Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated April 28, 2011 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) for the three months ended March 31, 2011. In 2011, the Company will prepare its consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP) as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook, which is discussed further in the Changes in Accounting Policies section in this MD&A. This MD&A should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TCPL's 2010 Annual Report for the year ended December 31, 2010. Additional information relating to TCPL, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada PipeLines Limited. "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms used but not otherwise defined in this MD&A are identified in the Glossary of Terms contained in TCPL's 2010 Annual Report.

Forward-Looking Information

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TCPL security holders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of TCPL's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects, projects and financial performance of TCPL and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules (including anticipated construction and completion dates), operating and financial results, and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TCPL to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, including those material risks discussed in the Financial Instruments and Risk Management section in this MD&A, which could cause TCPL's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TCPL with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

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

EBITDA is an approximate measure of the Company's pre-tax operating cash flow and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Attributable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes Expense, respectively, adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments.

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

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

Reconciliation of Non-GAAP Measures

For the three months ended March 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines		Oil Pipelines		Energy		Corporate		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Comparable EBITDA	**796**	768	**99**	-	**354**	259	**(24)**	(26)	**1,225**	1,001
Depreciation and amortization	**(244)**	(253)	**(23)**	-	**(100)**	(90)	**(3)**	-	**(370)**	(343)
Comparable EBIT	**552**	515	**76**	-	**254**	169	**(27)**	(26)	**855**	658
Other Income Statement Items										
Comparable interest expense									**(238)**	(194)
Interest expense of joint ventures									**(16)**	(16)
Comparable interest income and other									**31**	24
Comparable income taxes									**(178)**	(114)
Net income attributable to non-controlling interests									**(30)**	(25)
Preferred share dividends									**(6)**	(6)
Comparable Earnings									**418**	327
Specific item (net of tax):										
Risk management activities(1)									**(10)**	(32)
Net Income Attributable to Common Shares									**408**	295

For the three months ended March 31 *(unaudited)(millions of dollars)*	**2011**	2010
Comparable Interest Expense	**(238)**	(194)
Specific item:		
Risk management activities(1)	**(1)**	-
Interest Expense	**(239)**	(194)
Comparable Interest Income and Other	**31**	24
Specific item:		
Risk management activities(1)	**2**	-
Interest Income and Other	**33**	24
Comparable Income Taxes	**(178)**	(114)
Specific item:		
Income taxes attributable to risk management activities(1)	**7**	17
Income Taxes Expense	**(171)**	**(97)**

(1)

For the three months ended March 31 *(unaudited) (millions of dollars)*	**2011**	2010
Risk Management Activities (Losses)/Gains:		
U.S. Power derivatives	**(13)**	(28)
Natural Gas Storage proprietary inventory and derivatives	**(5)**	(21)
Interest rate derivatives	**(1)**	-
Foreign exchange derivatives	**2**	-
Income taxes attributable to risk management activities	**7**	17
Risk Management Activities	**(10)**	(32)

Consolidated Results of Operations

TCPL's Net Income Attributable to Controlling Interests in first quarter 2011 was $414 million and Net Income Attributable to Common Shares was $408 million compared to $301 million and $295 million, respectively, in first quarter 2010.

Comparable Earnings in first quarter 2011 were $418 million compared to $327 million for the same period in 2010. Comparable Earnings in first quarter 2011 excluded net unrealized after tax losses of $10 million ($17 million pre-tax) (2010 – losses of $32 million after tax ($49 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $91 million in first quarter 2011 compared to the same period in 2010 and reflected the following:

- increased Natural Gas Pipelines Comparable EBIT primarily due to higher earnings from the Alberta System, reduced business development costs and incremental earnings from Bison which was placed in service in January 2011, partially offset by the negative impact of a weaker U.S. dollar on U.S. operations;

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

- increased Energy Comparable EBIT primarily due to higher prices for Western Power, increased volumes and lower costs at Bruce A, and incremental earnings from the start-up of Halton Hills in September 2010 and the second phase of Kibby Wind in October 2010, partially offset by lower realized prices and volumes at Bruce B, and decreased third-party storage and proprietary natural gas revenues for Natural Gas Storage;

- increased Comparable Interest Expense primarily due to decreased capitalized interest for Keystone, which commenced full operations in February 2011, and incremental interest expense on new debt issues in 2010, partially offset by realized losses in first quarter 2010 on derivatives used to manage the Company's exposure to fluctuating interest rates, Canadian dollar-denominated debt maturities and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;

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

- increased Comparable Income Taxes primarily due to higher pre-tax earnings; and

- increased Preferred Share Dividends due to new preferred share issues in 2010.

Further discussion of first quarter 2011 financial results is included in the Natural Gas Pipelines, Oil Pipelines, Energy and Other Income Statement Items sections in this MD&A.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is partially offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in U.S. foreign exchange rates. The average U.S. dollar exchange rate for the three months ended March 31, 2011 was 0.99 (2010 – 1.04).

Summary of Significant U.S. Dollar-Denominated Balances

(unaudited) *(millions of U.S. dollars, pre-tax)*	Three months ended March 31 **2011**	 2010
U.S. Natural Gas Pipelines Comparable EBIT[1]	**249**	226
U.S. Oil Pipelines Comparable EBIT[1]	**51**	-
U.S. Power Comparable EBIT[1]	**32**	39
Interest on U.S. dollar-denominated long-term debt	**(182)**	(159)
Capitalized interest on U.S capital expenditures	**47**	68
U.S. non-controlling interests and other	**(51)**	(45)
	146	129

(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 $552 million in first quarter 2011 compared to $515 million for the same period in 2010.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	2010
Canadian Natural Gas Pipelines		
Canadian Mainline	**265**	265
Alberta System	**185**	175
Foothills	**33**	33
Other (TQM, Ventures LP)	**12**	13
Canadian Natural Gas Pipelines Comparable EBITDA[1]	**495**	486
Depreciation and amortization	**(180)**	(183)
Canadian Natural Gas Pipelines Comparable EBIT[1]	**315**	303
U.S. Natural Gas Pipelines (in U.S. dollars)		
ANR	**111**	115
GTN	**45**	43
Great Lakes[2]	**30**	32
PipeLines LP[3][4]	**27**	25
Iroquois	**19**	18
Bison[5]	**13**	-
Portland[4][6]	**10**	10
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**10**	10
General, administrative and support costs[7]	**(2)**	(6)
Non-controlling interests[4]	**50**	46
U.S. Natural Gas Pipelines Comparable EBITDA[1]	**313**	293
Depreciation and amortization	**(64)**	(67)
U.S. Natural Gas Pipelines Comparable EBIT[1]	**249**	226
Foreign exchange	**(4)**	9
U.S. Natural Gas Pipelines Comparable EBIT[1] (in Canadian dollars)	**245**	235
Natural Gas Pipelines Business Development Comparable EBITDA[1]	**(8)**	(23)
Natural Gas Pipelines Comparable EBIT[1]	**552**	515
Summary:		
Natural Gas Pipelines Comparable EBITDA[1]	**796**	768
Depreciation and amortization	**(244)**	(253)
Natural Gas Pipelines Comparable EBIT[1]	**552**	515

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Represents the Company's 53.6 per cent direct ownership interest.
(3) Represents the Company's 38.2 per cent ownership interest.
(4) Non-Controlling Interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TCPL.
(5) Includes Bison's operations since January 2011.
(6) Represents the Company's 61.7 per cent ownership interest.
(7) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	 2010
Canadian Mainline	**62**	66
Alberta System	**48**	38
Foothills	**6**	6

Canadian Natural Gas Pipelines

Canadian Mainline's net income in first quarter 2011 was $62 million, a decrease of $4 million, from the same period in 2010. Net income in first quarter 2011 reflected a lower average investment base as well as a lower rate of return on common equity (ROE), as determined by the National Energy Board (NEB), of 8.08 per cent in 2011 compared to 8.52 per cent in 2010. The lower ROE and average investment base was partially offset by higher OM&A cost savings in 2011.

Canadian Mainline's Comparable EBITDA in first quarter 2011 of $265 million was consistent with first quarter 2010. A decrease in revenues as a result of a lower overall return, associated with a reduced ROE and financial charges, on a reduced average investment base, was offset by a recovery of higher flow-through costs. The flow-through costs do not impact net income and increased due to higher income taxes, partially offset by the lower financial charges.

The Alberta System's net income was $48 million in first quarter 2011 compared to $38 million in the same quarter of 2010. The increase reflected an ROE of 9.70 per cent on 40 per cent deemed common equity approved by the NEB in September 2010 as part of the Company's 2010 - 2012 Revenue Requirement Settlement application. Net income in first quarter 2010 reflected an ROE of 8.75 per cent on 35 per cent deemed common equity.

