TransCanada Reports First Quarter Results, Bruce Power Refurbishment Nearing Completion

CALGARY, Alberta – **April 27, 2012** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for first quarter 2012 of $363 million or $0.52 per share. Net income attributable to common shares for first quarter 2012 was $352 million or $0.50 per share. TransCanada's Board of Directors also declared a quarterly dividend of $0.44 per common share for the quarter ending June 30, 2012, equivalent to $1.76 per common share on an annualized basis.

"TransCanada continued to produce solid earnings in a challenging environment," said Russ Girling, TransCanada's president and chief executive officer. "A very warm winter, historically low natural gas prices and planned maintenance outages at Bruce Power impacted earnings in the first quarter of 2012. The return to service of two refurbished nuclear reactors at Bruce Power and the contribution from other new assets position TransCanada well for the future. As gas and power prices recover, combined with the completion of our current $13 billion capital program, I fully expect TransCanada will continue to grow cash flow, earnings and dividends in the years ahead."

Over the next three years, TransCanada expects to complete $13 billion of projects that are in the advanced stages of development - $7.8 billion in oil pipelines, $2.2 billion in natural gas pipelines and $3 billion in energy. They include: the re-start of two reactors at Ontario's Bruce nuclear facility, the Keystone Gulf Coast Project and Keystone XL, the Keystone Bakken Marketlink Project, the Keystone Hardisty Terminal Project, additional extensions and expansions of the Alberta System, the Tamazunchale natural gas pipeline extension in Mexico, the final phase of the Cartier Wind power project in Québec and the acquisition of nine Ontario solar projects.

To date, the Company has spent approximately $6 billion on these low-risk energy infrastructure assets and is well positioned to fund the remainder of this capital program from internally generated cash flow and debt capacity. TransCanada expects these assets to generate significant, sustained earnings and cash flow growth and deliver superior returns to its shareholders.

Highlights
(All financial figures are unaudited and in Canadian dollars unless noted otherwise)

- First quarter financial results
  - Comparable earnings of $363 million or $0.52 per share
  - Net income attributable to common shares of $352 million or $0.50 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.1 billion
  - Funds generated from operations of $841 million
- Declared a quarterly dividend per common share of $0.44 for the quarter ending June 30
- Bruce Power entered the final phase of the refurbishment and re-start project. TransCanada's share of the project costs is expected to be approximately $2.4 billion
- Advanced a number of initiatives in the Oil Pipelines business
  - Announced plans to build the US$2.3 billion Gulf Coast Project to transport crude oil from Cushing, Oklahoma to Gulf Coast refineries
  - Announced commitment to re-file a Presidential Permit application for the Keystone XL Project from the U.S./Canada border to Steele City, Nebraska

- Launched and concluded a binding open season for the Keystone Hardisty Terminal to store and deliver crude oil to the Keystone Pipeline System

- Awarded a contract to build a US$500 million extension of the Tamazunchale natural gas pipeline in Mexico

Comparable earnings for first quarter 2012 were $363 million or $0.52 per share compared to $423 million or $0.61 per share for the same period in 2011. Incremental earnings from Keystone and other recently commissioned assets were more than offset by lower contributions from Bruce Power related to planned maintenance outages, reduced revenues from U.S. natural gas pipelines and natural gas storage, higher interest expense as a result of lower capitalized interest and reduced contributions from the Canadian Mainline and U.S. Power.

Net income attributable to common shares for first quarter 2012 was $352 million or $0.50 per share compared to $411 million or $0.59 per share in first quarter 2011.

Notable recent developments in Oil Pipelines, Natural Gas Pipelines, Energy and Corporate include:

Oil Pipelines:

- The Company announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Project has its own independent value to the marketplace and will be constructed as the stand-alone Gulf Coast Project, not part of the Presidential Permit process. The approximate cost of the 36-inch line is US$2.3 billion and, subject to regulatory approvals, TransCanada expects the Gulf Coast Project to be in service in mid to late 2013. As of March 31, 2012, US$800 million has been invested in the project. Included in the US$2.3 billion cost is US$300 million for the 76-kilometre (km) (47-mile) Houston Lateral pipeline that will transport oil to Houston refineries.

  U.S. crude oil production has been growing significantly in States such as Oklahoma, Texas, North Dakota and Montana. Producers do not have access to enough pipeline capacity to move this production to the large refining market at the U.S. Gulf Coast. The Gulf Coast Project will address this constraint.

- Also in February, TransCanada sent a letter to the U.S. Department of State (DOS) informing the Department the Company plans to re-file a Presidential Permit application (cross border permit) in the near future for the Keystone XL Project from the U.S./Canada border in Montana to Steele City, Nebraska. TransCanada noted it would supplement that application with an alternative route in Nebraska as soon as that route is selected.

  The application will include the already reviewed route in Montana and South Dakota. The over three year environmental review for Keystone XL completed last summer was the most comprehensive process ever for a cross border pipeline. Based on that work, TransCanada expects its cross border permit should be processed expeditiously and a decision made once a new route in Nebraska is determined.

  Earlier this month, legislation was passed in Nebraska and signed into law by the Governor that enabled TransCanada to re-engage with the State's Department of Environmental Quality (DEQ), allowing the Company to continue to work collaboratively in determining an alternative route for Keystone XL that avoids the Sandhills. Alternative routing corridors and a preferred corridor were submitted to the DEQ April 18, 2012. The Department will now oversee the public comment and review process as TransCanada develops a specific alternate route.

The capital cost of Keystone XL is estimated to be US$5.3 billion, with US$1.5 billion having been invested as of March 31, 2012. The remainder will be spent between now and the in-service date of the expansion, which is expected by late 2014 or early 2015.

