial and industrial customers.

Physical sales volumes for the three and nine months ended September 30, 2012 have increased compared to the same period in 2011 primarily due to higher purchased volumes to serve increased sales to wholesale, commercial and industrial customers in the PJM and New England markets. Generation volumes have been negatively impacted by reduced hydro volumes throughout 2012, however this was more than offset by higher generation volumes from other U.S. Power facilities in third quarter 2012.

U.S Power's Power Revenue of US$408 million for the three months ended September 30, 2012 increased US$72 million compared to the same period in 2011. The increase was primarily due to higher sales volumes to wholesale, commercial and industrial customers, partially offset by lower realized power prices. Power Revenue of US$836 million for the nine months ended September 30, 2012 decreased US$95 million compared to the same period in 2011 primarily due to lower realized power prices partially offset by increased sales volumes.

Capacity Revenue of US$75 million for the three months ended September 30, 2012 increased US$5 million compared to the same period in 2011 due to higher realized capacity prices in New York partially offset by lower New England capacity prices. Capacity Revenue of US$181 million for the nine months ended September 30, 2012, decreased US$2 million compared to the same period in 2011 as lower capacity prices in New England more than offset higher realized capacity prices in New York.

Commodity Purchases Resold of US$268 million and US$548 million for the three and nine months ended September 30, 2012, respectively, increased US$100 million and US$49 million compared to the same periods in 2011 due to higher volumes of physical power purchased for resale under power sales commitments to wholesale, commercial and industrial customers and higher load serving costs, partially offset by lower power prices.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of US$120 million and US$303 million for the three and nine months ended September 30, 2012, respectively, decreased US$29 million and US$96 million compared to the same periods in 2011 primarily due to lower natural gas fuel prices.

As at September 30, 2012, approximately 1,200 GWh or 53 per cent and 2,700 GWh or 35 per cent of U.S. Power's planned generation is contracted for the remainder of 2012 and for 2013, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA of $17 million for the three months ended September 30, 2012 increased $6 million compared to the same period in 2011 primarily due to higher realized natural gas storage price spreads and lower operating costs.

Natural Gas Storage's Comparable EBITDA of $47 million for the nine months ended September 30, 2012 decreased $9 million compared to the same period in 2011 primarily as a result of the impact of lower realized natural gas storage price spreads in the first quarter of 2012, partially offset by lower operating costs throughout the year.

Other Income Statement Items

Comparable Interest Expense[1]

(unaudited) *(millions of dollars)*	Three months ended September 30		Nine months ended September 30	
	2012	2011	**2012**	2011
Interest on long-term debt[2]				
Canadian dollar-denominated	**130**	121	**385**	365
U.S. dollar-denominated	**185**	187	**554**	549
Foreign exchange	**1**	(4)	**1**	(12)
	316	304	**940**	902
Other interest and amortization	**11**	31	**29**	99
Capitalized interest	**(74)**	(66)	**(224)**	(231)
Comparable Interest Expense[1]	**253**	269	**745**	770

(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 of $253 million and $745 million for the three and nine months ended September 30, 2012 decreased $16 million and $25 million, respectively, compared to the same periods in 2011. The decrease in interest expense for the nine months ended September 30, 2012 was primarily due to lower interest expense on amounts due to TransCanada and higher realized gains in 2012 compared to 2011 from derivatives used to manage the Company's exposure to rising interest rates and the impact of Canadian and U.S. dollar-denominated debt maturities in 2012 and 2011. The decrease was partially offset by incremental interest on debt issues of US$1.0 billion in August 2012, US$500 million in March 2012 and $750 million in November 2011, a TC PipeLines, LP debt issue of US$350 million in June 2011 and the negative impact of a stronger U.S. dollar on U.S. dollar-denominated interest, and lower capitalized interest for Keystone, Coolidge and Guadalajara as a result of placing these assets in service.

Comparable Interest Income and Other of $22 million and $66 million for the three and nine months ended September 30, 2012 increased $26 million and $14 million, respectively, compared to the same periods in 2011. The increase for the three months ended September 30, 2012 was primarily due to gains in 2012 compared to losses in 2011 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital balances. The increase for the nine months ended September 30, 2012 was primarily due to gains in 2012 compared to losses in 2011 on the translation of foreign denominated working capital balances.

Comparable Income Taxes were $122 million and $350 million in the three and nine months ended September 30, 2012, respectively, compared to $137 million and $448 million for the same periods in 2011. The decreases of $15 million and $98 million, respectively, were primarily due to lower pre-tax earnings in 2012 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 cash flow from operations, available cash balances and unutilized committed revolving bank lines of US$1.0 billion, US$300 million, US$1.0 billion and $2.0 billion, maturing in November 2012, February 2013, October 2013 and October 2017, respectively. These facilities also support the Company's three commercial paper programs. In addition, at September 30, 2012, TCPL's proportionate share of unutilized capacity on committed bank facilities at the Company's operated affiliates was $90 million with maturity dates in 2016. As at September 30, 2012, TCPL had remaining capacity of $1.25 billion and US$2.5 billion under its Canadian debt and U.S. debt shelf prospectuses, respectively. TCPL's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

Operating Activities

Funds Generated from Operations(1)

(unaudited) *(millions of dollars)*	Three months ended September 30 **2012**	2011	Nine months ended September 30 **2012**	2011
Cash Flows				
Funds generated from operations(1)	**860**	905	**2,448**	2,544
Decrease in operating working capital	**242**	102	**99**	205
Net cash provided by operations	**1,102**	1,007	**2,547**	2,749

(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 $95 million in the three months ended September 30, 2012 compared to the same period in 2011 primarily due to changes in working capital, partially offset by increased funding for pension plans and lower distributions received from equity investments. Net Cash Provided by Operations decreased $202 million in the nine months ended September 30, 2012 compared to the same periods in 2011 primarily due to lower earnings in addition to the previously mentioned third quarter changes.

As at September 30, 2012, TCPL's current assets were $3.6 billion and current liabilities were $4.8 billion resulting in a working capital deficiency of $1.2 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

In the three and nine months ended September 30, 2012, capital expenditures totalled $694 million and $1,555 million, respectively (2011– $505 million and $1,593 million, respectively) related to the expansions of the Keystone Pipeline System and the Alberta System. Equity investments of $144 million and $557 million for the three and nine months ended September 30, 2012, respectively (2011 - $213 million and $451 million, respectively) were primarily related to the Company's investment in the refurbishment and restart of Bruce Power Units 1 and 2 which were completed in October 2012 and the West Shift Plus life extension outage on Unit 3.

Financing Activities

In January 2012, TCPL issued 6.5 million common shares to TransCanada resulting in proceeds of $269 million.

In August 2012, the Company issued US$1.0 billion of senior notes maturing on August 1, 2022 and bearing interest at an annual rate of 2.5 per cent. In March 2012, the Company issued US$500 million of senior notes maturing on March 2, 2015 and bearing interest at an annual rate of 0.875 per cent. These notes were issued under the US$4.0 billion debt shelf prospectus filed in November 2011. The net proceeds of these offerings were used for general corporate purposes and to reduce short-term indebtedness.

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 TC PipeLines, LP.

Dividends

On October 29, 2012 TCPL's Board of Directors declared a quarterly dividend for the quarter ending December 31, 2012 in an aggregate amount equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on December 31, 2012. The dividend is payable on January 31, 2013. The Board of Directors also declared a dividend of $0.70 per share on TCPL's Series U and Series Y preferred shares for the period ending January 30, 2013 and February 1, 2013, respectively. The dividend for the Series U and Series Y preferred shares is payable on January 30, 2013 and February 1, 2013, respectively, to shareholders of record at the close of business on December 31, 2012.

Contractual Obligations

There have been no material changes, except for an increase in capital commitments of $1.4 billion, primarily related to the Gulf Coast Project and Keystone XL Pipeline, offset by the decreases to market-based commodity purchase commitments of approximately $1.3 billion, to TCPL's contractual obligations from December 31, 2011 to September 30, 2012, 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 2011 Annual Report.

Accounting Policies and Critical Accounting Estimates

Effective January 1, 2012, TCPL commenced reporting under U.S. GAAP as permitted. Comparative figures, which were previously presented in accordance with CGAAP, have been adjusted as necessary to be compliant with the Company's accounting policies under U.S. GAAP. The financial reporting impact of TCPL adopting U.S. GAAP is disclosed in Note 25 of TCPL's 2011 audited Consolidated Financial Statements included in TCPL's 2011 Annual Report. The accounting policies and critical accounting estimates applied are consistent with those outlined in TCPL's 2011 Annual Report, except as described below, which outlines the Company's significant accounting policies that have changed upon adoption of U.S. GAAP.

In preparing the 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.

Changes to Accounting Policies Upon Adoption of U.S. GAAP

Principles of Consolidation
The condensed consolidated financial statements include the accounts of TCPL and its subsidiaries. The Company consolidates its interests in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TCPL uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TCPL records its proportionate share of undivided interests in certain assets.