The Alberta System's Comparable EBITDA was $185 million in first quarter 2011 compared to $175 million for the same period in 2010. The increase was primarily due to the increased ROE included in the 2010 - 2012 Revenue Requirement Settlement.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA in first quarter 2011 was US$111 million compared to US$115 million for the same period in 2010. The decrease was primarily due to higher OM&A costs.

The Bison pipeline was placed in service in January 2011 and contributed US$13 million of EBITDA in first quarter 2011.

Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines in first quarter 2011 was US$189 million compared to US$178 million for the same period in 2010. The increase was primarily due to higher earnings from Northern Border and GTN, and lower general, administrative and support costs.

Depreciation

Natural Gas Pipelines' depreciation decreased $9 million in first quarter 2011 compared to the same period in 2010 primarily due to Great Lakes' lower depreciation rate per its rate settlement, partially offset by incremental depreciation for Bison.

Business Development

Natural Gas Pipelines' Business Development Comparable EBITDA loss decreased $15 million in first quarter 2011 compared to the same period in 2010 primarily due to an increased level of reimbursement by the State of Alaska for costs related to the Alaska Pipeline Project. The State of Alaska reimbursed up to 50 per cent of the eligible costs incurred for the Alaska Pipeline Project prior to the close of the first binding open season on July 30, 2010. Commencing July 31, 2010, the State began reimbursing up to 90 per cent of the eligible costs. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TCPL's joint venture partner in developing the Alaska Pipeline Project. The decrease in business development costs was partially offset by a levy charged by the NEB in March 2011 to recover the Aboriginal Pipeline Group's (APG) proportionate share of costs relating to the Mackenzie Gas Project (MGP) hearings.

Operating Statistics

Three months ended March 31 *(unaudited)*	Canadian Mainline[1] 2011	2010	Alberta System[2] 2011	2010	Foothills 2011	2010	ANR[3] 2011	2010	GTN[3] 2011	2010
Average investment base (millions of dollars)	**6,404**	6,629	**4,966**	4,956	**624**	677	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**597**	560	**1,000**	938	**329**	328	**480**	447	**176**	207
Average per day	**6.6**	6.2	**11.1**	10.4	**3.7**	3.6	**5.3**	5.0	**2.0**	2.3

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the three months ended March 31, 2011 were 376 billion cubic feet (Bcf) (2010 – 385 Bcf); average per day was 4.2 Bcf (2010 – 4.3 Bcf).

(2) Field receipt volumes for the Alberta System for the three months ended March 31, 2011 were 843 Bcf (2010 – 855 Bcf); average per day was 9.4 Bcf (2010 – 9.5 Bcf).

(3) ANR's and GTN's results are not impacted by average investment base as these systems operate under fixed-rate models approved by the U.S. Federal Energy Regulatory Commission.

Oil Pipelines

In first quarter 2011, the Company recorded $76 million of Comparable EBIT related to the Keystone oil pipeline. In late January 2011, work was completed to allow the Wood River/Patoka section of the system to operate at its design pressure following the NEB's decision to remove the maximum operating pressure restriction in December 2010. The Company commenced recording EBITDA for the Wood River/Patoka section of Keystone at the beginning of February 2011. In February 2011, the Cushing Extension was placed in service and TCPL also began recording EBITDA related to this section of Keystone. Cash flows related to Keystone, other than general, administrative and support costs, were capitalized until the Company began recording EBITDA.

Oil Pipelines Results

For the period February 1 to March 31 *(unaudited)(millions of dollars)*	**2011**
Canadian Oil Pipelines Comparable EBITDA[1]	**35**
Depreciation and amortization	**(9)**
Canadian Oil Pipelines Comparable EBIT[1]	**26**
U.S. Oil Pipelines Comparable EBITDA[1] (in U.S. dollars)	**65**
Depreciation and amortization	**(14)**
U.S. Oil Pipelines Comparable EBIT[1]	**51**
Foreign exchange	**(1)**
U.S. Oil Pipelines Comparable EBIT[1] (in Canadian dollars)	**50**
Oil Pipelines Comparable EBIT[1]	**76**
Summary:	
Oil Pipelines Comparable EBITDA[1]	**99**
Depreciation and amortization	**(23)**
Oil Pipelines Comparable EBIT[1]	**76**

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

Operating Statistics

For the period February 1 to March 31 *(unaudited)*	**2011**
Delivery volumes (thousands of barrels)[1]:	
Total	**22,466**
Average per day	**381**

(1) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $254 million in first quarter 2011 compared to $169 million for the same period in 2010.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	 2010
Canadian Power		
Western Power	**120**	42
Eastern Power[1]	**80**	52
Bruce Power	**77**	63
General, administrative and support costs	**(8)**	(10)
Canadian Power Comparable EBITDA[2]	**269**	147
Depreciation and amortization	**(67)**	(60)
Canadian Power Comparable EBIT[2]	**202**	87
U.S. Power (in U.S. dollars)		
Northeast Power[3]	**71**	73
General, administrative and support costs	**(9)**	(9)
U.S. Power Comparable EBITDA[2]	**62**	64
Depreciation and amortization	**(30)**	(25)
U.S. Power Comparable EBIT[2]	**32**	39
Foreign exchange	**-**	1
U.S. Power Comparable EBIT[2] (in Canadian dollars)	**32**	40
Natural Gas Storage		
Alberta Storage	**31**	53
General, administrative and support costs	**(2)**	(2)
Natural Gas Storage Comparable EBITDA[2]	**29**	51
Depreciation and amortization	**(4)**	(4)
Natural Gas Storage Comparable EBIT[2]	**25**	47
Energy Business Development Comparable EBITDA[2]	**(5)**	(5)
Energy Comparable EBIT[2]	**254**	169
Summary:		
Energy Comparable EBITDA[2]	**354**	259
Depreciation and amortization	**(100)**	(90)
Energy Comparable EBIT[2]	**254**	169

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

Canadian Power

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

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	2010
Revenues		
Western power	**279**	164
Eastern power	**118**	67
Other[(3)]	**23**	22
	420	253
Commodity Purchases Resold		
Western power	**(143)**	(106)
Other[(4)]	**(5)**	(5)
	(148)	(111)
Plant operating costs and other	**(72)**	(48)
General, administrative and support costs	**(8)**	(10)
Comparable EBITDA[(1)]	**192**	84
Depreciation and amortization	**(39)**	(37)
Comparable EBIT[(1)]	**153**	47

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

Western and Eastern Canadian Power Operating Statistics

(unaudited)	Three months ended March 31 **2011**	2010
Sales Volumes (GWh)		
Supply		
Generation		
Western Power	**681**	585
Eastern Power[(1)]	**1,078**	429
Purchased		
Sundance A & B and Sheerness PPAs[(2)]	**2,105**	2,655
Other purchases	**202**	149
	4,066	3,818
Sales		
Contracted		
Western Power	**2,269**	2,269
Eastern Power[(1)]	**1,078**	445
Spot		
Western Power	**719**	1,104
	4,066	3,818
Plant Availability[(3)]		
Western Power[(4)]	**98%**	95%
Eastern Power[(1)(5)]	**99%**	96%

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

Western Power's Comparable EBITDA of $120 million and Power Revenues of $279 million in first quarter 2011 increased $78 million and $115 million, respectively, compared to the same period in 2010, primarily due to higher overall realized power prices. Average spot market power prices in Alberta increased 104 per cent to $83 per megawatt hour (MWh) in first quarter 2011 compared to $41 per MWh in first quarter 2010 due to unseasonably cold weather combined with unplanned plant outages, which caused an increase in demand and a reduction in market supply. Western Power's Comparable EBITDA in first quarter 2011 included $39 million of earnings from the Sundance A power purchase arrangement (PPA), the revenues and costs of which have been recorded as though Units 1 and 2 were on normal plant outages. Refer to the Recent Developments section in this MD&A for further discussion regarding the Sundance A outage.

Western Power's Commodity Purchases Resold increased $37 million in first quarter 2011 compared to the same period in 2010 primarily due to higher volumes at Sheerness and increased retail contracts.

Eastern Power's Comparable EBITDA of $80 million and Power Revenues of $118 million in first quarter 2011 increased $28 million and $51 million, respectively, compared to the same period in 2010. The increases were primarily due to incremental earnings from Halton Hills, which went into service in September 2010.

Plant Operating Costs and Other of $72 million in first quarter 2011, which includes fuel gas consumed in power generation, increased $24 million compared to the same period in 2010 primarily due to incremental fuel consumed at Halton Hills.