- In March 2012, TransCanada launched and concluded an open season to obtain binding commitments for the Keystone Hardisty Terminal. The two million barrel project located at Hardisty, Alberta will provide new infrastructure for Western Canadian producers and access to the Keystone Pipeline System. TransCanada is currently reviewing the results of the open season. The Keystone Hardisty Terminal is expected to be operational by late 2014 or early 2015.

Natural Gas Pipelines:

- The National Energy Board (NEB) approved $330 million of expansion projects for the Alberta System in first quarter 2012 which is a portion of the previously reported $810 million of projects for the Alberta System filed in 2011 – the balance of which are still awaiting approval.

  TransCanada's Alberta System has incremental, firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeast B.C. by 2014. Further requests for additional volumes on the Alberta System from the northwest portion of the Western Canada Sedimentary Basin (WCSB) have been received.

  In addition, infrastructure to connect WCSB supply to markets continues to be pursued, particularly to support further development of Alberta oil sands production and to supply proposed liquefied natural gas (LNG) export facilities on the West Coast.

  During the first four months of 2012, TransCanada has substantially completed 10 separate pipeline projects for the Alberta System at a cost of approximately $600 million.

- On June 4, 2012, an NEB hearing will begin to discuss TransCanada's application to change the business structure and the terms and conditions of service for the Canadian Mainline, including addressing tolls for 2012 and 2013. The hearing is expected to conclude in September with a decision in late 2012 or early 2013.

  TransCanada is working to construct new pipeline infrastructure to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin. The NEB is continuing to assess the application for the project that was filed late last fall. Assuming the project receives approval to proceed, construction is scheduled to begin in early July 2012, with planned completion in November 2012. The capital cost of the Marcellus Facilities Expansion is expected to be approximately $130 million.

  An open season to attract new capacity on the Canadian Mainline to capture additional Marcellus gas supply will close in May. It is being held in response to shippers who have expressed interest in acquiring additional transport capacity.

- On February 24, 2012, the Company was chosen to build, own and operate the Tamazunchale Pipeline Extension in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract with the Comisión Federal de Electricidad (CFE), Mexico's state-owned power company.

TransCanada anticipates investing approximately US$500 million in the pipeline and expects it will be operational in the first quarter of 2014. The 235-km (146-mile) long pipeline has a contracted capacity of 630 million cubic feet a day (mmcf/d). The pipeline will originate at the end of TransCanada's existing Tamazunchale Pipeline, eventually connecting with Mexico's existing pipeline grid and serve a CFE combined-cycle power generating facility.

The Tamazunchale Pipeline Extension demonstrates TransCanada's continued commitment to developing Mexico's energy infrastructure to meet growing requirements for increased natural gas supply. The Mexican government recently announced a number of additional natural gas infrastructure projects for the country. This infrastructure will assist Mexico in meeting growing demand and support greenhouse gas reduction initiatives by enabling access to natural gas as a replacement fuel for heavy oil. TransCanada intends to continue to pursue future development opportunities in Mexico.

- The Alaska North Slope producers (Exxon Mobil Corporation, ConocoPhillips and BP), along with TransCanada through its participation in the Alaska Pipeline Project, announced in March 2012 the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources through an LNG option. This would involve construction of a natural gas pipeline from the North Slope to Valdez, Alaska where the gas would be liquefied and shipped to international markets.

Energy:

- Bruce Power received authorization from the Canadian Nuclear Safety Commission on March 16, 2012 to power up the Unit 2 reactor, effectively ending the construction and commissioning phases of the project. This positive development represented the final major step necessary toward bringing the reactor into service.

  The reactor is presently producing steam and final safety checks are being conducted. The company anticipates the unit will start commercial operations in second quarter 2012. Refurbishment of the Unit 1 reactor at Bruce Power is also progressing and it is expected to begin commercial operations in mid-third quarter 2012.

  TransCanada's share of the net capital cost of the refurbishment is expected to be approximately $2.4 billion. Once the work is complete, Bruce Power will be one of the world's largest nuclear facilities, generating more than 6,200 megawatts (MW) or about 25 per cent of Ontario's power.

- The 111 MW second phase of Gros-Morne is expected to be operational in December 2012. Its construction will signal the completion of the 590 MW, five-phase Cartier Wind project in Québec. The project is 62 per cent owned by TransCanada and all of the power produced by Cartier Wind is sold under a 20-year power purchase arrangement (PPA) to Hydro-Québec.

- Late in 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately $470 million. All nine projects have 20-year power purchase agreements with the Ontario Power Authority.

  Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. utilizing their photovoltaic panels. TransCanada will purchase each project after they begin commercial operation and meet certain milestones. TransCanada anticipates the projects will be operational between late 2012 and mid-2013.

- TransAlta filed a force majeure claim in January 2011 following the shut down of Sundance A Units 1 and 2 in December 2010. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2 and that the Sundance A PPA should be terminated.

  TransCanada has disputed both the force majeure and economic destruction claims. An arbitration process to resolve the matter began in early April and is expected to conclude in May, with a decision anticipated in mid-2012.

  TransCanada has continued to record revenues and costs as it considers this event to be an interruption of supply. The Company believes the matter will be resolved in its favour.

Corporate:

- In March 2012, TransCanada PipeLines Limited issued Senior Notes of US$500 million maturing on March 2, 2015 and bearing interest at an annual rate of 0.875 per cent. The net proceeds of this offering were used for general corporate purposes and to reduce short-term indebtedness.