Inventories
Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Income Taxes
The Company uses the liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Employee Benefit and Other Plans
The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive Income/(Loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive Income/(Loss) (AOCI) over the average remaining service period of the active employees. For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains and losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities which are then amortized on a straight-line basis over the average remaining service life of active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Long-Term Debt Transaction Costs
The Company records long-term debt transaction costs as deferred assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

Guarantees
Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Changes in Accounting Policies for 2012

Fair Value Measurement
Effective January 1, 2012, the Company adopted the Accounting Standards Update (ASU) on fair value measurements as issued by the Financial Accounting Standards Board (FASB). Adoption of the ASU has resulted in an increase in the qualitative and quantitative disclosures regarding Level III measurements.

Intangibles – Goodwill and Other
Effective January 1, 2012, the Company adopted the ASU on testing goodwill for impairment as issued by the FASB. Adoption of the ASU has resulted in a change in the accounting policy related to testing goodwill for impairment, as the Company is now permitted under U.S. GAAP to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount as a basis for determining whether it is required to proceed to the two-step quantitative impairment test.

Future Accounting Changes

Balance Sheet Offsetting/Netting
In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting arrangement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosure regarding financial instruments which are subject to offsetting as described in this amendment.

Financial Instruments and Risk Management

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

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets and notes receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At September 30, 2012, there were no significant amounts past due or impaired.

At September 30, 2012, the Company had a credit risk concentration of $266 million due from a 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.

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, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $11.0 billion (US$11.2 billion) and a fair value of $14.4 billion (US$14.6 billion). At September 30, 2012, $60 million (December 31, 2011 - $79 million) was included in Other Current Assets, $96 million (December 31, 2011 - $66 million) was included in Intangibles and Other Assets, $6 million (December 31, 2011 - $15 million) was included in Accounts Payable and $18 million (December 31, 2011 - $41 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 self-sustaining foreign operations.

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

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

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**September 30, 2012** **Fair Value[(1)]**	 **Notional or Principal Amount**	December 31, 2011 Fair Value[(1)]	 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2019)[(2)]	**131**	**US 3,950**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2012)	**1**	**US 100**	(4)	US 725
	132	**US 4,050**	89	US 4,575

(1) Fair values equal carrying values.
(2) Consolidated Net Income in the three and nine months ended September 30, 2012 included net realized gains of $8 million and $22 million, respectively (2011 – gains of $8 million and $20 million, respectively) related to the interest component of cross-currency swap settlements.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**September 30, 2012** **Carrying Amount[(1)]**	 **Fair Value[(2)]**	December 31, 2011 Carrying Amount[(1)]	 Fair Value[(2)]
Financial Assets				
Cash and cash equivalents	**485**	**485**	629	629
Accounts receivable and other[(3)]	**1,137**	**1,193**	1,378	1,422
Due from TransCanada Corporation	**1,010**	**1,010**	750	750
Available-for-sale assets[(3)]	**32**	**32**	23	23
	2,664	**2,720**	2,780	2,824
Financial Liabilities[(4)]				
Notes payable	**1,470**	**1,470**	1,863	1,863
Accounts payable and deferred amounts[(5)]	**1,069**	**1,069**	1,330	1,330
Accrued interest	**366**	**366**	367	367
Long-term debt	**18,969**	**24,938**	18,659	23,757
Junior subordinated notes	**983**	**1,048**	1,016	1,027
	22,857	**28,891**	23,235	28,344

(1) Recorded at amortized cost, except for US$350 million (December 31, 2011 – US$350 million) of Long-Term Debt that is recorded at fair value. This debt which is recorded at fair value on a recurring basis is classified in Level II of the fair value category using the income approach based on interest rates from external data service providers.
(2) The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.
(3) At September 30, 2012, the Condensed Consolidated Balance Sheet included financial assets of $908 million (December 31, 2011 – $1.1 billion) in Accounts Receivable, $39 million (December 31, 2011 – $41 million) in Other Current Assets and $222 million (December 31, 2011 - $247 million) in Intangibles and Other Assets.
(4) Consolidated Net Income in the three and nine months ended September 30, 2012 included losses of $2 million and $14 million, respectively (2011 – losses of $7 million and $18 million, respectively) for fair value adjustments related to interest rate swap agreements on US$350 million (2011 – US$350 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(5) At September 30, 2012, the Condensed Consolidated Balance Sheet included financial liabilities of $967 million (December 31, 2011 – $1.2 billion) in Accounts Payable and $102 million (December 31, 2011 - $137 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, 2012 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading(1)				
Fair Values(2)				
Assets	**$168**	**$107**	**$7**	**$16**
Liabilities	**$(195)**	**$(126)**	**$(13)**	**$(16)**
Notional Values				
Volumes(3)				
Purchases	**31,717**	**99**	**-**	**-**
Sales	**32,700**	**73**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**620**
U.S. dollars	**-**	**-**	**US 1,255**	**US 200**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized gains/(losses) in the period(4)				
Three months ended September 30, 2012	**$1**	**$12**	**$13**	**-**
Nine months ended September 30, 2012	**$(17)**	**$2**	**$5**	**-**
Net realized (losses)/gains in the period(4)				
Three months ended September 30, 2012	**$4**	**$(4)**	**$6**	**-**
Nine months ended September 30, 2012	**$8**	**$(19)**	**$21**	**-**
Maturity dates	**2012-2016**	**2012-2016**	**2012-2013**	**2013-2016**
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(2)				
Assets	**$85**	**-**	**-**	**$13**
Liabilities	**$(130)**	**$(6)**	**$(41)**	**-**
Notional Values				
Volumes(3)				
Purchases	**17,745**	**3**	**-**	**-**
Sales	**7,467**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 42**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized gains/(losses) in the period(4)				
Three months ended September 30, 2012	**$(49)**	**$(7)**	**-**	**$2**
Nine months ended September 30, 2012	**$(101)**	**$(21)**	**-**	**$5**
Maturity dates	**2012-2018**	**2012-2013**	**2012-2014**	**2013-2015**

(1) All derivative financial instruments held for trading 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 derivative financial instruments held for trading used to purchase and sell power and natural gas are included net 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 $13 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2012 were $2 million and $6 million, respectively, and were included in Interest Expense. In the three and nine months ended September 30, 2012, 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, 2012, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

2011

(unaudited) *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2][3]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values[3]				
Volumes[4]				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US 1,269	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized gains/(losses) in the period[5]				
Three months ended September 30, 2011	$6	$(13)	$(41)	$1
Nine months ended September 30, 2011	$9	$(39)	$(41)	$1
Net realized gains/(losses) in the period[5]				
Three months ended September 30, 2011	$15	$(20)	$(7)	-
Nine months ended September 30, 2011	$20	$(61)	$26	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships[6][7]				
Fair Values[2][3]				
Assets	$16	$3	-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values[3]				
Volumes[4]				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US 73	US 600
Cross-currency	-	-	136/US 100	-
Net realized losses in the period[5]				
Three months ended September 30, 2011	$(56)	$(6)	-	$(4)
Nine months ended September 30, 2011	$(112)	$(14)	-	$(13)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

(1) All derivative financial instruments held for trading 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) As at December 31, 2011.

(4) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(5) Realized and unrealized gains and losses on derivative financial instruments held for trading used to purchase and sell power and natural gas are included net 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.

(6) 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 $13 million and a notional amount of US$350 million at December 31, 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.

(7) 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 where it was probable that the anticipated transaction would not occur. 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 2012**	December 31 2011
Current		
Other current assets	**302**	361
Accounts payable	**(340)**	(485)
Long term		
Intangibles and other assets	**250**	202
Deferred amounts	**(211)**	(349)

Derivatives in Cash Flow Hedging Relationships

The components of OCI related to derivatives in cash flow hedging relationships are as follows:

Three months ended September 30 *(unaudited)* *(millions of dollars, pre-tax)*	Cash Flow Hedges							
	Power		Natural Gas		Foreign Exchange		Interest	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**96**	(25)	**(3)**	(14)	**(5)**	13	**-**	(1)
Reclassification of gains and (losses) on derivative instruments from AOCI to Net Income (effective portion)	**54**	26	**15**	27	**-**	-	**4**	11
Gains on derivative instruments recognized in earnings (ineffective portion)	**5**	1	**1**	1	**-**	-	**-**	-

Nine months ended September 30 *(unaudited)* *(millions of dollars, pre-tax)*	Cash Flow Hedges Power **2012**	 2011	 Natural Gas **2012**	 2011	 Foreign Exchange **2012**	 2011	 Interest **2012**	 2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**74**	(128)	**(17)**	(39)	**(5)**	6	**-**	(1)
Reclassification of gains on derivative instruments from AOCI to Net Income (effective portion)	**129**	58	**43**	80	**-**	-	**14**	33
Gains on derivative instruments recognized in earnings (ineffective portion)	**6**	2	**-**	-	**-**	-	**-**	-

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at September 30, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $41 million (2011 - $77 million), for which the Company had provided collateral of nil (2011 - $6 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2012, the Company would have been required to provide collateral of $41 million (2011 - $71 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the 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 that the Company has the ability to access at the measurement date.