Western Power manages the sale of its supply volumes on a portfolio basis. A portion of its supply is sold into the spot market to assure supply in case of an unexpected plant outage. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where Western Power would otherwise have to purchase electricity in the open market to fulfill its contractual sales obligations. Approximately 76 per cent of Western Power sales volumes were sold under contract in first quarter 2011, compared to 67 per cent in first quarter 2010. To reduce its exposure to spot market prices on uncontracted volumes, as at March 31, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 6,300 gigawatt hours (GWh) for the remainder of 2011 and 6,800 GWh for 2012.

Eastern Power is focused on selling power under long-term contracts. In first quarter 2011 and 2010, 100 per cent of Eastern Power's sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for the remainder of 2011 and 2012.

Bruce Power Results[1]

(TCPL's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended March 31 **2011**	 2010
Revenues[2]	**213**	225
Operating Expenses	**(136)**	(162)
Comparable EBITDA[1]	**77**	63
Bruce A Comparable EBITDA[1]	**34**	13
Bruce B Comparable EBITDA[1]	**43**	50
Comparable EBITDA[1]	**77**	63
Depreciation and amortization	**(28)**	(23)
Comparable EBIT[1]	**49**	40
Bruce Power – Other Information		
Plant availability		
Bruce A	**100%**	65%
Bruce B	**91%**	98%
Combined Bruce Power	**94%**	87%
Planned outage days		
Bruce A	**-**	35
Bruce B	**21**	-
Unplanned outage days		
Bruce A	**4**	26
Bruce B	**8**	6
Sales volumes (GWh)		
Bruce A	**1,500**	989
Bruce B	**2,032**	2,155
	3,532	3,144
Results per MWh		
Bruce A power revenues	**$65**	$64
Bruce B power revenues[3]	**$53**	$58
Combined Bruce Power revenues	**$57**	$60
Percentage of Bruce B output sold to spot market[4]	**90%**	78%

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Revenues include Bruce A's fuel cost recoveries of $8 million for the three months ended March 31, 2011 (2010 – $5 million).
(3) Includes revenues received under the floor price mechanism, from contract settlements and deemed generation, and the associated volumes.
(4) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TCPL's proportionate share of Bruce A's Comparable EBITDA increased $21 million to $34 million in first quarter 2011 as a result of higher volumes and lower operating expenses due to decreased outage days. Bruce A's plant availability in first quarter 2011 was 100 per cent with four outage days compared to an availability of 65 per cent and 61 outage days for the same period in 2010. Results in first quarter 2010 also included the positive impact of a payment made from Bruce B to Bruce A regarding 2009 amendments to a long-term agreement with the Ontario Power Authority (OPA). The net positive impact reflected TCPL's higher percentage ownership interest in Bruce A.

TCPL's proportionate share of Bruce B's Comparable EBITDA decreased $7 million to $43 million in first quarter 2011 from $50 million in first quarter 2010 due to lower realized prices resulting from the expiry of fixed-price contracts at higher prices, and lower volumes and higher operating expenses due to increased outage days, partially offset by the payment made in first quarter 2010 to Bruce A regarding the 2009 amendments to a long-term agreement with the OPA. Bruce B's plant availability in first quarter 2011 was 91 per cent with 29 outage days compared to an availability of 98 per cent and six outage days in the same period in 2010.

Under a contract with the OPA, all output from Bruce A in first quarter 2011 was sold at a fixed price of $64.71 per MWh (before recovery of fuel costs from the OPA) compared to $64.45 per MWh in first quarter 2010. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $48.96 per MWh in first quarter 2011 compared to $48.76 per MWh in first quarter 2010. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1. Effective April 1, 2011, the fixed price for output from Bruce A increased to $66.33 per MWh and the Bruce B floor price increased to $50.18 per MWh.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. With respect to 2011, TCPL currently expects spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenues in first quarter 2011 are expected to be repaid.

Bruce B enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price decreased $5 per MWh to $53 per MWh in first quarter 2011 compared to the same period in 2010 and reflected revenues recognized from both the floor price mechanism and contract sales. The decrease was a result of the majority of higher-priced contracts entered into in previous years expiring by the end of December 2010. As the remaining contracts expire, a further reduction in realized prices at Bruce B in future periods is expected. At March 31, 2011, Bruce B had sold forward net volumes of approximately 500 GWh and 670 GWh, representing TCPL's proportionate share, for the remainder of 2011 and 2012, respectively.

The overall plant availability percentage in 2011 is expected to be in the mid-80s for the two operating Bruce A units and in the high 80s for the four Bruce B units. A planned maintenance outage of approximately seven weeks commenced on April 15, 2011 on Bruce B Unit 7. Bruce A expects an outage of approximately one week on Unit 3 in June 2011. For further information on Bruce Power's planned maintenance outages, refer to the MD&A in TCPL's 2010 Annual Report.

As at March 31, 2011, Bruce A had incurred approximately $4.2 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.3 billion for the refurbishment of Units 3 and 4.

U.S. Power

U.S. Power Comparable EBIT[1][2]

(unaudited) *(millions of U.S. dollars)*	Three months ended March 31 **2011**	 2010
Revenues		
Power[3]	**255**	232
Capacity	**39**	40
Other[4]	**30**	25
	324	297
Commodity purchases resold	**(131)**	(136)
Plant operating costs and other[4]	**(122)**	(88)
General, administrative and support costs	**(9)**	(9)
Comparable EBITDA[1]	**62**	64
Depreciation and amortization	**(30)**	(25)
Comparable EBIT[1]	**32**	39

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

U.S. Power Operating Statistics[1]

(unaudited)	Three months ended March 31 **2011**	 2010
Sales Volumes (GWh)		
Supply		
Generation	**1,291**	891
Purchased	**1,939**	2,486
	3,230	3,377
Plant Availability[2][3]	**82%**	86%

(1) Includes phase two of Kibby Wind effective October 2010.
(2) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(3) Plant availability decreased in the three months ended March 31, 2011 due to the impact of a planned outage at Ravenswood.

U.S. Power's Power Revenues in first quarter 2011 of US$255 million increased from US$232 million in the same period in 2010 as a result of higher realized power prices and incremental revenues from the second phase of Kibby Wind which was placed in service in October 2010, partially offset by lower volumes of power sold.

Commodity Purchases Resold of US$131 million in first quarter 2011 decreased from US$136 million in the same period in 2010 primarily due to a decrease in the quantity of power purchased for resale under power sales commitments to wholesale, commercial and industrial customers in New England in first quarter 2011, partially offset by higher power prices per MWh purchased.

Plant Operating Costs and Other, which includes fuel gas consumed in generation of US$122 million in first quarter 2011, increased US$34 million over the same period in 2010 primarily due to higher fuel costs as a result of increased generation in first quarter 2011 and reduced lease costs in first quarter 2010.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM Interconnection power markets. Exposure to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts. As at March 31, 2011, approximately 4,300 GWh or 60 per cent of U.S. Power's planned generation is contracted for the remainder of 2011. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets, and power sales fluctuate based on customer usage. The seasonal nature of the U.S. Power business generally results in higher generation volumes in the summer months.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA in first quarter 2011 was $29 million compared to $51 million for the same period in 2010. The decrease in Comparable EBITDA in first quarter 2011 was primarily due to decreased third-party storage and proprietary natural gas revenues as a result of lower realized natural gas price spreads.

Other Income Statement Items

Comparable Interest Expense

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	2010
Interest on long-term debt[1]		
Canadian dollar-denominated	**122**	131
U.S. dollar-denominated	**182**	159
Foreign exchange	**(3)**	6
	301	296
Other interest and amortization	**35**	32
Capitalized interest	**(97)**	(134)
Comparable Interest Expense[2]	**239**	194

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

Comparable Interest Expense in first quarter 2011 increased $45 million to $239 million from $194 million in first quarter 2010. The increase reflected decreased capitalized interest for Keystone, which commenced full operations in February 2011, and incremental interest expense on debt issues of US$1.25 billion in June 2010 and US$1.0 billion in September 2010. These increases were partially offset by Canadian dollar-denominated debt maturities in 2010 and 2011, and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest. Comparable Interest Expense in first quarter 2010 included losses on derivatives used to manage TCPL's exposure to fluctuating interest rates.

Comparable Interest Income and Other in first quarter 2011 increased $7 million to $31 million from $24 million in first quarter 2010. The increase reflected higher realized gains on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable Income Taxes were $178 million in first quarter 2011 compared to $114 million for the same period in 2010. The increase was primarily due to higher pre-tax earnings in 2011 compared to 2010.

Liquidity and Capital Resources

TCPL's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TCPL's liquidity is underpinned by predictable cash flow from operations, cash balances on hand and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$800 million, maturing in November 2011, December 2012 and December 2012, respectively. These facilities also support the Company's commercial paper programs. In addition, at March 31, 2011, TCPL's proportionate share of unutilized capacity on committed bank facilities at TCPL-operated affiliates was $113 million with maturity dates in 2011 and 2012. As at March 31, 2011, TCPL had remaining capacity of $2.0 billion and US$1.75 billion under its Canadian debt and U.S. debt shelf prospectuses, respectively. TCPL's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

At March 31, 2011, the Company held Cash and Cash Equivalents of $0.5 billion compared to $0.8 billion at December 31, 2010. The decrease in Cash and Cash Equivalents was primarily due to expenditures for the Company's capital program, debt repayments and dividend payments, partially offset by increased cash generated from operations.