- The Board of Directors of TransCanada declared a quarterly dividend of $0.44 per share for the quarter ending June 30, 2012 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.76 per common share on an annual basis.

- As previously disclosed, TransCanada adopted U.S. generally accepted accounting principles (U.S. GAAP) effective January 1, 2012. Accordingly, first quarter 2012 financial information, along with comparative financial information for 2011, has been prepared in accordance with U.S. GAAP.

Teleconference – Audio and Slide Presentation:

TransCanada will hold a teleconference and webcast to discuss its 2012 first quarter financial results. Russ Girling, TransCanada president and chief executive officer and Don Marchand, executive vice-president and chief financial officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments before opening the call to questions from analysts and members of the media.

Event:
TransCanada 2012 first quarter financial results teleconference and webcast

Date:
Friday, April 27, 2012

Time:
1 p.m. mountain daylight time (MDT) / 3 p.m. eastern daylight time (EDT)

Analysts, members of the media and other interested parties are invited to participate by calling 866.226.1792 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EDT) May 4, 2012. Please call 905.694.9451 or 800.408.3053 (North America only) and enter pass code 8130635.

With more than 60 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,500 kilometres (42,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 380 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 10,800 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com or check us out on Twitter @TransCanada.

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Media Enquiries:	Shawn Howard	403.920.7859 800.608.7859
Investor & Analyst Enquiries:	David Moneta/Terry Hook/Lee Evans	403.920.7911 800.361.6522

First Quarter 2012 Financial Highlights

Operating Results

Three months ended March 31 *(unaudited)* *(millions of dollars)*	**2012**	2011
Revenues	**1,911**	1,868
Comparable EBITDA[(1)]	**1,113**	1,163
Net Income Attributable to Common Shares	**352**	411
Comparable Earnings[(1)]	**363**	423
Cash Flows		
Funds generated from operations[(1)]	**841**	815
(Increase)/decrease in operating working capital	**(169)**	19
Net cash provided by operations	**672**	834
Capital Expenditures	**464**	567

Common Share Statistics

Three months ended March 31 *(unaudited)*	**2012**	2011
Net Income per Common Share - Basic	**$0.50**	$0.59
Comparable Earnings per Common Share[(1)]	**$0.52**	$0.61
Dividends Declared per Common Share	**$0.44**	$0.42
Basic Common Shares Outstanding (millions)		
Average for the period	**704**	698
End of period	**704**	700

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA, Comparable Earnings, Funds Generated from Operations and Comparable Earnings per Share.

Quarterly Report to Shareholders

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) dated April 26, 2012 should be read in conjunction with the accompanying unaudited Condensed Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) for the three months ended March 31, 2012. The condensed consolidated financial statements of the Company have been prepared in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP). Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook (CGAAP), have been adjusted as necessary to be compliant with the Company's policies under U.S. GAAP, which is discussed further in the Changes in Accounting Policies section in this MD&A. This MD&A should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TransCanada's 2011 Annual Report, as prepared in accordance with CGAAP, for the year ended December 31, 2011. Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation's profile. "TransCanada" or "the Company" includes TransCanada Corporation 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 TransCanada's 2011 Annual Report.

Forward-Looking Information

This MD&A contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "will", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

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

- expected impact of future commitments and contingent liabilities.

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

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

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

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

- the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits;
- the operating performance of the Company's pipeline and energy assets;
- the availability and price of energy commodities;
- amount of capacity payments and revenues from the Company’s energy business;
- regulatory decisions and outcomes;
- outcomes with respect to legal proceedings, including arbitration;
- counterparty performance;
- changes in environmental and other laws and regulations;
- competitive factors in the pipeline and energy sectors;
- construction and completion of capital projects;
- labour, equipment and material costs;
- access to capital markets;
- interest and currency exchange rates;
- weather;
- technological developments; and
- economic conditions in North America.

Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC).

Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise stated, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this MD&A or otherwise stated, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning as prescribed by U.S. GAAP. They are, therefore, considered to be non-GAAP measures and are unlikely to be comparable to similar measures presented by other entities. Management of TransCanada 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 TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

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

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes, respectively, and are adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments. These non-GAAP measures are calculated on a consistent basis from period to period. The specific items for which such measures are adjusted in each applicable period may only be relevant in certain periods and are disclosed in the Reconciliation of Non-GAAP Measures table in this MD&A.

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

The Reconciliation of Non-GAAP Measures table in this MD&A presents a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares. Comparable Earnings per Common Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the year.

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

Reconciliation of Non-GAAP Measures

Three months ended March 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2012	Natural Gas Pipelines 2011	Oil Pipelines 2012	Oil Pipelines 2011	Energy 2012	Energy 2011	Corporate 2012	Corporate 2011	Total 2012	Total 2011
Comparable EBITDA	**725**	773	**173**	99	**244**	315	**(29)**	(24)	**1,113**	1,163
Depreciation and amortization	**(232)**	(228)	**(36)**	(23)	**(73)**	(67)	**(3)**	(3)	**(344)**	(321)
Comparable EBIT	**493**	545	**137**	76	**171**	248	**(32)**	(27)	**769**	842
Other Income Statement Items										
Comparable interest expense									**(242)**	(210)
Comparable interest income and other									**25**	28
Comparable income taxes									**(140)**	(187)
Net income attributable to non-controlling interests									**(35)**	(36)
Preferred share dividends									**(14)**	(14)
Comparable Earnings									**363**	423
Specific item (net of tax):										
Risk management activities[1]									**(11)**	(12)
Net Income Attributable to Common Shares									**352**	411