In Level II, the fair value of interest rate and foreign exchange derivative assets and liabilities is determined using the income approach. The fair value of power and gas commodity assets and liabilities is determined using the market approach. Under both approaches, valuation is based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Such inputs include published exchange rates, interest rates, interest rate swap curves, yield curves, and broker quotes from external data service providers. Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in the nine months ended September 30, 2012 and 2011.

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

Long-dated commodity transactions in certain markets where liquidity is low are included in Level III of the fair value hierarchy, as the related commodity prices are not readily observable. Long-term electricity prices are estimated using a third-party modelling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Inputs into the model include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Long-term prices are reviewed by management and the Board on a periodic basis. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas may result in a lower fair value measurement of contracts included in Level III.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
(unaudited) *(millions of dollars, pre-tax)*	**Sept 30 2012**	Dec 31 2011	**Sept 30 2012**	Dec 31 2011	**Sept 30 2012**	Dec 31 2011	**Sept 30 2012**	Dec 31 2011
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**29**	36	**-**	-	**29**	36
Foreign exchange contracts	**-**	-	**160**	141	**-**	-	**160**	141
Power commodity contracts	**-**	-	**242**	201	**9**	-	**251**	201
Gas commodity contracts	**90**	124	**17**	55	**-**	-	**107**	179
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(16)**	(23)	**-**	-	**(16)**	(23)
Foreign exchange contracts	**-**	-	**(75)**	(102)	**-**	-	**(75)**	(102)
Power commodity contracts	**-**	-	**(318)**	(454)	**(5)**	(15)	**(323)**	(469)
Gas commodity contacts	**(114)**	(208)	**(18)**	(26)	**-**	-	**(132)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**32**	23	**-**	-	**-**	-	**32**	23
	8	(61)	**21**	(172)	**4**	(15)	**33**	(248)

The following table presents the net change in the Level III fair value category:

	Derivatives[1]			
	Three months ended September 30		Nine months ended September 30	
(unaudited) *(millions of dollars, pre-tax)*	**2012**	2011	**2012**	2011
Balance at beginning of period	**7**	(30)	**(15)**	(8)
New contracts	**-**	-	**-**	1
Settlements	**-**	1	**(1)**	1
Transfers out of Level III	**(12)**	2	**(10)**	2
Total gains included in Net Income[2]	**7**	-	**8**	-
Total gains/(losses) included in OCI	**2**	10	**22**	(13)
Balance at end of period	**4**	(17)	**4**	(17)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) For the three and nine months ended September 31, 2012, the unrealized gains or losses included in Net Income attributed to derivatives that were still held at the reporting date was a loss of $1 million (2011 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $6 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at September 30, 2012.

Other Risks

Additional risks faced by the Company are discussed in the MD&A in TCPL's 2011 Annual Report. These risks remain substantially unchanged since December 31, 2011.

Controls and Procedures

As of September 30, 2012, 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, 2012.

During the quarter ended September 30, 2012, there have been no changes in TCPL's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

Outlook

Since the disclosure in TCPL's 2011 Annual Report, the Company's overall earnings outlook for 2012 will be negatively impacted by the Sundance A PPA arbitration decision received in July 2012 which is expected to result in the Company not recording earnings from the Sundance A PPA in 2012. In addition, reduced demand for natural gas and electricity due to unseasonably warm winter weather, combined with continued strong U.S. natural gas production, has resulted in historically high natural gas storage levels and low natural gas prices, which are having a negative impact on revenues in U.S. Pipelines as well as power prices in Canadian and U.S. Power. Delays in restarting the Bruce Power Units 1 and 2 as well as an expanded planned outage at Unit 4 have also reduced the 2012 earnings outlook. For further information on outlook, refer to the MD&A in TCPL's 2011 Annual Report.

Recent Developments

Natural Gas Pipelines

Canadian Pipelines

Canadian Mainline
2012-2013 Tolls Application
In 2011, TCPL filed a comprehensive tolls application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline and to set tolls for 2012 and 2013. The hearing with respect to this application began on June 4, 2012 with final arguments to be heard from TCPL and the intervenors beginning November 13, 2012. A final decision from the NEB on the application is not expected before late first quarter 2013.

As part of the Canadian Mainline hearing, TCPL filed an updated throughput forecast for 2013 through 2020. Based on natural gas prices being lower by approximately US$1.40 per million BTUs in 2010 dollars on an annual average basis compared to the previous forecast, the Western Mainline Receipts are expected to be lower, on average, by approximately one billion cubic feet (Bcf) per day over the forecasted period.

Marcellus Facilities Expansion

In May 2012, TCPL received NEB approval with respect to an application that was re-filed in November 2011 to construct new pipeline infrastructure to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin. Construction continues on the new pipeline facilities and it is expected that the Marcellus shale gas supply will begin moving to market as of November 1, 2012.

Mainline New Capacity Open Season

In response to requests for capacity to bring additional Marcellus shale gas volumes into Canada, TCPL held a new capacity open season that closed in May 2012 for firm transportation service on the integrated Canadian Mainline from Niagara and Chippawa as well as from other receipt points to all delivery points, including points east of Parkway. As a result of revised project timelines for the approval and construction of the necessary facilities, TCPL is in the process of amending the Precedent Agreements resulting from the open season to reflect a revised contract in-service date of November 2015. The ultimate facilities requirements associated with the Precedent Agreements are still being assessed.

Alberta System

Expansion Projects

In the first three quarters of 2012, TCPL continued to expand its Alberta System by completing and placing in service 12 separate pipeline projects at a total cost of approximately $680 million. This included the completion of the approximate $250 million Horn River project in May 2012 that extended the Alberta System into the Horn River shale play in British Columbia.

The NEB has approved additional Alberta System expansions totaling approximately $630 million, including the Leismer-Kettle River Crossover project, a 30 inch, 77 kilometre (km) pipeline which was approved in June 2012. This project has an estimated construction cost of $162 million and is intended to provide increased capacity to meet demand in Northeast Alberta. Approximately $340 million of projects are still awaiting NEB approval, including the Komie North project which would extend the Alberta System further into the Horn River area.

NGL Extraction Convention

In October 2012, the Alberta System withdrew its NEB application to implement the NGL Extraction Convention (NEXT) extraction rights model. Business circumstances have significantly changed since the model was developed that could negatively impact gas production. As a result, the application to implement the model was withdrawn.

Coastal GasLink Pipeline Project

TCPL has been selected by Shell Canada Limited (Shell) and its partners to design, build, own and operate the proposed Coastal GasLink Pipeline Project, an estimated $4 billion pipeline that will transport natural gas from the Montney gas-producing region near Dawson Creek, British Columbia (B.C.) to the recently announced LNG Canada liquefied natural gas (LNG) export facility near Kitimat, B.C. The LNG Canada project is a joint venture led by Shell, with partners Korea Gas Corporation, Mitsubishi Corporation and PetroChina Company Limited. The approximately 700 km pipeline is expected to have an initial capacity of more than 1.7 Bcf/d and be placed in service toward the end of the decade. A proposed contractual extension of the Alberta System using capacity on the Coastal GasLink pipeline, to a point near Vanderhoof, B.C., will allow TCPL to also offer gas transmission service to interconnecting natural gas pipelines serving the West Coast. TCPL expects to elicit interest in and commitments for such service through an open season process in early 2013 subject to the overall project schedule.

U.S. Pipelines

Northern Border

Northern Border filed with the Federal Energy Regulatory Commission (FERC) a settlement with its customers to modify its transportation rates beginning in January 2013. If approved by the FERC, the settlement will result in an 11 per cent reduction in rates relative to current rates, includes a three-year moratorium on filing rate cases or challenging the settlement rates and requires Northern Border to file for new rates no later than January 1, 2018. Although Northern Border's revenues will decrease beginning in January 2013, the settlement provides rate certainty for up to five years. Northern Border is 50 per cent owned by TC PipeLines LP and TCPL owns 33 per cent of the TC PipeLines LP units.

ANR

The FERC issued an Order in June 2012 approving the sale of the offshore assets by ANR to its affiliate TC Offshore LLC, a newly created wholly-owned subsidiary of ANR, and allowing TC Offshore LLC to operate these assets as a standalone interstate pipeline. The FERC issued two orders in September 2012 that facilitate the commercial start up of TC Offshore as a new interstate natural gas pipeline entity comprised of ANR's offshore assets and authorized the tariff services and rate structure for this new entity. TC Offshore LLC is expected to begin commercial operations on November 1, 2012.