Operating Activities

Funds Generated from Operations(1)

(unaudited)	Three months ended March 31	
(millions of dollars)	**2011**	2010
Cash Flows		
Funds generated from operations(1)	**895**	712
Decrease in operating working capital	**110**	116
Net cash provided by operations	**1,005**	828

(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 $177 million for the three months ended March 31, 2011 compared to the same period in 2010, reflecting increased Funds Generated from Operations and changes in operating working capital. Funds Generated from Operations for the first quarter 2011 were $895 million compared to $712 million for the same period in 2010. The increase was primarily due to an increase in cash generated through earnings.

As at March 31, 2011, TCPL's current liabilities were $5.1 billion and current assets were $4.1 billion resulting in a working capital deficiency of $1.0 billion. Excluding $2.2 billion of Notes Payable under the Company's commercial paper programs and draws on its line-of-credit facilities, TCPL's working capital was $1.2 billion.

Investing Activities

TCPL remains committed to executing its remaining $11 billion capital expenditure program. For the three months ended March 31, 2011, capital expenditures totalled $0.8 billion (2010 – $1.3 billion) primarily related to refurbishment and restart of Bruce A Units 1 and 2, Keystone, expansion of the Alberta System, and construction of the Guadalajara natural gas pipeline.

Financing Activities

In January 2011, TCPL retired $300 million of 4.3 per cent debentures.

The Company is well positioned to fund its existing capital program through its internally-generated cash flow and its continued access to capital markets. TCPL will also continue to examine opportunities for portfolio management, including an ongoing role for PipeLines LP, in financing its capital program.

Dividends

On April 28, 2011, TCPL's Board of Directors declared a quarterly dividend for the quarter ending June 30, 2011 in the aggregate amount equal to the quarterly dividend paid on TransCanada Corporation's (TransCanada) issued and outstanding common shares at the close of business on June 30, 2011. The dividend is payable on July 29, 2011. The Board also declared a dividend of $0.70 per share for the period ending July 30, 2011 on TCPL's Series U and Y preferred shares. The dividend is payable on August 2, 2011 to shareholders of record at the close of business on June 30, 2011.

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

Contractual Obligations

During first quarter 2011, TCPL had a net reduction to its purchase obligations primarily due to the settlement of its commitments in the normal course of business. There have been no other material changes to TCPL's contractual obligations from December 31, 2010 to March 31, 2011, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TCPL's 2010 Annual Report.

Significant Accounting Policies and Critical Accounting Estimates

To prepare financial statements that conform with GAAP, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions.

TCPL's significant accounting policies and critical accounting estimates have remained unchanged since December 31, 2010. For further information on the Company's accounting policies and estimates refer to the MD&A in TCPL's 2010 Annual Report.

Changes in Accounting Policies

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

Changes in Accounting Policies for 2011

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests
Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a

significant impact on the way the Company accounts for future business combinations. Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 “Consolidated Financial Statements” and 1602 “Non-Controlling Interests”. Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Shareholders’ Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary’s results and presents the allocation of income between the controlling and non-controlling interests. Changes resulting from the adoption of Section 1582 were applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

U.S. GAAP/International Financial Reporting Standards
The CICA’s Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), effective January 1, 2011.

In accordance with GAAP, TCPL follows specific accounting policies unique to a rate-regulated business. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls.

In July 2009, the IASB issued an Exposure Draft “Rate-Regulated Activities”, which proposed a form of RRA under IFRS. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis and removed the RRA project from its current agenda. TCPL does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

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

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

U.S. GAAP Conversion Project
Effective January 1, 2012, the Company will begin reporting under U.S. GAAP. TCPL’s IFRS conversion team has been redeployed to support the conversion to U.S. GAAP. The conversion team is led by a multi-disciplinary Steering Committee that provides directional leadership for the adoption of U.S. GAAP. Management also updates TCPL’s Audit Committee on the progress of the U.S. GAAP project at each Audit Committee meeting.

U.S. GAAP training is being provided to TCPL staff and directors who are impacted by the conversion. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company’s primary accounting standard since TCPL prepares and files a “Reconciliation to United States GAAP”.

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

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

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

Income Tax
Canadian GAAP requires that the Company record current income tax benefits resulting from substantively enacted Canadian federal income tax legislation. Under U.S. GAAP, the legislation must be fully enacted for income tax adjustments to be recorded.

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

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

Financial Instruments and Risk Management

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

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets, and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At March 31, 2011, there were no significant amounts past due or impaired.

At March 31, 2011, the Company had a credit risk concentration of $297 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions.

Natural Gas Storage Commodity Price Risk

At March 31, 2011, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $49 million (December 31, 2010 - $49 million). The change in the fair value adjustment of proprietary natural gas inventory in storage in the three months ended March 31, 2011 resulted in net pre-tax unrealized gains of $2 million (2010 - losses of $24 million), which was recorded as an increase in Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three months ended March 31, 2011 resulted in net pre-tax unrealized losses of $7 million (2010 – gains of $3 million), which was included in Revenues.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TCPL's consolidated VaR was $14 million at March 31, 2011 (December 31, 2010 – $12 million). The increase from December 31, 2010 was primarily due to increased Alberta power forward prices as well as increased price volatility in the Alberta power market.

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 March 31, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.5 billion (US$9.8 billion) and a fair value of $10.8 billion (US$11.1 billion). At March 31, 2011, $251 million (December 31, 2010 - $181 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**March 31, 2011** **Fair Value**[(1)]	**March 31, 2011** **Notional or Principal Amount**	December 31, 2010 Fair Value[(1)]	December 31, 2010 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2017)	**246**	**US 3,150**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2011)	**5**	**US 550**	2	US 100
	251	**US 3,700**	181	US 2,900

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**March 31, 2011** Carrying Amount	**March 31, 2011** Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**544**	**544**	752	752
Accounts receivable and other[2][3]	**1,585**	**1,619**	1,564	1,604
Due from TransCanada Corporation	**1,279**	**1,279**	1,363	1,363
Available-for-sale assets[2]	**25**	**25**	20	20
	3,433	**3,467**	3,699	3,739
Financial Liabilities[1][3]				
Notes payable	**2,192**	**2,192**	2,092	2,092
Accounts payable and deferred amounts[4]	**1,125**	**1,125**	1,444	1,444
Due to TransCanada Corporation	**2,703**	**2,703**	2,703	2,703
Accrued interest	**366**	**366**	361	361
Long-term debt	**17,327**	**20,416**	17,922	21,523
Junior subordinated notes	**962**	**969**	985	992
Long-term debt of joint ventures	**849**	**944**	866	971
	25,524	**28,715**	26,373	30,086

(1) Consolidated Net Income in first quarter 2011 included losses of $9 million (2010 – losses of $7 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At March 31, 2011, the Consolidated Balance Sheet included financial assets of $1,266 million (December 31, 2010 – $1,280 million) in Accounts Receivable, $38 million (December 31, 2010 – $40 million) in Other Current Assets and $306 million (December 31, 2010 - $264 million) in Intangibles and Other Assets.

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

(4) At March 31, 2011, the Consolidated Balance Sheet included financial liabilities of $1,093 million (December 31, 2010 – $1,507 million) in Accounts Payable and $32 million (December 31, 2010 - $30 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

March 31, 2011 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$175**	**$123**	**$10**	**$17**
Liabilities	**$(132)**	**$(154)**	**$(16)**	**$(18)**
Notional Values				
Volumes[3]				
Purchases	**21,828**	**169**	**-**	**-**
Sales	**24,462**	**132**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**836**
U.S. dollars	**-**	**-**	**US 1,839**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2011[4]	**$(1)**	**$(16)**	**$2**	**$(1)**
Net realized gains/(losses) in the three months ended March 31, 2011[4]	**$3**	**$(26)**	**$21**	**$2**
Maturity dates	**2011-2015**	**2011-2015**	**2011-2012**	**2011-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$75**	**$6**	**$-**	**$9**
Liabilities	**$(177)**	**$(19)**	**$(56)**	**$(19)**
Notional Values				
Volumes[3]				
Purchases	**18,273**	**16**	**-**	**-**
Sales	**7,906**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 120**	**US 1,000**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized losses in the three months ended March 31, 2011[4]	**$(38)**	**$(3)**	**$-**	**$(5)**
Maturity dates	**2011-2015**	**2011-2013**	**2011- 2014**	**2011-2015**

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

(2) Fair values equal carrying values.