Three months ended March 31 *(unaudited) (millions of dollars)*	2012	2011
Comparable Interest Expense	**(242)**	(210)
Specific item:		
Risk management activities[1]	**-**	(1)
Interest Expense	**(242)**	(211)
Comparable Interest Income and Other	**25**	28
Specific item:		
Risk management activities[1]	**6**	2
Interest Income and Other	**31**	30
Comparable Income Taxes	**(140)**	(187)
Specific item:		
Income taxes attributable to risk management activities[1]	**11**	7
Income Taxes Expense	**(129)**	(180)
Comparable Earnings per Common Share	**$0.52**	$0.61
Specific item (net of tax):		
Risk management activities	**(0.02)**	(0.02)
Net Income per Share	**$0.50**	$0.59

(1)

Three months ended March 31 *(unaudited)(millions of dollars)*	2012	2011
Risk Management Activities Gains/(Losses):		
Canadian Power	**(2)**	-
U.S. Power	**(32)**	(13)
Natural Gas Storage	**6**	(7)
Interest rate	**-**	(1)
Foreign exchange	**6**	2
Income taxes attributable to risk management activities	**11**	7
Risk Management Activities	**(11)**	(12)

Consolidated Results of Operations

First Quarter Results

Comparable Earnings in first quarter 2012 were $363 million or $0.52 per share compared to $423 million or $0.61 per share for the same period in 2011. Comparable Earnings in first quarter 2012 excluded net unrealized after-tax losses of $11 million ($22 million pre-tax) (2011 – losses of $12 million after tax ($19 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings decreased $60 million or $0.09 per share in first quarter 2012 compared to the same period in 2011 and reflected the following:

- decreased Canadian Natural Gas Pipelines Comparable net income primarily due to lower earnings from the Canadian Mainline which exclude incentive earnings and reflect a lower investment base;
- decreased U.S. and International Natural Gas Pipelines EBIT which reflects lower revenue resulting from uncontracted capacity on Great Lakes and lower earnings from ANR, partially offset by incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011;
- increased Oil Pipelines Comparable EBIT as the Company commenced recording earnings from the Keystone Pipeline System in February 2011 and higher fixed tolls for the Wood River/Patoka section of the system;
- decreased Energy Comparable EBIT primarily due to a decrease in Equity Income from Bruce Power due to lower volumes resulting from increased planned outage days, lower realized power prices in U.S. Power and lower Natural Gas Storage revenue, partially offset by higher contributions from Western Power and Eastern Power;
- decreased Comparable Interest Income and Other due to lower realized gains in 2012 compared to 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income; and
- decreased Comparable Income Taxes primarily due to lower pre-tax earnings in 2012 compared to 2011.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is partially offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The average exchange rate to convert a U.S. dollar to a Canadian dollar for the three months ended March 31, 2012 was 1.00 (2011 – 0.99).

Summary of Significant U.S. Dollar-Denominated Amounts

Three months ended March 31 *(unaudited)(millions of U.S. dollars)*	**2012**	2011
U.S. Natural Gas Pipelines Comparable EBIT[1]	215	243
U.S. Oil Pipelines Comparable EBIT[1]	89	51
U.S. Power Comparable EBIT[1]	6	32
Interest on U.S. dollar-denominated long-term debt	(186)	(182)
Capitalized interest on U.S. capital expenditures	26	47
U.S. non-controlling interests and other	(51)	(51)
	99	140

(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 $493 million in first quarter 2012 compared to $545 million for the same period in 2011.

Natural Gas Pipelines Results

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Canadian Natural Gas Pipelines		
Canadian Mainline	**250**	265
Alberta System	**177**	185
Foothills	**31**	33
Other (TQM[1], Ventures LP)	**8**	8
Canadian Natural Gas Pipelines Comparable EBITDA[2]	**466**	491
Depreciation and amortization[3]	**(177)**	(178)
Canadian Natural Gas Pipelines Comparable EBIT[2]	**289**	313
U.S. and International Natural Gas Pipelines (in U.S. dollars)		
ANR	**97**	109
GTN[4]	**30**	45
Great Lakes[5]	**18**	30
TC PipeLines, LP[1][6][7]	**20**	23
Other U.S. Pipelines (Iroquois[1], Bison[8], Portland[7][9])	**34**	36
International (Tamazunchale, Guadalajara[10], TransGas[1], Gas Pacifico/INNERGY[1])	**28**	10
General, administrative and support costs[11]	**(2)**	(2)
Non-controlling interests[7]	**45**	43
U.S. and International Natural Gas Pipelines Comparable EBITDA[2]	**270**	294
Depreciation and amortization[3]	**(55)**	(51)
U.S. and International Natural Gas Pipelines Comparable EBIT[2]	**215**	243
Foreign exchange	**-**	(3)
U.S. and International Natural Gas Pipelines Comparable EBIT[2] (in Canadian dollars)	**215**	240
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[2]	**(11)**	(8)
Natural Gas Pipelines Comparable EBIT[2]	**493**	545
Summary:		
Natural Gas Pipelines Comparable EBITDA[2]	**725**	773
Depreciation and amortization[3]	**(232)**	(228)
Natural Gas Pipelines Comparable EBIT[2]	**493**	545

(1) Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect the Company's share of equity income from these investments.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(3) Does not include depreciation and amortization from equity investments.
(4) Results reflect TransCanada's direct ownership interest of 75 per cent effective May 2011 and 100 per cent prior to that date.
(5) Represents TransCanada's 53.6 per cent direct ownership interest.