Alaska Pipeline Project

The Alaska North Slope producers (ExxonMobil, ConocoPhillips and BP), along with TCPL through its participation in the Alaska Pipeline Project, have agreed on a work plan aimed at commercializing North Slope natural gas resources via an LNG option. In May 2012, TCPL received approval from the State of Alaska to curtail its activities on the Alaska/Alberta route and focus on the LNG alternative, thereby allowing TCPL to defer its obligation to file for a FERC certificate for the Alberta route beyond the original fall 2012 deadline. TCPL held an open season in September 2012 to solicit interest in the LNG option and the project received a number of non-binding expressions of interest from potential shippers from a broad range of industry sectors located in North America and Asia.

Mackenzie Gas Project

Project activities have been curtailed largely due to natural gas market conditions. TCPL's future funding obligations for the Aboriginal Pipeline Group during such curtailment are expected to be nominal.

Oil Pipelines

Keystone Pipeline System

In May 2012, TCPL filed revised fixed tolls for the Cushing Extension section of the Keystone Pipeline System with both the NEB and the FERC. The revised tolls, which reflect the final project costs of the Keystone Pipeline System, became effective July 1, 2012.

Gulf Coast Project

The Company announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Project has its own independent value to the marketplace and will be constructed as the stand-alone Gulf Coast Project, which is not part of the Presidential Permit process. The 36-inch pipeline, which will extend from Cushing, Oklahoma to the U.S. Gulf Coast, is expected to have an initial capacity of up to 700,000 barrels per day (bbl/d) with an ultimate capacity of 830,000 bbl/d. TCPL started construction in August 2012 and expects to place the Gulf Coast Project in service in late 2013. As of September 30, 2012, US$0.9 billion has been invested in the project. Included in the US$2.3 billion cost is US$300 million for the 76 km (47 mile) Houston Lateral pipeline that will transport crude oil to Houston refineries.

Keystone XL Pipeline

In May 2012, TCPL filed a Presidential Permit application (cross border permit) with the U.S. Department of State (DOS) for the Keystone XL Pipeline from the U.S./Canada border in Montana to Steele City, Nebraska. TCPL will supplement that application with an alternative route in Nebraska as soon as that route is selected.

The Company continues to work collaboratively with the Nebraska Department of Environmental Quality (NDEQ) to finalize an alternative route that avoids the Nebraska Sandhills. A proposed route submitted by TCPL in April 2012 has been modified in response to comments received from the NDEQ and the public. In September 2012, the Company submitted a Supplemental Environmental Report (SER) to the NDEQ for the preferred alternative route. The NDEQ has indicated that it will complete its review by the end of 2012. In addition to submitting a SER to the NDEQ, TCPL has provided an environmental report to the DOS. The environmental report is required as part of the DOS review of the Company's Presidential Permit application.

The approximate cost of the 36-inch line is US$5.3 billion and, subject to regulatory approvals, TCPL expects the Keystone XL Pipeline to be in service in late 2014 or early 2015. As of September 30, 2012, US$1.6 billion has been invested in this project.

Keystone Hardisty Terminal

In May 2012, TCPL announced that it had secured binding long-term commitments exceeding 500,000 bbl/d for the Keystone Hardisty Terminal. As a result of strong commercial support for the project, the Company has expanded the proposed two million barrel project to a 2.6 million barrel terminal located at Hardisty, Alberta. The Keystone Hardisty Terminal Project will provide new crude oil batch accumulation tankage and pipeline infrastructure for Western Canadian producers and access to the Keystone Pipeline System. The project is expected to be operational in late 2014 and cost approximately $275 million.

Northern Courier Pipeline

In August 2012, TCPL announced that it had been selected by Fort Hills Energy Limited Partnership to design, build, own and operate the proposed Northern Courier Pipeline Project. The project, with an estimated capital cost of $660 million, is a 90 km (54 mile) pipeline system that will transport bitumen and diluent between the Fort Hills mine site and the Voyageur Upgrader located north of Fort McMurray, Alberta.

Northern Courier Pipeline is fully subscribed under long-term contracts to service the Fort Hills Mine, which is jointly owned by Suncor Energy Inc, Total E&P Canada Ltd. and Teck Resources Limited and is operated by Suncor Energy Operating Inc. The Northern Courier Pipeline Project is conditional on and subject to the Fort Hills project receiving sanction by its co-owners and obtaining regulatory approval. TCPL expects to file its initial regulatory application in early 2013.

Grand Rapids

In October, TCPL announced that it has entered into binding agreements with Phoenix Energy Holdings Limited (Phoenix) to develop the Grand Rapids Pipelines project in Northern Alberta. TCPL and Phoenix will each own 50 per cent of the proposed $3 billion pipeline project that includes both a crude oil and a diluent line to transport volumes approximately 500 km (300 miles) between the producing area northwest of Fort McMurray and the Edmonton/ Heartland region. The Grand Rapids Pipeline system is expected to be in service by early 2017, subject to regulatory approvals, and will have the capacity to move up to 900,000 bbl/d of crude oil and 330,000 bbl/d of diluent. TCPL will operate the system and Phoenix has entered a long-term commitment to ship crude oil and diluent on the system.

Canadian Mainline Conversion
TCPL has determined a conversion of a portion of the Canadian Mainline natural gas pipeline system to crude oil service is both technically and economically feasible. Through a combination of converted natural gas pipeline and new construction, the proposed pipeline would deliver crude oil between Hardisty, Alberta and markets in Eastern Canada. The Company has begun soliciting input from stakeholders and prospective shippers to determine market acceptance of the proposed project.

Energy

Bruce Power
In October 2012, Bruce Power completed the refurbishment of Unit 1 and returned this unit to service on October 22, 2012. Bruce Power also synchronized Unit 2 to Ontario's electrical grid on October 16, 2012 and commercial operations for this unit are expected to commence shortly. Units 1 and 2 are expected to produce clean and reliable power for the province of Ontario until at least 2037. Following the return to service of both Units 1 and 2, Bruce Power will be capable of producing 6,200 megawatts (MW) of emission-free power.

The return to service of Units 1 and 2 had been delayed as a result of a May 2012 incident which occurred within the Unit 2 electrical generator on the non-nuclear side of the plant. Bruce Power's force majeure claim related to this incident was accepted by the OPA and Bruce Power continues to receive the contracted price for power generated at Bruce A.

In August 2012, Bruce Power continued to invest in its strategy to maximize the lives of its reactors by commencing an expanded outage investment program on Unit 4 in support of extending the life of the unit. The Unit 4 outage, expected to conclude in late fourth quarter 2012, will align the lifespan of Unit 4 to that of Unit 3. In June 2012, Bruce Power returned Unit 3 to service after completing the West Shift Plus life extension outage which commenced in November 2011 at a cost of approximately $300 million. This investment is expected to allow Unit 3 to produce low cost electricity until at least 2021.

Sundance A
In December 2010, Sundance Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta Corporation (TransAlta) in January 2011. In February 2011, TransAlta notified TCPL that it had determined it was uneconomic to repair Units 1 and 2 and that the Sundance A PPA should therefore be terminated.

TCPL disputed both the force majeure and economic destruction claims under the binding dispute resolution process provided in the PPA. The binding arbitration proceedings concluded during second quarter 2012 and a decision was received in July 2012. The arbitration panel determined that the PPA should not be terminated and ordered TransAlta to rebuild Units 1 and 2. The panel also limited TransAlta's force majeure claim from November 20, 2011 until such time that the units can reasonably be returned to service. According to the terms of the arbitration decision, TransAlta has an obligation under the PPA to exercise all reasonable efforts to mitigate or limit the effects of the force majeure. TransAlta announced that it expects the units to be returned to service in the fall of 2013.

The impact of this decision was recorded in the results for second quarter 2012. TCPL had recorded $188 million of EBITDA from the commencement of the outages in December 2010 to the end of March 2012 as it considered the outages to be an interruption of supply. As a result of the decision, the Company realized $138 million of this amount. The difference of $50 million was recorded as a charge to second quarter 2012 earnings. The net book value of the Sundance A PPA recorded in Intangibles and Other Assets remains fully recoverable. TCPL will not realize revenues from the Sundance A PPA until the units return to service.

Ravenswood

In 2011, TCPL and other parties jointly filed two formal complaints with the FERC regarding the manner in which the New York Independent System Operator (NYISO) has applied pricing rules for two new power plants that have recently begun service in the New York Zone J market. In June 2012, the FERC addressed the first complaint and indicated it will take steps to increase transparency and accountability with regard to future Mitigation Exemption Test (MET) decisions which determine whether a new facility is exempt from offering its capacity at a floor price.

In September 2012, the FERC granted an order on the second complaint. The FERC directed the NYISO to retest the two new facilities, making changes to several parameters that form the basis of the MET calculations. Based on the changes the FERC has ordered, the recalculation could result in one or both entrants having to offer their capacity at a floor price which TCPL anticipates will result in higher capacity auction prices in the future. The order is prospective and will not impact capacity prices for prior periods.