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

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments 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 $9 million and a notional amount of US$350 million. Net realized gains on fair value hedges for

the three months ended March 31, 2011 were $2 million and were included in Interest Expense. In first quarter 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three months ended March 31, 2011, Net Income included losses of $3 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. For the three months ended March 31, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values(1)(2)				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values(2)				
Volumes(3)				
Purchases	15,610	158	-	-
Sales	18,114	96	-	-
Canadian dollars	-	-	-	736
U.S. dollars	-	-	US 1,479	US 250
Cross-currency	-	-	47/ US 37	-
Net unrealized (losses)/gains in the three months ended March 31, 2010(4)	$(16)	$2	-	$(4)
Net realized gains/(losses) in the three months ended March 31, 2010(4)	$22	$(12)	$8	$(4)
Maturity dates(2)	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(1)(2)				
Assets	$112	$5	$-	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values(2)				
Volumes(3)				
Purchases	16,071	17	-	-
Sales	10,498	-	-	-
U.S. dollars	-	-	US 120	US 1,125
Cross-currency	-	-	136/US 100	-
Net realized losses in the three months ended March 31, 2010(4)	($7)	$(3)	-	$(10)
Maturity dates(2)	2011-2015	2011-2013	2011-2014	2011-2015

(1) Fair values equal carrying values.
(2) As at December 31, 2010.
(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments 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 $8 million and a notional amount of US$250 million at December 31, 2010. Net realized gains on fair value hedges for the three months ended March 31, 2010 were $1 million and were included in Interest Expense. In first quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
(6) For the three months ended March 31, 2010, Net Income included losses of $8 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. For the

three months ended March 31, 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**March 31, 2011**	December 31, 2010
Current		
Other current assets	**243**	273
Accounts payable	**(326)**	(337)
Long-term		
Intangibles and other assets	**423**	374
Deferred amounts	**(265)**	(282)

Other Risks

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

Controls and Procedures

As of March 31, 2011, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of TCPL's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TCPL's disclosure controls and procedures were effective at a reasonable assurance level as at March 31, 2011.

During the recent fiscal quarter, there have been no changes in TCPL's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, TCPL's internal control over financial reporting.

Outlook

Since the disclosure in TCPL's 2010 Annual Report, the Company's earnings outlook for 2011 has improved due to higher overall realized power prices in Western Power in first quarter 2011. With the expectation of more normalized weather and additional generation capacity coming into the Alberta market, TCPL does not expect these prices to remain at the higher first quarter levels for the remainder of 2011. For further information on outlook, refer to the MD&A in TCPL's 2010 Annual Report.

Recent Developments

Natural Gas Pipelines

Canadian Mainline

In February 2011, the NEB approved TCPL's application for revised interim 2011 Canadian Mainline tolls, effective March 1, 2011. The revised interim tolls are consistent with the existing 2007-2011 settlement with two adjustments that resulted in a lower revenue requirement and therefore lower interim tolls. TCPL is preparing an application to the NEB for approval of final rates for 2011, which it expects to file on April 29, 2011. The Company has continued discussions with shippers and other stakeholders to develop a tolling arrangement for the next several years to enhance the competitiveness of the Canadian Mainline and the Western Canadian Sedimentary Basin. Unfortunately, discussions have not resulted in such an arrangement and it appears that TCPL will be filing a comprehensive application with the NEB later in 2011 to address tolls for 2012 and beyond.

In first quarter 2011, throughput volumes and revenues were higher than projected in the 2011 interim tolls application due to colder than anticipated weather. The final revenue variance for 2011 will depend on actual throughput volumes in 2011 and an NEB decision for final 2011 costs and tolls.

TCPL held a successful open season that closed in January 2011 and resulted in executed precedent agreements for the Canadian Mainline to transport 230,000 gigajoules per day (GJ/d) of natural gas from Marcellus shale gas reserves to eastern markets. The Company held another open season to respond to market interest in transporting additional Marcellus shale volumes on the Canadian Mainline. That open season closed April 15, 2011 and is expected to result in the transportation of an additional 150,000 GJ/d to markets east of the Parkway delivery point near Hamilton, Ontario, beginning November 1, 2013. Executed precedent agreements from these open seasons are expected to be used to support a facilities application that the Company plans to file with the NEB in third quarter 2011.

Alberta System

The Alberta System continues to operate under 2011 interim tolls approved by the NEB in 2010. TCPL anticipates filing for final 2011 tolls in second quarter 2011 that would reflect the provisions of the Alberta System 2010 – 2012 Revenue Requirement Settlement and commercial integration of the ATCO Pipelines system. The Company expects the revised tolls to be effective in third quarter 2011.

The Horn River natural gas pipeline project was approved by the NEB in January 2011 and commenced construction in March 2011.

The Company has executed an agreement securing contractual support for a new project to connect 100 million cubic feet per day (mmcf/d) of new natural gas supply in northeastern B.C. by 2014 with volumes expected to increase to 300 mmcf/d by 2020. This project is expected to extend the Horn River pipeline by approximately 100 kilometres (km) (62 miles) and to have an estimated capital cost of $265 million.

In addition to the Horn River project, TCPL continues to advance further pipeline development in B.C. and Alberta to transport new natural gas supplies. The Company has filed several applications with the NEB requesting approval of further expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest portion of the Western Canadian Sedimentary Basin. The total aggregate capital cost of these expansion projects is estimated to be $475 million.

PipeLines LP

On April 26, 2011, the Company announced it entered into agreements to sell a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to PipeLines LP for an aggregate purchase price of US$605 million, which includes US$81 million of long-term debt or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively. The sale is expected to close in May 2011 and is subject to certain closing conditions.

At the end of April 2011, PipeLines LP announced an underwritten public offering of 6,300,000 common units at US$47.58 per unit. Gross proceeds of approximately US$300 million from this offering will be used to partially fund the acquisition with the balance funded by a draw on PipeLines LP's committed and available US$400 million bridge loan facility and a draw on PipeLines LP's US$250 million committed and available senior revolving credit facility. The underwriters were also granted a 30-day option to purchase an additional 945,000 common units at the same price. The offering is expected to close on May 3, 2011.

As part of this offering, TCPL will make a capital contribution of US$6 million to maintain its two per cent general partnership interest in PipeLines LP. Assuming the underwriters exercise their option to purchase additional units, TCPL's ownership in PipeLines LP is expected to be approximately 33.3 per cent.

Mackenzie Gas Project

In March 2011, the MGP received a Certificate of Public Convenience and Necessity from the NEB, marking the end of the federal regulatory process. The MGP proponents continue to seek the Canadian government's support of an acceptable fiscal framework which would allow the project to progress. TCPL remains committed to advancing the project.

Guadalajara

Construction of the 305 km (190 miles) Guadalajara natural gas pipeline in Mexico was approximately 90 per cent complete as of mid-April 2011. In addition, TCPL and the Comisión Federal de Electricidad recently executed a contract to add a compressor station to the pipeline. The total capital cost of the project, including the compressor station, is expected to be approximately US$420 million. The pipeline is expected to commence commercial operations in late second quarter 2011 and the compressor station is anticipated to be in service in early 2013.

Alaska Pipeline Project

The Alaska Pipeline Project team continues to work with shippers to resolve conditional bids received as part of the project's open season and is working toward the U.S. Federal Energy Regulatory Commission (FERC) application deadline of October 2012.

Oil Pipelines

Keystone

In late January 2011, work was completed to allow the Wood River/Patoka section of the system to operate at its design pressure following the NEB's decision to remove the maximum operating pressure restriction in December 2010. In February 2011, the Cushing Extension commenced commercial operations, extending the pipeline system to Cushing, Oklahoma and increasing nominal capacity to 591,000 Bbl/d.

TCPL's Keystone U.S. Gulf Coast Expansion is now entering the final stages of regulatory review. On April 15, 2011, the U.S. Department of State (DOS), the lead agency for U.S. federal regulatory approvals, issued a Supplemental Draft Environmental Impact Statement (SDEIS) in response to comments received on a Draft Environmental Impact Statement (DEIS) issued in April 2010 and to address new and additional information received. The SDEIS provides additional information on key environmental issues, but does not change the conclusion reached in the DEIS that the project would enhance U.S. energy security, benefit the U.S. economy and have limited environmental impact. The DOS has invited interested parties to comment on the SDEIS during a 45-day period, which concludes June 6, 2011. Following receipt of comments on the SDEIS and subsequent publication of a Final Environmental Impact Statement, the DOS will consult with other U.S. federal agencies during a 90-

day period to determine if granting approval for the U.S. Gulf Coast Expansion is in the national interest. The DOS has indicated it will make a final decision regarding the Presidential Permit prior to the end of 2011.