(6) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. As a result, the TC PipeLines, LP results include TransCanada's decreased ownership in TC PipeLines, LP and TransCanada's effective ownership through TC PipeLines, LP of 8.3 per cent of each of GTN and Bison since May 2011.
(7) Non-Controlling Interests reflects Comparable EBITDA for the portions of TC PipeLines, LP and Portland not owned by TransCanada.
(8) Results reflect TransCanada's direct ownership of 75 per cent of Bison effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison went into service.
(9) Includes TransCanada's 61.7 per cent ownership interest.
(10) Includes Guadalajara's operations since June 2011.
(11) Represents General, Administrative and Support Costs associated with certain of TransCanada's pipelines.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

Three months ended March 31 *(millions of dollars)*	**2012**	2011
Canadian Mainline	**47**	62
Alberta System	**48**	48
Foothills	**5**	6

Canadian Natural Gas Pipelines

Canadian Mainline's net income of $47 million in first quarter 2012 decreased $15 million from $62 million in the same period in 2011. Canadian Mainline's first quarter 2011 net income included incentive earnings earned under an incentive arrangement included as part of the five-year tolls settlement which expired December 31, 2011. Absent a National Energy Board (NEB) decision with respect to 2012 tolls, Canadian Mainline's first quarter 2012 results reflect the last approved rate of return on common equity of 8.08 per cent on deemed common equity of 40 per cent and exclude incentive earnings. Canadian Mainline's first quarter 2012 results also reflect a lower investment base compared to first quarter 2011.

The Alberta System's net income of $48 million in first quarter 2012 was equal to that of 2011. The positive impact on 2012 net income from a higher average investment base was offset by lower incentive earnings.

Canadian Mainline's Comparable EBITDA for first quarter 2012 of $250 million decreased $15 million compared to the same period in 2011. The Alberta System's Comparable EBITDA was $177 million in first quarter 2012 compared to $185 million in the same period in 2011. EBITDA from the Canadian Mainline and the Alberta System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA in first quarter 2012 was US$97 million compared to US$109 million for the same period in 2011. The decrease was primarily due to higher operating, maintenance and administration (OM&A) costs, lower incidental commodity sales and lower transportation revenues.

GTN's Comparable EBITDA in first quarter 2012 was US$30 million compared to US$45 million for the same period in 2011. The decrease was primarily due to TransCanada's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011 as well as lower contracted transportation revenues.

Great Lakes' Comparable EBITDA in first quarter 2012 was US$18 million compared to US$30 million for the same period in 2011. The decrease was due to lower transportation revenues resulting from uncontracted capacity.

International Comparable EBITDA in first quarter 2012 was US$28 million compared to US$10 million for the same period in 2011 primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011.

Operating Statistics

Three months ended March 31 *(unaudited)*	Canadian Mainline[1] 2012	2011	Alberta System[2] 2012	2011	ANR[3] 2012	2011
Average investment base (millions of dollars)	**5,812**	6,404	**5,282**	4,966	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**430**	597	**998**	1,000	**482**	480
Average per day	**4.7**	6.6	**11.0**	11.1	**5.3**	5.3

(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, 2012 were 247 billion cubic feet (Bcf) (2011 – 376 Bcf); average per day was 2.7 Bcf (2011 – 4.2 Bcf).

(2) Field receipt volumes for the Alberta System for the three months ended March 31, 2012 were 948 Bcf (2011 – 843 Bcf); average per day was 10.4 Bcf (2011 – 9.4 Bcf).

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

Oil Pipelines

Oil Pipelines Comparable EBIT for first quarter 2012 was $137 million compared to $76 million for the same period in 2011.

Oil Pipelines Results

(unaudited)(millions of dollars)	**Three months ended March 31, 2012**	Two months ended March 31, 2011
Keystone Pipeline System	**174**	99
Oil Pipeline Business Development	**(1)**	-
Oil Pipelines Comparable EBITDA[1]	**173**	99
Depreciation and amortization	**(36)**	(23)
Oil Pipelines Comparable EBIT[1]	**137**	76
Comparable EBIT denominated as follows:		
Canadian dollars	**48**	26
U.S. dollars	**89**	51
Foreign exchange	**-**	(1)
Oil Pipelines Comparable EBIT[1]	**137**	76

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

Keystone Pipeline System

The Keystone Pipeline System's Comparable EBITDA in first quarter 2012 was $174 million compared to $99 million for the same period in 2011. The increase was primarily due to the impact of three months of earnings being recorded for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System compared to only two months in first quarter 2011, as well as the incremental impact of higher fixed tolls which came into effect in May 2011 on the Wood River/Patoka section of the system.

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

Depreciation and Amortization
Oil Pipelines depreciation and amortization increased $13 million in first quarter 2012 compared to the same period in 2011 reflecting three months of operations compared to two months in 2011 for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System.

Operating Statistics

(unaudited)	**Three months ended March 31, 2012**	Two months ended March 31, 2011
Delivery volumes (thousands of barrels)[1]		
Total	**48,764**	22,466
Average per day	**536**	381

(1) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $171 million in first quarter 2012 compared to $248 million for the same period in 2011.