Ontario Solar

In late 2011, TCPL agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 megawatts, for approximately $470 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TCPL will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. TCPL expects the acquisitions of these two projects to occur in early 2013 once acceptance testing has been completed. TCPL anticipates the remaining projects will be placed in service and acquired in 2013 and 2014, subject to regulatory approvals.

Napanee Generating Station

In September 2012, TCPL, the Government of Ontario, the OPA and Ontario Power Generation announced that two Memorandums of Understanding (MOU) were executed authorizing TCPL to develop, construct, own and operate a new 900 MW facility at Ontario Power Generation's Lennox site in Eastern Ontario in the town of Greater Napanee. The Napanee Generating Station would act as a replacement facility for one that was planned and subsequently cancelled in the community of Oakville. Under the terms of the MOUs, TCPL will be reimbursed for approximately $250 million of verifiable costs, primarily for natural gas turbines at Oakville which will be deployed at Napanee. The Company will further invest approximately $1.0 billion in the replacement Napanee facility. Definitive contracts are expected to be executed by mid-December and include a 20-year Clean Energy Supply contract.

Cartier Wind

The 111 MW second phase of Gros-Morne is expected to be operational in November 2012. This will complete construction of the 590 MW Cartier Wind project in Quebec. All of the power produced by Cartier Wind is sold under 20-year PPAs to Hydro-Québec.

Bécancour

In June 2012, Hydro-Québec notified TCPL it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2013. Under the terms of the suspension agreement, 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 capacity payments under the agreement similar to those that would have been received under the normal course of operation while energy production and payments are suspended.

Share Information

In January 2012, TCPL issued 6.5 million common shares to TransCanada resulting in proceeds of $269 million. At October 25, 2012, TCPL had 738 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)(2)

	2012			2011				2010
(millions of dollars, except per share amounts)	**Third**	**Second**	**First**	Fourth	Third	Second	First	Fourth
Revenues	**2,126**	**1,847**	**1,945**	2,015	2,043	1,851	1,930	1,743
Net income attributable to controlling interests	**385**	**287**	**368**	377	385	353	410	270
Share Statistics								
Net Income per common share								
Basic and diluted	**$0.51**	**$0.38**	**$0.49**	$0.54	$0.56	$0.52	$0.60	$0.39

(1) The selected quarterly consolidated financial data has been prepared in accordance with U.S. GAAP and is presented in Canadian dollars.
(2) Certain comparative figures have been reclassified to conform with the financial statement presentation adopted for the current period.

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 Pipeline System, earnings are primarily generated by contractual arrangements for committed capacity that are not dependent on actual throughput. 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, hydrology, 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 2012, EBIT included net unrealized gains of $31 million pre-tax ($20 million after tax) from certain risk management activities.
- Second Quarter 2012, EBIT included a $50 million pre-tax ($37 million after tax) charge from the Sundance A PPA arbitration decision and net unrealized losses of $14 million pre-tax ($13 million after tax) from certain risk management activities.
- First Quarter 2012, EBIT included net unrealized losses of $22 million pre-tax ($11 million after tax) from certain risk management activities.
- Fourth Quarter 2011, EBIT included net unrealized gains of $13 million pre-tax ($11 million after tax) resulting from certain risk management activities.
- Third Quarter 2011, Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of $43 million pre-tax ($30 million after tax) resulting from 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 $3 million pre-tax ($2 million after tax) resulting from 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 the Keystone Pipeline System in February 2011. EBIT included net unrealized losses of $19 million pre-tax ($12 million after tax) resulting from 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 Aboriginal Pipeline Group for the Mackenzie Gas Project. 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 $46 million pre-tax ($29 million after tax) resulting from certain risk management activities.

Condensed Consolidated Statement of Income

(unaudited) *(millions of Canadian dollars)*	Three months ended September 30 **2012**	2011	Nine months ended September 30 **2012**	2011
Revenues				
Natural Gas Pipelines	**1,058**	1,036	**3,177**	3,107
Oil Pipelines	**259**	229	**769**	575
Energy	**809**	778	**1,972**	2,142
	2,126	2,043	**5,918**	5,824
Income from Equity Investments	**71**	127	**196**	328
Operating and Other Expenses				
Plant operating costs and other	**758**	717	**2,192**	1,973
Commodity purchases resold	**337**	271	**758**	782
Depreciation and amortization	**342**	337	**1,032**	987
	1,437	1,325	**3,982**	3,742
Financial Charges/(Income)				
Interest expense	**253**	267	**745**	768
Interest income and other	**(34)**	43	**(70)**	(12)
	219	310	**675**	756
Income before Income Taxes	**541**	535	**1,457**	1,654
Income Taxes Expense				
Current	**8**	45	**104**	185
Deferred	**125**	79	**240**	242
	133	124	**344**	427
Net Income	**408**	411	**1,113**	1,227
Net Income Attributable to Non-Controlling Interests	**23**	26	**73**	79
Net Income Attributable to Controlling Interests	**385**	385	**1,040**	1,148
Preferred Share Dividends	**6**	6	**17**	17
Net Income Attributable to Common Shares	**379**	379	**1,023**	1,131

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Comprehensive Income

(unaudited) *(millions of Canadian dollars)*	**Three months ended September 30** **2012**	 2011	Nine months ended September 30 **2012**	 2011
Net Income	**408**	411	**1,113**	1,227
Other Comprehensive Income/(Loss), Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(196)**	416	**(189)**	262
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	**99**	(213)	**76**	(141)
Change in fair value of derivative instruments designated as cash flow hedges[3]	**60**	(18)	**43**	(113)
Reclassification to Net Income of losses on derivative instruments designated as cash flow hedges[4]	**47**	44	**119**	114
Reclassification to Net Income of actuarial losses and prior service costs on pension and other post-retirement benefit plans[5]	**4**	2	**18**	7
Other Comprehensive (Loss)/Income of Equity Investments[6]	**(3)**	1	**(1)**	1
Other Comprehensive Income	**11**	232	**66**	130
Comprehensive Income	**419**	643	**1,179**	1,357
Comprehensive (Loss)/Income Attributable to Non-Controlling Interests	**(11)**	98	**42**	133
Comprehensive Income Attributable to Controlling Interests	**430**	545	**1,137**	1,224
Preferred Share Dividends	**6**	6	**17**	17
Comprehensive Income Attributable to Common Shares	**424**	539	**1,120**	1,207

(1) Net of income tax expense of $51 million and $48 million for the three and nine months ended September 30, 2012, respectively (2011 – recovery of $97 million and $57 million, respectively).

(2) Net of income tax expense of $34 million and $26 million for the three and nine months ended September 30, 2012, respectively (2011 – recovery of $78 million and $51 million, respectively).

(3) Net of income tax expense of $28 million and $9 million for the three and nine months ended September 30, 2012, respectively (2011 – recovery of $9 million and $49 million, respectively).

(4) Net of income tax expense of $26 million and $67 million for the three and nine months ended September 30, 2012, respectively (2011 – expense of $20 million and $57 million, respectively).

(5) Net of income tax expense of $2 million and recovery of $1 million for the three and nine months ended September 30, 2012, respectively (2011 – expense of $1 million and $3 million, respectively).

(6) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, gains and losses on derivative instruments designated as cash flow hedges, offset by change in gains and losses on derivative instruments designated as cash flow hedges, net of income tax recovery of $1 million and nil for the three and nine months ended September 30, 2012, respectively (2011 – recovery of $2 million and expense of $3 million, respectively).

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Cash Flows

(unaudited) *(millions of Canadian dollars)*	**Three months ended September 30** **2012**	2011	Nine months ended September 30 **2012**	2011
Cash Generated from Operations				
Net income	**408**	411	**1,113**	1,227
Depreciation and amortization	**342**	337	**1,032**	987
Deferred income taxes	**125**	79	**240**	242
Income from equity investments	**(71)**	(127)	**(196)**	(328)
Distributions received from equity investments	**95**	127	**252**	307
Employee future benefits expense (less than)/in excess of funding	**(23)**	6	**(11)**	4
Other	**(16)**	72	**18**	105
Decrease in operating working capital	**242**	102	**99**	205
Net cash provided by operations	**1,102**	1,007	**2,547**	2,749
Investing Activities				
Capital expenditures	**(694)**	(505)	**(1,555)**	(1,593)
Equity investments	**(144)**	(213)	**(557)**	(451)
Deferred amounts and other	**40**	93	**82**	133
Net cash used in investing activities	**(798)**	(625)	**(2,030)**	(1,911)
Financing Activities				
Dividends on common and preferred shares	**(315)**	(301)	**(932)**	(884)
Distributions paid to non-controlling interests	**(27)**	(27)	**(84)**	(70)
Advances from/(to) parent, net	**10**	(10)	**(260)**	197
Notes payable (repaid)/issued, net	**(930)**	154	**(341)**	(257)
Long-term debt issued, net of issue costs	**995**	54	**1,488**	573
Reduction of long-term debt	**(12)**	(206)	**(782)**	(946)
Common shares issued	**-**	-	**269**	-
Partnership units of subsidiary issued, net of costs	**-**	-	**-**	321
Net cash used in financing activities	**(279)**	(336)	**(642)**	(1,066)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(14)**	27	**(19)**	12
Increase/(Decrease) in Cash and Cash Equivalents	**11**	73	**(144)**	(216)
Cash and Cash Equivalents				
Beginning of period	**474**	359	**629**	648
Cash and Cash Equivalents				
End of period	**485**	432	**485**	432