The capital cost of Keystone, including the U.S. Gulf Coast Expansion, is estimated to be US$13 billion. At March 31, 2011, US$7.6 billion had been invested, including US$1.5 billion related to the U.S. Gulf Coast Expansion. The remainder is expected to be invested between now and the in-service date of the expansion, which is expected in 2013. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with Keystone's long-term committed shippers.

On March 31, 2011, Keystone filed revised fixed tolls for the Wood River/Patoka section of the system with both the NEB and the FERC. The Company expects the revised tolls, which reflect the final project costs of the Wood River/Patoka section, to be effective May 1, 2011, subject to regulatory approval.

In 2010, three entities, each of which had entered into Transportation Service Agreements for the Cushing Extension, had filed separate Statements of Claim against certain of TCPL's Keystone subsidiaries in the Alberta Court of Queen's Bench seeking declaratory relief or, alternatively, damages in varying amounts. All of the claims have been discontinued on a without-cost and without-liability basis.

Energy

Sundance A

In December 2010, the Sundance A Units 1 and 2 were withdrawn from service for testing 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 replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated.

TCPL does not agree with TransAlta's determination on either the force majeure claim or the destruction claim and has disputed both matters under the binding dispute resolution process provided in the PPA. As the limited information TCPL has received to date does not support these claims, TCPL continues to record revenues and costs under the PPA as though this event was a normal plant outage.

Bruce

Refurbishment work on Bruce A Units 1 and 2 continues with the connection of the refurbished Unit 2 reactor to plant systems. Plant commissioning is underway on Unit 2 and will accelerate in second quarter 2011 when construction activities are essentially complete. Fuel Channel Assembly (FCA) is underway on Unit 1, with completion expected in second quarter 2011. The installation of these FCAs is the final stage of Atomic Energy of Canada Limited's work on the reactors.

Subject to regulatory approval, Bruce Power expects to load fuel into Unit 2 in second quarter 2011 and achieve a first synchronization of the generator to the electrical grid by the end of 2011, with commercial operation expected to occur in first quarter 2012. Bruce Power expects to load fuel into Unit 1 in third quarter 2011, with a first synchronization of the generator during first quarter 2012 and commercial operation expected to occur during third quarter 2012. TCPL's share of the total capital cost is expected to be approximately $2.4 billion of which $2.1 billion was incurred as of March 31, 2011.

Coolidge

Construction of the US$500 million Coolidge generating station is complete. The 575 MW simple-cycle, natural gas-fired peaking power facility is expected to be placed in service on May 1, 2011.

Ravenswood

The parameters that drive U.S. Power capacity prices are reset periodically and are affected by a number of factors, including the cost of entering the market, reflected in administratively-set demand curves, available supply and fluctuations in forecast demand. With the downturn in the economy, there has been a decrease in demand that, combined with increased supply, has put downward pressure on capacity prices. On January 28, 2011, the FERC issued a decision in a rate filing made by the New York Independent System Operator (NYISO) relating to the periodic reset of the demand curves. The FERC made several determinations related to such demand curves and ordered the NYISO to make revisions in a compliance filing no later than March 29, 2011. The NYISO issued revisions to its compliance filing on March 29, 2011, to which the FERC has not yet issued a decision. While TCPL expects the FERC's decision to result in higher demand curve price levels and to positively affect capacity prices, it is unclear what the specific impact will be until the NYISO compliance filing is fully implemented.

Oakville

In September 2009, the OPA awarded TCPL a 20-year Clean Energy Supply contract to build, own and operate a 900 MW power generating station in Oakville, Ontario. TCPL expected to invest approximately $1.2 billion in the natural gas-fired, combined-cycle plant. In October 2010, the Government of Ontario announced that it would not proceed with the Oakville generating station. TCPL is negotiating a settlement with the OPA that would terminate the Clean Energy Supply contract and compensate TCPL for the economic consequences associated with the contract's termination.

Cartier Wind

Construction continues on the Cartier Wind project in Québec. The 58 MW Montagne-Sèche project and the 101 MW first phase of the Gros-Morne wind farm are expected to be operational in December 2011. The 111 MW second phase of Gros-Morne is expected to be operational in December 2012. These are the fourth and fifth Québec-based wind farms of Cartier Wind, which is 62 per cent owned by TCPL. All of the 590 MW of power to be produced by Cartier Wind is sold under a 20-year power purchase arrangement to Hydro-Québec.

Share Information

At April 26, 2011, TCPL had 675 million common shares, four million Series U and four million Series Y preferred shares issued and outstanding.

Selected Quarterly Consolidated Financial Data[1]

(unaudited)	**2011**	2010				2009		
(millions of dollars except per share amounts)	**First**	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**2,243**	2,057	2,129	1,923	1,955	1,986	2,049	1,984
Net income attributable to controlling interests	**414**	276	387	292	301	384	343	316
Share Statistics								
Net income per common share – Basic and Diluted	**$0.60**	**$0.40**	**$0.57**	**$0.43**	**$0.46**	**$0.58**	**$0.55**	**$0.52**

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

Factors Affecting Quarterly Financial Information

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities, annual revenues, EBIT and TCPL's net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and TCPL's net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Oil Pipelines, which consists of the Company's investment in the Keystone crude oil pipeline, annual revenues and TCPL's net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues, EBIT and TCPL's net income during any particular fiscal year remain relatively stable with fluctuations resulting from 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 TCPL's net income are affected by seasonal weather conditions, customer demand, market prices, capacity payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

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

- First Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of Keystone in February 2011. Energy's EBIT included net unrealized losses of $18 million pre-tax ($11 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

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

- Third Quarter 2010, Natural Gas Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 – 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized gains of $4 million pre-tax ($3 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Second Quarter 2010, Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of $58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.

- First Quarter 2010, Energy's EBIT included net unrealized losses of $49 million pre-tax ($32 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Fourth Quarter 2009, Natural Gas Pipelines EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TCPL's reduced ownership interest in PipeLines LP, which was caused by PipeLines LP's issue of common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.

- Third Quarter 2009, Energy's EBIT included net unrealized gains of $14 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Second Quarter 2009, Energy's EBIT included net unrealized losses of $7 million pre-tax ($5 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Energy's EBIT also included contributions from Portlands Energy, which was placed in service in April 2009, and the negative impact of Western Power's lower overall realized power prices.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	2010
Revenues	**2,243**	1,955
Operating and Other Expenses		
Plant operating costs and other	**759**	747
Commodity purchases resold	**277**	256
Depreciation and amortization	**370**	343
	1,406	1,346
Financial Charges/(Income)		
Interest expense	**239**	194
Interest expense of joint ventures	**16**	16
Interest income and other	**(33)**	(24)
	222	186
Income before Income Taxes	**615**	423
Income Taxes Expense		
Current	**100**	80
Future	**71**	17
	171	97
Net Income	**444**	326
Net Income Attributable to Non-Controlling Interests	**30**	25
Net Income Attributable to Controlling Interests	**414**	301
Preferred Share Dividends	**6**	6
Net Income Attributable to Common Shares	**408**	295

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	 2010
Net Income	**444**	326
Other Comprehensive (Loss)/Income, Net of Income Taxes		
Change in foreign currency translation gains and losses on investments in foreign operations[(1)]	**(98)**	(147)
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[(2)]	**49**	59
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**(51)**	(76)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[(4)]	**44**	(1)
Other Comprehensive (Loss)/Income	**(56)**	(165)
Comprehensive Income	**388**	161
Comprehensive Income Attributable to Non-Controlling Interests	**33**	24
Comprehensive Income Attributable to Controlling Interests	**355**	137
Preferred Share Dividends	**6**	6
Comprehensive Income Attributable to Common Shares	**349**	131

(1) Net of income tax expense of $29 million for the three months ended March 31, 2011 (2010 – expense of $30 million).
(2) Net of income tax expense of $19 million for the three months ended March 31, 2011 (2010 – expense of $26 million).
(3) Net of income tax recovery of $18 million for the three months ended March 31, 2011 (2010 – recovery of $57 million).
(4) Net of income tax expense of $24 million for the three months ended March 31, 2011 (2010 – expense of $1 million).