Energy Results

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Canadian Power		
Western Power[(1)(2)]	**131**	119
Eastern Power[(1)(3)]	**93**	76
Bruce Power[(1)]	**(13)**	43
General, administrative and support costs	**(11)**	(8)
Canadian Power Comparable EBITDA[(4)]	**200**	230
Depreciation and amortization[(5)]	**(40)**	(34)
Canadian Power Comparable EBIT[(4)]	**160**	196
U.S. Power (in U.S. dollars)		
Northeast Power	**46**	71
General, administrative and support costs	**(10)**	(9)
U.S. Power Comparable EBITDA[(4)]	**36**	62
Depreciation and amortization	**(30)**	(30)
U.S. Power Comparable EBIT[(4)]	**6**	32
Foreign exchange	**-**	-
U.S. Power Comparable EBIT[(4)] (in Canadian dollars)	**6**	32
Natural Gas Storage		
Alberta Storage[(1)]	**15**	30
General, administrative and support costs	**(2)**	(2)
Natural Gas Storage Comparable EBITDA[(4)]	**13**	28
Depreciation and amortization[(5)]	**(3)**	(3)
Natural Gas Storage Comparable EBIT[(4)]	**10**	25
Energy Business Development Comparable EBITDA and EBIT[(1)(4)]	**(5)**	(5)
Energy Comparable EBIT[(1)(4)]	**171**	248
Summary:		
Energy Comparable EBITDA[(4)]	**244**	315
Depreciation and amortization[(5)]	**(73)**	(67)
Energy Comparable EBIT[(4)]	**171**	248

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

Canadian Power

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

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Revenue		
Western power[(2)]	**224**	221
Eastern power[(3)]	**103**	96
Other[(4)]	**25**	23
	352	340
Income from Equity Investments[(5)]	**23**	27
Commodity Purchases Resold		
Western power	**(94)**	(104)
Other[(6)]	**(2)**	(5)
	(96)	(109)
Plant operating costs and other	**(55)**	(63)
General, administrative and support costs	**(11)**	(8)
Comparable EBITDA[(1)]	**213**	187
Depreciation and amortization	**(40)**	(34)
Comparable EBIT[(1)]	**173**	153

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge effective May 2011. Includes the net realized gains and losses from derivatives used to purchase and sell power.
(3) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011.
(4) Includes sales of excess natural gas purchased for generation and thermal carbon black. Includes the net realized gains and losses from derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets.
(5) Results reflect equity income from TransCanada's 50 per cent ownership interest in each of ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.
(6) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics[1]

Three months ended March 31 *(unaudited)*	**2012**	2011
Volumes (GWh)		
Generation		
Western Power[2]	**671**	681
Eastern Power[3]	**1,143**	1,078
Purchased		
Sundance A and B and Sheerness PPAs[4]	**2,039**	2,105
Other purchases	**45**	88
	3,898	3,952
Contracted		
Western Power[2]	**2,295**	2,155
Eastern Power[3]	**1,143**	1,078
Spot		
Western Power	**460**	719
	3,898	3,952
Plant Availability[5]		
Western Power[2][6]	**99%**	98%
Eastern Power[3][7]	**93%**	99%

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

Western Power's Comparable EBITDA of $131 million and Power Revenues of $224 million in first quarter 2012 increased $12 million and $3 million, respectively, compared to the same period in 2011, primarily due to incremental earnings from Coolidge, which was placed in service in May 2011, and higher realized power prices, partially offset by a decrease in Sundance A power purchase arrangement (PPA) earnings.

Western Power's Comparable EBITDA in first quarter 2012 included $30 million (2011 - $39 million) of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 are interruptions of supply in accordance with the terms of the PPA. The decrease of $9 million in Sundance A earnings in first quarter 2012 compared to first quarter 2011 is a result of lower Alberta spot power prices in 2012. Average spot market power prices in Alberta decreased 28 per cent to $60 per megawatt hour (MWh) in first quarter 2012 compared to $83 per MWh in first quarter 2011 when unseasonably cold weather combined with unplanned plant outages caused an increase in demand and reduction in market supply. Despite the decrease in spot prices, Western Power earned a higher realized price compared to the prior period as a result of hedging activities. Refer to the Recent Developments section in this MD&A for further discussion regarding the Sundance A outage.

Eastern Power's Comparable EBITDA of $93 million and Power Revenues of $103 million in first quarter 2012 increased $17 million and $7 million, respectively, compared to the same period in 2011. The increases were primarily due to higher Bécancour contractual earnings and incremental earnings from Montagne-Sèche and phase one of Gros-Morne, which was placed in service in November 2011.

Plant Operating Costs and Other, which includes fuel gas consumed in power generation, of $55 million in first quarter 2012, decreased $8 million compared to the same period in 2011, primarily due to decreased natural gas fuel prices in first quarter 2012 compared to the same period in 2011.

Depreciation and amortization increased $6 million in first quarter 2012 compared to the same period in 2011 primarily due to incremental depreciation from Coolidge, Montagne-Sèche and phase one of Gros-Morne.

Approximately 83 per cent of Western Power sales volumes were sold under contract in first quarter 2012, compared to 75 per cent in first quarter 2011. To reduce its exposure to spot market prices in Alberta, as at March 31, 2012, Western Power had entered into fixed-price power sales contracts to sell approximately 6,000 gigawatt hours (GWh) for the remainder of 2012 and 6,300 GWh for 2013.

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

Bruce Power Results

(TransCanada's share)
Three months ended March 31

(unaudited)(millions of dollars unless otherwise indicated)	**2012**	2011
Income from Equity Investments[(1)]		
Bruce A	**(33)**	18
Bruce B	**20**	25
	(13)	43
Comprised of:		
Revenues	**162**	213
Operating expenses	**(135)**	(136)
Depreciation and other	**(40)**	(34)
	(13)	43
Bruce Power – Other Information		
Plant availability[(2)]		
Bruce A	**48%**	100%
Bruce B	**86%**	91%
Combined Bruce Power	**62%**	94%
Planned outage days		
Bruce A	**91**	-
Bruce B	**46**	21
Unplanned outage days		
Bruce A	**-**	4
Bruce B	**4**	8
Sales volumes (GWh)[(1)]		
Bruce A	**747**	1,500
Bruce B	**1,909**	2,032
	2,656	3,532
Realized sales price per MWh		
Bruce A	**$66**	$65
Bruce B[(3)]	**$54**	$53
Combined Bruce Power	**$57**	$57

(1) Represents TransCanada's 48.8 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.
(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.
(3) Includes revenue received under the floor price mechanism and from contract settlements as well as volumes and revenues associated with deemed generation.