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Balance Sheet

(unaudited) *(millions of Canadian dollars)*	**September 30 2012**	December 31 2011
ASSETS		
Current Assets		
Cash and cash equivalents	**485**	629
Accounts receivable	**908**	1,113
Due from TransCanada Corporation	**1,010**	750
Inventories	**214**	248
Other	**967**	1,104
	3,584	3,844
Plant, Property and Equipment, net of accumulated depreciation of $16,259 and $15,406, respectively	**32,379**	32,467
Equity Investments	**5,520**	5,077
Goodwill	**3,419**	3,534
Regulatory Assets	**1,629**	1,684
Intangibles and Other Assets	**1,437**	1,460
	47,968	48,066
LIABILITIES		
Current Liabilities		
Notes payable	**1,470**	1,863
Accounts payable	**1,872**	2,336
Accrued interest	**366**	367
Current portion of long-term debt	**1,070**	935
	4,778	5,501
Regulatory Liabilities	**321**	297
Deferred Amounts	**706**	929
Deferred Income Tax Liabilities	**3,858**	3,591
Long-Term Debt	**17,899**	17,724
Junior Subordinated Notes	**983**	1,016
	28,545	29,058
EQUITY		
Common shares, no par value	**14,306**	14,037
Issued and outstanding: September 30, 2012 - 738 million shares December 31, 2011 - 732 million shares		
Preferred shares	**389**	389
Additional paid-in capital	**398**	394
Retained earnings	**4,652**	4,561
Accumulated other comprehensive loss	**(1,352)**	(1,449)
Controlling Interests	**18,393**	17,932
Non-controlling interests	**1,030**	1,076
Equity	**19,423**	19,008
	47,968	48,066

Contingencies and Guarantees (Note 9)

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of Canadian dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at December 31, 2011	**(643)**	**(281)**	**(525)**	**(1,449)**
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(158)**	**-**	**-**	**(158)**
Change in fair value of derivative instruments to hedge net investments in foreign operations[2]	**76**	**-**	**-**	**76**
Change in fair value of derivative instruments designated as cash flow hedges[3]	**-**	**43**	**-**	**43**
Reclassification to Net Income of losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][5]	**-**	**119**	**-**	**119**
Reclassification of actuarial losses and prior service costs on pension and other post-retirement benefit plans[6]	**-**	**-**	**18**	**18**
Other Comprehensive (Loss)/Income of Equity Investments [7]	**-**	**(12)**	**11**	**(1)**
Balance at September 30, 2012	**(725)**	**(131)**	**(496)**	**(1,352)**

(unaudited) *(millions of Canadian dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at December 31, 2010	(683)	(194)	(366)	(1,243)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	216	-	-	216
Change in fair value of derivative instruments to hedge net investments in foreign operations[2]	(141)	-	-	(141)
Change in fair value of derivative instruments designated as cash flow hedges[3]	-	(113)	-	(113)
Reclassification to Net Income of losses on derivative instruments designated as cash flow hedges[4][5]	-	106	-	106
Reclassification of actuarial losses and prior service costs on pension and other post-retirement benefit plans[6]	-	-	7	7
Other Comprehensive (Loss)/Income of Equity Investments [7]	-	(7)	8	1
Balance at September 30, 2011	(608)	(208)	(351)	(1,167)

(1) Net of income tax expense of $48 million and non-controlling interest losses of $31 million for the nine months ended September 30, 2012 (2011 – recovery of $57 million; gain of $46 million).

(2) Net of income tax expense of $26 million for the nine months ended September 30, 2012 (2011 – recovery of $51 million).

(3) Net of income tax expense of $9 million for the nine months ended September 30, 2012 (2011 – recovery of $49 million).

(4) Net of income tax expense of $67 million and non-controlling interest losses of nil for the nine months ended September 30, 2012 (2011 – expense of $57 million; gain of $8 million).

(5) Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net Income in the next 12 months are estimated to be $56 million ($31 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.

(6) Net of income tax recovery of $1 million for the nine months ended September 30, 2012 (2011 – expense of $3 million).

(7) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges, partially offset by changes in gains and losses on derivative instruments designated as cash flow hedges, net of income tax expense of nil for the nine months ended September 30, 2012 (2011 – nil).

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Equity

(unaudited) *(millions of Canadian dollars)*	Nine months ended September 30 **2012**	 2011
Common Shares		
Balance at beginning of period	**14,037**	11,636
Proceeds from common shares issued	**269**	-
Balance at end of period	**14,306**	11,636
Preferred Shares		
Balance at beginning and end of period	**389**	389
Additional Paid-In Capital		
Balance at beginning of period	**394**	359
Other	**4**	4
Dilution gain from TC PipeLines, LP units issued	**-**	30
Balance at end of period	**398**	393
Retained Earnings		
Balance at beginning of period	**4,561**	4,227
Net income attributable to controlling interests	**1,040**	1,148
Common share dividends	**(932)**	(886)
Preferred share dividends	**(17)**	(17)
Balance at end of period	**4,652**	4,472
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,449)**	(1,243)
Other comprehensive income	**97**	76
Balance at end of period	**(1,352)**	(1,167)
Equity Attributable to Controlling Interests	**18,393**	15,723
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,076**	768
Net income attributable to non-controlling interests	**73**	79
Other comprehensive (loss)/income attributable to non-controlling interests	**(31)**	54
Sale of TC PipeLines, LP units		
Proceeds, net of issue costs	**-**	321
Decrease in TCPL's ownership	**-**	(50)
Distributions to non-controlling interests	**(84)**	(78)
Other	**(4)**	13
Balance at end of period	**1,030**	1,107
Total Equity	**19,423**	16,830

See accompanying notes to the condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These condensed consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared by management in accordance with United States generally accepted accounting principles (U.S. GAAP). Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook (CGAAP), have been adjusted as necessary to be compliant with the Company's accounting policies under U.S. GAAP. The amounts adjusted for U.S. GAAP presented in these condensed consolidated financial statements for the three and nine months ended September 30, 2011 are the same as those that have been previously reported in the Company's September 30, 2011 Reconciliation to U.S. GAAP. The amounts adjusted for U.S. GAAP at December 31, 2011 are the same as those reported in Note 25 of TCPL's 2011 audited Consolidated Financial Statements included in TCPL's 2011 Annual Report. The accounting policies and critical accounting estimates applied are consistent with those outlined in TCPL's 2011 Annual Report, except as described in Note 2, which outlines the Company's significant accounting policies that have changed upon adoption of U.S. GAAP. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TCPL's 2011 Annual Report.

These condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect the financial position and results of operations for the respective periods. These condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2011 audited Consolidated Financial Statements included in TCPL's 2011 Annual Report. Certain comparative figures have been reclassified to conform with the financial statement presentation adopted for the current period.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's Natural Gas Pipeline segment due to seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Energy segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

Use of Estimates and Judgements

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 condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies.

2. Changes in Accounting Policies

Changes to Accounting Policies Upon Adoption of U.S. GAAP

Principles of Consolidation
The condensed consolidated financial statements include the accounts of TCPL and its subsidiaries. The Company consolidates its interests in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TCPL uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TCPL records its proportionate share of undivided interests in certain assets.

Inventories
Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Income Taxes
The Company uses the liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Employee Benefit and Other Plans
The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive Income/(Loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive Income/(Loss) (AOCI) over the average remaining service period of the active employees. For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains and losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the average remaining service life of active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Long-Term Debt Transaction Costs
The Company records long-term debt transaction costs as deferred assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

Guarantees
Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Changes in Accounting Policies for 2012

Fair Value Measurement
Effective January 1, 2012, the Company adopted the Accounting Standards Update (ASU) on fair value measurements as issued by the Financial Accounting Standards Board (FASB). Adoption of the ASU has resulted in an increase in the qualitative and quantitative disclosures regarding Level III measurements.

Intangibles – Goodwill and Other
Effective January 1, 2012, the Company adopted the ASU on testing goodwill for impairment as issued by the FASB. Adoption of the ASU has resulted in a change in the accounting policy related to testing goodwill for impairment, as the Company is now permitted under U.S. GAAP to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount as a basis for determining whether it is required to proceed to the two-step quantitative impairment test.