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	 2010
Cash Generated From Operations		
Net income	**444**	326
Depreciation and amortization	**370**	343
Future income taxes	**71**	17
Employee future benefits funding in excess of expense	**(11)**	(32)
Other	**21**	58
	895	712
Decrease in operating working capital	**110**	116
Net cash provided by operations	**1,005**	828
Investing Activities		
Capital expenditures	**(784)**	(1,276)
Deferred amounts and other	**5**	(216)
Net cash used in investing activities	**(779)**	(1,492)
Financing Activities		
Dividends on common and preferred shares	**(285)**	(266)
Advances from/(to) parent	**84**	383
Distributions paid to non-controlling interests	**(21)**	(21)
Notes payable issued, net	**133**	432
Long-term debt issued, net of issue costs	**-**	10
Reduction of long-term debt	**(321)**	(141)
Long-term debt of joint ventures issued	**-**	8
Reduction of long-term debt of joint ventures	**(11)**	(26)
Net cash (used in)/provided by financing activities	**(421)**	379
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(13)**	(17)
Decrease in Cash and Cash Equivalents	**(208)**	(302)
Cash and Cash Equivalents		
Beginning of period	**752**	979
Cash and Cash Equivalents		
End of period	**544**	677
Supplementary Cash Flow Information		
Income taxes paid, net of refunds	**87**	4
Interest paid	**262**	243

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**March 31, 2011**	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	**544**	752
Accounts receivable	**1,266**	1,280
Due from TransCanada Corporation	**1,279**	1,363
Inventories	**402**	425
Other	**602**	777
	4,093	4,597
Plant, Property and Equipment	**36,113**	36,244
Goodwill	**3,488**	3,570
Regulatory Assets	**1,486**	1,512
Intangibles and Other Assets	**2,070**	2,026
	47,250	47,949
LIABILITIES		
Current Liabilities		
Notes payable	**2,192**	2,092
Accounts payable	**1,948**	2,247
Accrued interest	**366**	361
Current portion of long-term debt	**574**	894
Current portion of long-term debt of joint ventures	**64**	65
	5,144	5,659
Due to TransCanada Corporation	**2,703**	2,703
Regulatory Liabilities	**334**	314
Deferred Amounts	**689**	694
Future Income Taxes	**3,316**	3,250
Long-Term Debt	**16,753**	17,028
Long-Term Debt of Joint Ventures	**785**	801
Junior Subordinated Notes	**962**	985
	30,686	31,434
SHAREHOLDERS' EQUITY		
Controlling interests	**15,804**	15,747
Non-controlling interests	**760**	768
	16,564	16,515
	47,250	47,949

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges	Total
Balance at December 31, 2010	**(683)**	**(194)**	**(877)**
Change in foreign currency translation gains and losses on investments in foreign operations[(1)]	**(98)**	**-**	**(98)**
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[(2)]	**49**	**-**	**49**
Change in gains and losses on derivative instruments designated as cash flow hedges[(3)]	**-**	**(52)**	**(52)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[(4)(5)]	**-**	**42**	**42**
Balance at March 31, 2011	**(732)**	**(204)**	**(936)**

Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on investments in foreign operations[(1)]	(147)	-	(147)
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[(2)]	59	-	59
Changes in gains and losses on derivative instruments designated as cash flow hedges[(3)]	-	(77)	(77)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[(4)]	-	1	1
Balance at March 31, 2010	(680)	(116)	(796)

(1) Net of income tax expense of $29 million for the three months ended March 31, 2011 (2010 – expense of $30 million).
(2) Net of income tax expense of $19 million for the three months ended March 31, 2011 (2010 – expense of $26 million).
(3) Net of income tax recovery of $18 million for the three months ended March 31, 2011 (2010 – recovery of $57 million).
(4) Net of income tax expense of $24 million for the three months ended March 31, 2011 (2010 – expense of $1 million).
(5) Losses related to cash flow hedges reported in Accumulated Other Comprehensive (Loss)/Income and expected to be reclassified to Net Income in the next 12 months are estimated to be $86 million ($56 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

See accompanying notes to the consolidated financial statements.

Consolidated Shareholders' Equity

(unaudited) *(millions of dollars)*	Three months ended March 31 **2011**	2010
Common Shares		
Balance at beginning and end of period	**11,636**	10,649
Preferred Shares		
Balance at beginning and end of period	**389**	389
Contributed Surplus		
Balance at beginning of period	**341**	335
Other	**-**	2
Balance at end of period	**341**	337
Retained Earnings		
Balance at beginning of period	**4,258**	4,131
Net income attributable to controlling interests	**414**	301
Common share dividends	**(292)**	(275)
Preferred share dividends	**(6)**	(6)
Balance at end of period	**4,374**	4,151
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	**(877)**	(632)
Other comprehensive (loss)/income	**(59)**	(164)
Balance at end of period	**(936)**	(796)
	3,438	3,355
Shareholders' Equity Attributable to Controlling Interests	**15,804**	14,730
Shareholders' Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**768**	785
Net income attributable to non-controlling interests		
PipeLines LP	**26**	22
Portland	**4**	3
Other comprehensive income/(loss) attributable to non-controlling interests	**3**	(1)
Distributions to non-controlling interests	**(21)**	(21)
Other	**(20)**	(21)
Balance at end of period	**760**	767
Total Shareholders' Equity	**16,564**	15,497

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

(Unaudited)

1. Significant Accounting Policies

The consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook, which is discussed further in Note 2. The accounting policies applied are consistent with those outlined in TCPL's annual audited Consolidated Financial Statements for the year ended December 31, 2010. These Consolidated Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2010 audited Consolidated Financial Statements included in TCPL's 2010 Annual Report. Unless otherwise indicated, "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TCPL's 2010 Annual Report. Amounts are stated in Canadian dollars unless otherwise indicated.

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities, annual revenues and TCPL's net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and TCPL's net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

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

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and TCPL's net income are affected by seasonal weather conditions, customer demand, market prices, capacity payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

2. Changes in Accounting Policies

Changes in Accounting Policies for 2011

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

Future Accounting Changes

U.S. GAAP/International Financial Reporting Standards
The CICA's Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), effective January 1, 2011.

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

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

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

US GAAP Conversion Project
Effective January 1, 2012, the Company will begin reporting under U.S. GAAP. The accounting policies and financial impact of adopting U.S. GAAP are consistent with that currently reported in the Company's publicly-filed "Reconciliation to United States GAAP." Significant changes to existing systems and processes

are not required to implement U.S. GAAP as the Company's primary accounting standard since TCPL prepares and files a "Reconciliation to U.S. GAAP".

TCPL's IFRS conversion team has been redeployed to support the conversion to U.S. GAAP. The conversion team is led by a multi-disciplinary Steering Committee that provides directional leadership for the adoption of U.S. GAAP. Management also updates TCPL's Audit Committee on the progress of the U.S. GAAP project at each Audit Committee meeting.

3. Segmented Information

For the three months ended March 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2011	2010	Oil Pipelines[1] 2011	2010	Energy 2011	2010	Corporate 2011	2010	Total 2011	2010
Revenues	1,129	1,129	135	-	979	826	-	-	2,243	1,955
Plant operating costs and other	(333)	(361)	(36)	-	(366)	(360)	(24)	(26)	(759)	(747)
Commodity purchases resold	-	-	-	-	(277)	(256)	-	-	(277)	(256)
Depreciation and amortization	(244)	(253)	(23)	-	(100)	(90)	(3)	-	(370)	(343)
	552	515	76	-	236	120	(27)	(26)	837	609
Interest expense									(239)	(194)
Interest expense of joint ventures									(16)	(16)
Interest income and other									33	24
Income taxes									(171)	(97)
Net Income									444	326
Net Income Attributable to Non-Controlling Interests									(30)	(25)
Net Income Attributable to Controlling Interests									414	301
Preferred Share Dividends									(6)	(6)
Net Income Attributable to Common Shares									408	295

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

Total Assets

(unaudited) *(millions of dollars)*	**March 31, 2011**	December 31, 2010
Natural Gas Pipelines	**23,201**	23,592
Oil Pipelines	**8,603**	8,501
Energy	**12,693**	12,847
Corporate	**2,753**	3,009
	47,250	47,949

4. Long-Term Debt

In the three months ended March 31, 2011, the Company capitalized interest related to capital projects of $97 million (2010 - $134 million).

5. Financial Instruments and Risk Management

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

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets, and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At March 31, 2011, there were no significant amounts past due or impaired.

At March 31, 2011, the Company had a credit risk concentration of $297 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions.

Natural Gas Storage Commodity Price Risk

At March 31, 2011, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $49 million (December 31, 2010 - $49 million). The change in the fair value adjustment of proprietary natural gas inventory in storage in the three months ended March 31, 2011 resulted in net pre-tax unrealized gains of $2 million (2010 - losses of $24 million), which was recorded as an increase in Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three months ended March 31, 2011 resulted in net pre-tax unrealized losses of $7 million (2010 – gains of $3 million), which was included in Revenues.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TCPL's consolidated VaR was $14 million at March 31, 2011 (December 31, 2010 – $12 million). The increase from December 31, 2010 was primarily due to increased Alberta power forward prices as well as increased price volatility in the Alberta power market.