TransCanada's Equity Income from Bruce A decreased $51 million in first quarter 2012 to a loss of $33 million compared to income of $18 million in first quarter 2011 primarily due to lower volumes resulting from the West Shift Plus planned outage on Unit 3 which took place throughout the quarter and is expected to be completed in second quarter 2012.

TransCanada's Equity Income from Bruce B decreased $5 million in first quarter 2012 to $20 million compared to $25 million in first quarter 2011 primarily due to lower volumes resulting from higher planned outage days.

Under a contract with the Ontario Power Authority (OPA), all output from Bruce A in first quarter 2012 was sold at a fixed price of $66.33 per MWh (before recovery of fuel costs from the OPA) compared to $64.71 per MWh in first quarter 2011. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $50.18 per MWh in first quarter 2012 compared to $48.96 per MWh in first quarter 2011. Effective April 1, 2012, the fixed price for output from Bruce A increased to $68.23 per MWh and the Bruce B floor price increased to $51.62 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 2012, TransCanada currently expects spot prices to be less than the floor price for the year, therefore no amounts recorded in revenues in first quarter 2012 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 increased by $1 per MWh to $54 per MWh in first quarter 2012 compared to the same period in 2011 and reflected revenues recognized from the floor price mechanism, contract sales and deemed generation.

The overall plant availability percentage in 2012 is expected to be in the low 70s for Bruce A Units 3 and 4. The Bruce A West Shift Plus outage, which commenced in November 2011, is expected to be completed in second quarter 2012. Additional planned maintenance on one of the units at Bruce A is scheduled for the summer of 2012. Bruce B's overall plant availability percentage is expected to be in the mid 90s for the four units in 2012.

U.S. Power

U.S. Power Comparable EBIT(1)

Three months ended March 31 *(unaudited)(millions of U.S. dollars)*	**2012**	2011
Revenues		
Power(2)	**161**	255
Capacity	**40**	39
Other(3)	**19**	30
	220	324
Commodity purchases resold	**(83)**	(131)
Plant operating costs and other(3)	**(91)**	(122)
General, administrative and support costs	**(10)**	(9)
Comparable EBITDA(1)	**36**	62
Depreciation and amortization	**(30)**	(30)
Comparable EBIT(1)	**6**	32

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

U.S. Power Operating Statistics

Three months ended March 31 *(unaudited)*	**2012**	2011
Physical Sales Volumes (GWh)		
Supply		
Generation	**1,154**	1,291
Purchased	**1,954**	1,939
	3,108	3,230
Plant Availability(1)	**80%**	82%

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

U.S Power's Comparable EBITDA of US$36 million and Power Revenues of US$161 million decreased US$26 million and US$94 million, respectively, compared to the same period in 2011. The reduction was primarily due to lower realized power prices which were negatively impacted by lower natural gas prices.

Capacity Revenue of US$40 million in first quarter 2012 increased US$1 million compared to the same period in 2011. Capacity Revenues in first quarter 2012 were positively impacted by higher capacity prices in New York while New England capacity prices decreased slightly compared to 2011.

Commodity Purchases Resold of US$83 million decreased US$48 million compared to the same period in 2011 primarily due to lower realized prices on power purchased for resale under power sales commitments to wholesale, commercial and industrial customers.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of US$91 million decreased US$31 million primarily due to lower natural gas fuel prices.

As at March 31, 2012, approximately 3,000 GWh or 35 per cent and 2,500 GWh or 30 per cent of U.S. Power's planned generation is contracted for the remainder 2012 and fiscal 2013, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA in first quarter 2012 declined to $13 million compared to $28 million for the same period in 2011 primarily due to lower realized natural gas price spreads.

Other Income Statement Items

Comparable Interest Expense[1]

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Interest on long-term debt[2]		
Canadian dollar-denominated	**128**	122
U.S. dollar-denominated	**186**	182
Foreign exchange	**-**	(3)
	314	301
Other interest and amortization	**2**	6
Capitalized interest	**(74)**	(97)
Comparable Interest Expense[1]	**242**	210

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

Comparable Interest Expense in first quarter 2012 increased $32 million to $242 million compared to $210 million in first quarter 2011. The increase was primarily due to lower capitalized interest for Keystone and Coolidge as a result of placing these assets in service, incremental interest expense on debt issues of US$500 million in March 2012, $750 million in November 2011 and US$350 million in July 2011. These increases were partially offset by the impact of Canadian and U.S. dollar-denominated debt maturities in 2012 and 2011.

Comparable Interest Income and Other for first quarter 2012 decreased $3 million to $25 million compared to $28 million in first quarter 2011, primarily due to lower realized gains in 2012 compared to 2011 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 $140 million in first quarter 2012 compared to $187 million for the same period in 2011. The decrease was primarily due to lower pre-tax earnings in 2012 compared to 2011.