Future Accounting Changes

Balance Sheet Offsetting/Netting
In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting arrangement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosure regarding financial instruments which are subject to offsetting as described in this amendment.

3. Segmented Information

Three months ended September 30 *(unaudited)* *(millions of Canadian dollars)*	Natural Gas Pipelines 2012	Natural Gas Pipelines 2011	Oil Pipelines 2012	Oil Pipelines 2011	Energy 2012	Energy 2011	Corporate 2012	Corporate 2011	Total 2012	Total 2011
Revenues	**1,058**	1,036	**259**	229	**809**	778	**-**	-	**2,126**	2,043
Income from equity investments	**37**	39	**-**	-	**34**	88	**-**	-	**71**	127
Plant operating costs and other	**(435)**	(376)	**(82)**	(73)	**(220)**	(250)	**(21)**	(18)	**(758)**	(717)
Commodity purchases resold	**-**	-	**-**	-	**(337)**	(271)	**-**	-	**(337)**	(271)
Depreciation and amortization	**(231)**	(231)	**(37)**	(38)	**(70)**	(65)	**(4)**	(3)	**(342)**	(337)
	429	468	**140**	118	**216**	280	**(25)**	(21)	**760**	845
Interest expense									**(253)**	(267)
Interest income and other									**34**	(43)
Income before Income Taxes									**541**	535
Income taxes expense									**(133)**	(124)
Net Income									**408**	411
Net Income Attributable to Non-Controlling Interests									**(23)**	(26)
Net Income Attributable to Controlling Interests									**385**	385
Preferred Share Dividends									**(6)**	(6)
Net Income Attributable to Common Shares									**379**	379

Nine months ended September 30 *(unaudited)* *(millions of Canadian dollars)*	Natural Gas Pipelines 2012	Natural Gas Pipelines 2011	Oil Pipelines[1] 2012	Oil Pipelines[1] 2011	Energy 2012	Energy 2011	Corporate 2012	Corporate 2011	Total 2012	Total 2011
Revenues	**3,177**	3,107	**769**	575	**1,972**	2,142	**-**	-	**5,918**	5,824
Income from equity investments	**120**	117	**-**	-	**76**	211	**-**	-	**196**	328
Plant operating costs and other	**(1,246)**	(1,064)	**(243)**	(167)	**(638)**	(685)	**(65)**	(57)	**(2,192)**	(1,973)
Commodity purchases resold	**-**	-	**-**	-	**(758)**	(782)	**-**	-	**(758)**	(782)
Depreciation and amortization	**(697)**	(688)	**(109)**	(95)	**(215)**	(194)	**(11)**	(10)	**(1,032)**	(987)
	1,354	1,472	**417**	313	**437**	692	**(76)**	(67)	**2,132**	2,410
Interest expense									**(745)**	(768)
Interest income and other									**70**	12
Income before Income Taxes									**1,457**	1,654
Income taxes expense									**(344)**	(427)
Net Income									**1,113**	1,227
Net Income Attributable to Non-Controlling Interests									**(73)**	(79)
Net Income Attributable to Controlling Interests									**1,040**	1,148
Preferred Share Dividends									**(17)**	(17)
Net Income Attributable to Common Shares									**1,023**	1,131

(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 Canadian dollars)*	**September 30, 2012**	December 31, 2011
Natural Gas Pipelines	**22,862**	23,161
Oil Pipelines	**9,628**	9,440
Energy	**13,223**	13,269
Corporate	**2,255**	2,196
	47,968	48,066

4. Income Taxes

At September 30, 2012, the total unrecognized tax benefit of uncertain tax positions was approximately $46 million (December 31, 2011 - $48 million). TCPL recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the three and nine months ended September 30, 2012 is a reversal of interest expense of $2 million and $1 million, respectively, and nil for penalties (2011 – reversal of interest expense of $11 million and $13 million, respectively, and nil for penalties). At September 30, 2012, the Company had $6 million accrued for interest expense and nil accrued for penalties (December 31, 2011 - $7 million accrued for interest expense and nil accrued for penalties).

The effective tax rates for the nine-month periods ended September 30, 2012 and 2011 were 23.6 per cent and 25.8 per cent, respectively. The lower effective tax rate in 2012 was a result of a reduction in the Canadian statutory tax rate, and changes in the proportion of income earned between Canadian and foreign jurisdictions.

TCPL expects the enactment of certain Canadian Federal tax legislation in the next twelve months which is expected to result in a favourable income tax adjustment of approximately $25 million. Otherwise, subject to the results of audit examinations by taxation authorities and other legislative amendments, TCPL does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

5. Long-Term Debt

In the three and nine months ended September 30, 2012, the Company capitalized interest related to capital projects of $74 million and $224 million, respectively (2011 - $66 million and $231 million, respectively).

In January 2012, TransCanada PipeLine USA Ltd. repaid the remaining principal of US$500 million on its five-year term loan.

In March 2012, TCPL issued US$500 million of 0.875 per cent senior notes due in 2015.

In May 2012, TCPL retired US$200 million of 8.625 per cent senior notes.

In August 2012, TCPL issued US$1.0 billion of 2.5 per cent senior notes due in 2022.

6. Common Shares

In January 2012, TCPL issued 6.5 million common shares to TransCanada Corporation resulting in proceeds of $269 million.

7. Employee Post-Retirement Benefits

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

	Three months ended September 30				Nine months ended September 30			
(unaudited)	Pension Benefit Plans		Other Post-retirement Benefit Plans		Pension Benefit Plans		Other Post-retirement Benefit Plans	
(millions of Canadian dollars)	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Service cost	**16**	14	**1**	-	**49**	41	**2**	1
Interest cost	**24**	23	**2**	2	**71**	68	**6**	6
Expected return on plan assets	**(28)**	(29)	**-**	-	**(85)**	(85)	**(1)**	(1)
Amortization of actuarial loss	**5**	3	**-**	-	**14**	8	**1**	1
Amortization of past service cost	**-**	-	**-**	-	**1**	1	**-**	-
Amortization of regulatory asset	**5**	3	**-**	-	**15**	10	**-**	-
Amortization of transitional obligation related to regulated business	**-**	-	**1**	-	**-**	-	**2**	1
Net Benefit Cost Recognized	**22**	14	**4**	2	**65**	43	**10**	8

8. Financial Instruments and Risk Management

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets and notes receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At September 30, 2012, there were no significant amounts past due or impaired.

At September 30, 2012, the Company had a credit risk concentration of $266 million due from a 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.

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, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $11.0 billion (US$11.2 billion) and a fair value of $14.4 billion (US$14.6 billion). At September 30, 2012, $60 million (December 31, 2011 - $79 million) was included in Other Current Assets, $96 million (December 31, 2011 - $66 million) was included in Intangibles and Other Assets, $6 million (December 31, 2011 - $15 million) was included in Accounts Payable and $18 million (December 31, 2011 - $41 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 self-sustaining foreign operations.

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

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

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**September 30, 2012** Fair Value(1)	Notional or Principal Amount	December 31, 2011 Fair Value(1)	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2019)(2)	**131**	**US 3,950**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2012)	**1**	**US 100**	(4)	US 725
	132	**US 4,050**	89	US 4,575

(1) Fair values equal carrying values.

(2) Consolidated Net Income in the three and nine months ended September 30, 2012 included net realized gains of $8 million and $22 million, respectively (2011 – gains of $8 million and $20 million, respectively) related to the interest component of cross-currency swap settlements.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**September 30, 2012** Carrying Amount(1)	Fair Value(2)	December 31, 2011 Carrying Amount(1)	Fair Value(2)
Financial Assets				
Cash and cash equivalents	**485**	**485**	629	629
Accounts receivable and other(3)	**1,137**	**1,193**	1,378	1,422
Due from TransCanada Corporation	**1,010**	**1,010**	750	750
Available-for-sale assets(3)	**32**	**32**	23	23
	2,664	**2,720**	2,780	2,824
Financial Liabilities(4)				
Notes payable	**1,470**	**1,470**	1,863	1,863
Accounts payable and deferred amounts(5)	**1,069**	**1,069**	1,330	1,330
Accrued interest	**366**	**366**	367	367
Long-term debt	**18,969**	**24,938**	18,659	23,757
Junior subordinated notes	**983**	**1,048**	1,016	1,027
	22,857	**28,891**	23,235	28,344

(1) Recorded at amortized cost, except for US$350 million (December 31, 2011 – US$350 million) of Long-Term Debt that is recorded at fair value. This debt which is recorded at fair value on a recurring basis is classified in Level II of the fair value category using the income approach based on interest rates from external data service providers.

(2) The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

(3) At September 30, 2012, the Condensed Consolidated Balance Sheet included financial assets of $908 million (December 31, 2011 – $1.1 billion) in Accounts Receivable, $39 million (December 31, 2011 – $41 million) in Other Current Assets and $222 million (December 31, 2011 - $247 million) in Intangibles and Other Assets.