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 March 31, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.5 billion (US$9.8 billion) and a fair value of $10.8 billion (US$11.1 billion). At March 31, 2011, $251 million (December 31, 2010 - $181 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**March 31, 2011** Fair Value[(1)]	**March 31, 2011** Notional or Principal Amount	December 31, 2010 Fair Value[(1)]	December 31, 2010 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2017)	**246**	**US 3,150**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2011)	**5**	**US 550**	2	US 100
	251	**US 3,700**	181	US 2,900

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**March 31, 2011** Carrying Amount	**March 31, 2011** Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value
Financial Assets[(1)]				
Cash and cash equivalents	**544**	**544**	752	752
Accounts receivable and other[(2)(3)]	**1,585**	**1,619**	1,564	1,604
Due from TransCanada Corporation	**1,279**	**1,279**	1,363	1,363
Available-for-sale assets[(2)]	**25**	**25**	20	20
	3,433	**3,467**	3,699	3,739
Financial Liabilities[(1)(3)]				
Notes payable	**2,192**	**2,192**	2,092	2,092
Accounts payable and deferred amounts[(4)]	**1,125**	**1,125**	1,444	1,444
Due to TransCanada Corporation	**2,703**	**2,703**	2,703	2,703
Accrued interest	**366**	**366**	361	361
Long-term debt	**17,327**	**20,416**	17,922	21,523
Junior subordinated notes	**962**	**969**	985	992
Long-term debt of joint ventures	**849**	**944**	866	971
	25,524	**28,715**	26,373	30,086`

(1) Consolidated Net Income in first quarter 2011 included losses of $9 million (2010 – losses of $7 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At March 31, 2011, the Consolidated Balance Sheet included financial assets of $1,266 million (December 31, 2010 – $1,280 million) in Accounts Receivable, $38 million (December 31, 2010 – $40 million) in Other Current Assets and $306 million (December 31, 2010 - $264 million) in Intangibles and Other Assets.

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

(4) At March 31, 2011, the Consolidated Balance Sheet included financial liabilities of $1,093 million (December 31, 2010 – $1,507 million) in Accounts Payable and $32 million (December 31, 2010 - $30 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

March 31, 2011 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading(1)				
Fair Values(2)				
Assets	**$175**	**$123**	**$10**	**$17**
Liabilities	**$(132)**	**$(154)**	**$(16)**	**$(18)**
Notional Values				
Volumes(3)				
Purchases	**21,828**	**169**	**-**	**-**
Sales	**24,462**	**132**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**836**
U.S. dollars	**-**	**-**	**US 1,839**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2011(4)	**$(1)**	**$(16)**	**$2**	**$(1)**
Net realized gains/(losses) in the three months ended March 31, 2011(4)	**$3**	**$(26)**	**$21**	**$2**
Maturity dates	**2011-2015**	**2011-2015**	**2011-2012**	**2011-2016**
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(2)				
Assets	**$75**	**$6**	**$-**	**$9**
Liabilities	**$(177)**	**$(19)**	**$(56)**	**$(19)**
Notional Values				
Volumes(3)				
Purchases	**18,273**	**16**	**-**	**-**
Sales	**7,906**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 120**	**US 1,000**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized losses in the three months ended March 31, 2011(4)	**$(38)**	**$(3)**	**$-**	**$(5)**
Maturity dates	**2011-2015**	**2011-2013**	**2011- 2014**	**2011-2015**

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

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in gigawatt hours (GWh) and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments 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 $9 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three months ended March 31, 2011 were $2 million and were included in Interest Expense. In first quarter 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three months ended March 31, 2011, Net Income included losses of $3 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. For the three months ended March 31, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

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

	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values(1)(2)				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values(2)				
Volumes(3)				
Purchases	15,610	158	-	-
Sales	18,114	96	-	-
Canadian dollars	-	-	-	736
U.S. dollars	-	-	US 1,479	US 250
Cross-currency	-	-	47/ US 37	-
Net unrealized (losses)/gains in the three months ended March 31, 2010(4)	$(16)	$2	-	$(4)
Net realized gains/(losses) in the three months ended March 31, 2010(4)	$22	$(12)	$8	$(4)
Maturity dates(2)	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(1)(2)				
Assets	$112	$5	$-	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values(2)				
Volumes(3)				
Purchases	16,071	17	-	-
Sales	10,498	-	-	-
U.S. dollars	-	-	US 120	US 1,125
Cross-currency	-	-	136/US 100	-
Net realized losses in the three months ended March 31, 2010(4)	($7)	$(3)	-	$(10)
Maturity dates(2)	2011-2015	2011-2013	2011-2014	2011-2015

(1) Fair values equal carrying values.
(2) As at December 31, 2010.
(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments 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 $8 million and a notional amount of US$250 million at December 31, 2010. Net realized gains

on fair value hedges for the three months ended March 31, 2010 were $1 million and were included in Interest Expense. In first quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three months ended March 31, 2010, Net Income included losses of $8 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. For the three months ended March 31, 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**March 31, 2011**	December 31, 2010
Current		
Other current assets	**243**	273
Accounts payable	**(326)**	(337)
Long-term		
Intangibles and other assets	**423**	374
Deferred amounts	**(265)**	(282)

Fair Value Hierarchy

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

There were no transfers between Level I and Level II in first quarter 2011 and 2010. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

(unaudited) (millions of dollars, pre-tax)	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010
Natural Gas Inventory	**-**	-	**49**	49	**-**	-	**49**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**26**	28	**-**	-	**26**	28
Foreign exchange contracts	**15**	10	**246**	179	**-**	-	**261**	189
Power commodity contracts	**-**	-	**232**	269	**4**	5	**236**	274
Natural gas commodity contracts	**72**	93	**53**	56	**-**	-	**125**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(37)**	(47)	**-**	-	**(37)**	(47)
Foreign exchange contracts	**(14)**	(11)	**(58)**	(54)	**-**	-	**(72)**	(65)
Power commodity contracts	**-**	-	**(282)**	(299)	**(13)**	(8)	**(295)**	(307)
Natural gas commodity contracts	**(140)**	(178)	**(29)**	(15)	**-**	-	**(169)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**25**	20	**-**	-	**-**	-	**25**	20
	(42)	(66)	**200**	166	**(9)**	(3)	**149**	97

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

For the three months ended March 31 (unaudited) (millions of dollars, pre-tax)	Derivatives	
	2011	2010
Balance at beginning of period	**(3)**	(2)
New contracts[2]	**1**	(10)
Transfers out of Level III[3]	**(2)**	(5)
Settlements	**-**	(1)
Change in unrealized gains recorded in Net Income	**-**	5
Change in unrealized (losses)/gains recorded in Other Comprehensive Income	**(5)**	8
Balance at end of period	**(9)**	(5)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) For the three months ended March 31, 2011, there were no amounts (2010 – loss of $1 million) included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date.
(3) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $7 million decrease or increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at March 31, 2011.

6. Employee Future Benefits

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

Three months ended March 31	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2011**	2010	**2011**	2010
Current service cost	**14**	12	**-**	-
Interest cost	**23**	23	**2**	2
Expected return on plan assets	**(28)**	(27)	**-**	-
Amortization of net actuarial loss	**6**	2	**-**	-
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**16**	11	**2**	2

7. Contingencies

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues in the first three months of 2011 are expected to be repaid.

8. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

		2011		2010	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Discount Notes	2011	**2,572**	**1.4%**	2,566	1.4%
Credit Facility		**(1,293)**	**3.0%**	(1,203)	3.0%
		1,279		1,363	

The following amounts are included in Due to TransCanada Corporation:

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

9. Subsequent Events

On April 26, 2011, the Company announced it entered into agreements to sell a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to PipeLines LP for an aggregate purchase price of US$605 million, which includes US$81 million of long-term debt or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively. The sale is expected to close in May 2011 and is subject to certain closing conditions.

At the end of April 2011, PipeLines LP announced an underwritten public offering of 6,300,000 common units at US$47.58 per unit. Gross proceeds of approximately US$300 million from this offering will be used to partially fund the acquisition with the balance funded by a draw on PipeLines LP's committed and available US$400 million bridge loan facility and a draw on PipeLines LP's US$250 million committed and available senior revolving credit facility. The underwriters were also granted a 30-day option to purchase an additional 945,000 common units at the same price. The offering is expected to close on May 3, 2011.

As part of this offering, TCPL will make a capital contribution of US$6 million to maintain its two per cent general partnership interest in PipeLines LP. Assuming the underwriters exercise their option to purchase additional units, TCPL's ownership in PipeLines LP is expected to be approximately 33.3 per cent.

TCPL welcomes questions from shareholders and potential investors. Please telephone:

Investor Relations, at (800) 361-6522 (Canada and U.S. Mainland) or direct dial David Moneta/Terry Hook at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: Terry Cunha/Shawn Howard (403) 920-7859 or (800) 608-7859.

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