(4) Consolidated Net Income in the three and nine months ended September 30, 2012 included losses of $2 million and $14 million, respectively (2011 – losses of $7 million and $18 million, respectively) for fair value adjustments related to interest rate swap agreements on US$350 million (2011 – US$350 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(5) At September 30, 2012, the Condensed Consolidated Balance Sheet included financial liabilities of $967 million (December 31, 2011 – $1.2 billion) in Accounts Payable and $102 million (December 31, 2011 - $137 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, 2012 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$168**	**$107**	**$7**	**$16**
Liabilities	**$(195)**	**$(126)**	**$(13)**	**$(16)**
Notional Values				
Volumes[3]				
Purchases	**31,717**	**99**	**-**	**-**
Sales	**32,700**	**73**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**620**
U.S. dollars	**-**	**-**	**US 1,255**	**US 200**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized gains/(losses) in the period[4]				
Three months ended September 30, 2012	**$1**	**$12**	**$13**	**-**
Nine months ended September 30, 2012	**$(17)**	**$2**	**$5**	**-**
Net realized (losses)/gains in the period[4]				
Three months ended September 30, 2012	**$4**	**$(4)**	**$6**	**-**
Nine months ended September 30, 2012	**$8**	**$(19)**	**$21**	**-**
Maturity dates	**2012-2016**	**2012-2016**	**2012-2013**	**2013-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$85**	**-**	**-**	**$13**
Liabilities	**$(130)**	**$(6)**	**$(41)**	**-**
Notional Values				
Volumes[3]				
Purchases	**17,745**	**3**	**-**	**-**
Sales	**7,467**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 42**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized gains/(losses) in the period[4]				
Three months ended September 30, 2012	**$(49)**	**$(7)**	**-**	**$2**
Nine months ended September 30, 2012	**$(101)**	**$(21)**	**-**	**$5**
Maturity dates	**2012-2018**	**2012-2013**	**2012-2014**	**2013-2015**

(1) All derivative financial instruments held for trading 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 derivative financial instruments held for trading used to purchase and sell power and natural gas are included net 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 $13 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2012 were $2 million and $6 million, respectively, and were included in Interest Expense. In the three and nine months ended September 30, 2012, 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, 2012, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

2011

(unaudited) *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2][3]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values[3]				
Volumes[4]				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US 1,269	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized gains/(losses) in the period[5]				
Three months ended September 30, 2011	$6	$(13)	$(41)	$1
Nine months ended September 30, 2011	$9	$(39)	$(41)	$1
Net realized gains/(losses) in the period[5]				
Three months ended September 30, 2011	$15	$(20)	$(7)	-
Nine months ended September 30, 2011	$20	$(61)	$26	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships[6][7]				
Fair Values[2][3]				
Assets	$16	$3	-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values[3]				
Volumes[4]				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US 73	US 600
Cross-currency	-	-	136/US 100	-
Net realized losses in the period[5]				
Three months ended September 30, 2011	$(56)	$(6)	-	$(4)
Nine months ended September 30, 2011	$(112)	$(14)	-	$(13)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

(1) All derivative financial instruments held for trading 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) As at December 31, 2011.
(4) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
(5) Realized and unrealized gains and losses on derivative financial instruments held for trading used to purchase and sell power and natural gas are included net 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.
(6) 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 $13 million and a notional amount of US$350 million at December 31, 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.
(7) 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 where it was probable that the anticipated transaction would not occur. 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 2012**	December 31 2011
Current		
Other current assets	**302**	361
Accounts payable	**(340)**	(485)
Long term		
Intangibles and other assets	**250**	202
Deferred amounts	**(211)**	(349)

Derivatives in Cash Flow Hedging Relationships

The components of OCI related to derivatives in cash flow hedging relationships are as follows:

Three months ended September 30 *(unaudited)* *(millions of dollars, pre-tax)*	Cash Flow Hedges Power **2012**	 2011	 Natural Gas **2012**	 2011	 Foreign Exchange **2012**	 2011	 Interest **2012**	 2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**96**	(25)	**(3)**	(14)	**(5)**	13	**-**	(1)
Reclassification of gains and (losses) on derivative instruments from AOCI to Net Income (effective portion)	**54**	26	**15**	27	**-**	-	**4**	11
Gains on derivative instruments recognized in earnings (ineffective portion)	**5**	1	**1**	1	**-**	-	**-**	-

Nine months ended September 30 *(unaudited)* *(millions of dollars, pre-tax)*	Cash Flow Hedges Power **2012**	 2011	 Natural Gas **2012**	 2011	 Foreign Exchange **2012**	 2011	 Interest **2012**	 2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**74**	(128)	**(17)**	(39)	**(5)**	6	**-**	(1)
Reclassification of gains on derivative instruments from AOCI to Net Income (effective portion)	**129**	58	**43**	80	**-**	-	**14**	33
Gains on derivative instruments recognized in earnings (ineffective portion)	**6**	2	**-**	-	**-**	-	**-**	-

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at September 30, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $41 million (2011 - $77 million), for which the Company had provided collateral of nil (2011 - $6 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2012, the Company would have been required to provide collateral of $41 million (2011 - $71 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the 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 that the Company has the ability to access at the measurement date.

In Level II, the fair value of interest rate and foreign exchange derivative assets and liabilities is determined using the income approach. The fair value of power and gas commodity assets and liabilities is determined using the market approach. Under both approaches, valuation is based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Such inputs include published exchange rates, interest rates, interest rate swap curves, yield curves, and broker quotes from external data service providers. Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in the nine months ended September 30, 2012 and 2011.

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

Long-dated commodity transactions in certain markets where liquidity is low are included in Level III of the fair value hierarchy, as the related commodity prices are not readily observable. Long-term electricity prices are estimated using a third-party modelling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Inputs into the model include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Long-term prices are reviewed by management and the Board on a periodic basis. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas may result in a lower fair value measurement of contracts included in Level III.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
(unaudited) *(millions of dollars, pre-tax)*	**Sept 30 2012**	Dec 31 2011	**Sept 30 2012**	Dec 31 2011	**Sept 30 2012**	Dec 31 2011	**Sept 30 2012**	Dec 31 2011
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**29**	36	**-**	-	**29**	36
Foreign exchange contracts	**-**	-	**160**	141	**-**	-	**160**	141
Power commodity contracts	**-**	-	**242**	201	**9**	-	**251**	201
Gas commodity contracts	**90**	124	**17**	55	**-**	-	**107**	179
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(16)**	(23)	**-**	-	**(16)**	(23)
Foreign exchange contracts	**-**	-	**(75)**	(102)	**-**	-	**(75)**	(102)
Power commodity contracts	**-**	-	**(318)**	(454)	**(5)**	(15)	**(323)**	(469)
Gas commodity contacts	**(114)**	(208)	**(18)**	(26)	**-**	-	**(132)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**32**	23	**-**	-	**-**	-	**32**	23
	8	(61)	**21**	(172)	**4**	(15)	**33**	(248)

The following table presents the net change in the Level III fair value category:

	Derivatives[1]			
	Three months ended September 30		Nine months ended September 30	
(unaudited) *(millions of dollars, pre-tax)*	**2012**	2011	**2012**	2011
Balance at beginning of period	**7**	(30)	**(15)**	(8)
New contracts	**-**	-	**-**	1
Settlements	**-**	1	**(1)**	1
Transfers out of Level III	**(12)**	2	**(10)**	2
Total gains included in Net Income[2]	**7**	-	**8**	-
Total gains/(losses) included in OCI	**2**	10	**22**	(13)
Balance at end of period	**4**	(17)	**4**	(17)

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) For the three and nine months ended September 31, 2012, the unrealized gains or losses included in Net Income attributed to derivatives that were still held at the reporting date was a loss of $1 million (2011 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $6 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at September 30, 2012.

9. Contingencies and Guarantees

TCPL and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

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 2012, TCPL currently expects spot prices to be less than the floor price for the year, therefore no amounts recorded in revenues in first nine months of 2012 are expected to be repaid.

Guarantees

TCPL and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TCPL and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TCPL's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $760 million at September 30, 2012. The fair value of these Bruce Power guarantees at September 30, 2012 is estimated to be $15 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, power purchase arrangement (PPA) payments and the payment of liabilities. TCPL's share of the potential maximum exposure under these assurances was estimated at September 30, 2012 to range from $160 million to $431 million. The fair value of these guarantees at September 30, 2012 is estimated to be $68 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

10. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

		2012		2011	
(unaudited) *(millions of Canadian dollars)*	Maturity Dates	**Outstanding September 30**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
Discount Notes	2012	**2,879**	**1.4%**	2,849	1.4%
Credit Facility		**(1,205)**	**3.0%**	(1,435)	3.0%
Credit Facility	2012	**(664)**	**3.8%**	(664)	3.8%
		1,010		750	