Liquidity and Capital Resources

TransCanada believes that its financial position remains sound as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TransCanada's liquidity is underpinned by predictable cash flow from operations, available cash balances and unutilized committed revolving bank lines of US$1.0 billion, US$1.0 billion, US$300 million and $2.0 billion, maturing in October 2012, November 2012, February 2013 and October 2016, respectively. These facilities also support the Company's three commercial paper programs. In addition, at March 31, 2012, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada operated affiliates was $84 million with maturity dates in 2016. As at March 31, 2012, TransCanada had remaining capacity of $2.0 billion, $1.25 billion and US$3.5 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

Operating Activities

Funds Generated from Operations[1]

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Cash Flows		
Funds generated from operations[1]	**841**	815
(Increase)/decrease in operating working capital	**(169)**	19
Net cash provided by operations	**672**	834

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

Net Cash Provided by Operations decreased $162 million in the first quarter of 2012, compared to the same period in 2011, largely as a result of changes in operating working capital partially offset by increased Funds Generated from Operations. Funds Generated from Operations for the first quarter 2012 were $841 million compared to $815 million for the same period in 2011.

As at March 31, 2012, TransCanada's current assets were $2.7 billion and current liabilities were $4.7 billion resulting in a working capital deficiency of $2.0 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations as well as its ongoing access to capital markets.

Investing Activities

In first quarter 2012, capital expenditures totalled $464 million (2011– $567 million), primarily related to the expansion of the Keystone Pipeline System and expansion of the Alberta System. Equity investments of $216 million (2011 - $151 million) primarily related to the Company's investment in the refurbishment and restart of Bruce Power Units 1 and 2.

Financing Activities

In March 2012, TransCanada PipeLines Limited (TCPL) issued US$500 million of Senior Notes maturing on March 2, 2015 and bearing interest at an annual rate of 0.875 per cent. These notes were issued under the US$4.0 billion debt shelf prospectus filed in November 2011. The net proceeds of this offering were used for general corporate purposes and to reduce short-term indebtedness.

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

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

Dividends

On April 26, 2012, TransCanada's Board of Directors declared a quarterly dividend of $0.44 per share for the quarter ending June 30, 2012 on the Company's outstanding common shares. The dividend is payable on July 31, 2012 to shareholders of record at the close of business on June 29, 2012. In addition, quarterly dividends of $0.2875 and $0.25 per Series 1 and Series 3 preferred share, respectively, were declared for the quarter ending June 30, 2012. The dividends are payable on June 29, 2012 to shareholders of record at the close of business on May 31, 2012. Furthermore, a quarterly dividend of $0.275 per Series 5 preferred share was declared for the period ending July 30, 2012, payable on July 30, 2012 to shareholders of record at the close of business on June 30, 2012.

Contractual Obligations

There have been no material changes to TransCanada's contractual obligations from December 31, 2011 to March 31, 2012, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TransCanada's 2011 Annual Report.

Significant Accounting Policies and Critical Accounting Estimates

The condensed consolidated financial statements of TransCanada have been prepared by management in accordance with U.S. GAAP. Comparative figures, which were previously presented in accordance with CGAAP, have been adjusted as necessary to be compliant with the Company's policies under U.S. GAAP. The amounts adjusted for U.S. GAAP in these condensed consolidated financial statements for the three months ended March 31, 2011 are the same as those that have been previously reported in the Company's March 31, 2011 Reconciliation to U.S. GAAP. The amounts adjusted for U.S. GAAP at December 31, 2011 are the same as those reported in Note 25 of TransCanada's 2011 audited Consolidated Financial Statements included in TransCanada's 2011 Annual Report. The significant accounting policies and critical accounting estimates applied are consistent with those outlined in TransCanada's 2011 Annual Report, except as described below, which outlines the Company's significant accounting policies that have changed upon adoption of U.S. GAAP.

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

Changes in Accounting Policies

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

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

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

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

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

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

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

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

Long-Term Debt Transaction Costs
Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company records long-term debt transaction costs as deferred assets and amortizes these costs using the effective interest method for all costs except those related to the

Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

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

Changes in Accounting Policies for 2012

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

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

Future Accounting Changes

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

Financial Instruments and Risk Management

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

Counterparty Credit and Liquidity Risk
TransCanada'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, 2012, there were no significant amounts past due or impaired.

At March 31, 2012, the Company had a credit risk concentration of $267 million due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At March 31, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10.4 billion (US$10.4 billion) and a fair value of $12.9 billion (US$12.9 billion). At March 31, 2012, $97 million (December 31, 2011 - $79 million) was included in Other Current Assets, $83 million (December 31, 2011 - $66 million) was included in Intangibles and Other Assets, $4 million (December 31, 2011 - $15 million) was included in Accounts Payable and $30 million (December 31, 2011 - $41 million) was included in Deferred Amounts for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

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

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**March 31, 2012** **Fair Value(1)**	**March 31, 2012** **Notional or Principal Amount**	December 31, 2011 Fair Value(1)	December 31, 2011 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2019)(2)	**128**	**US 4,150**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2012)	**18**	**US 1,165**	(4)	US 725
	146	**US 5,315**	89	US 4,575

(1) Fair values equal carrying values.

(2) Consolidated Net Income in first quarter 2012 included net realized gains of $7 million (2011 – gains of $5 million) related to the interest component of cross-currency swap settlements.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**March 31, 2012** Carrying Amount[(1)]	Fair Value[(2)]	December 31, 2011 Carrying Amount[(1)]	Fair Value[(2)]
Financial Assets				
Cash and cash equivalents	**196**	**196**	654	654
Accounts receivable and other[(3)]	**1,326**	**1,369**	1,359	1,403
Available-for-sale assets[(3)]	**34**	**34**	23	23
	1,556	**1,599**	2,036	2,080
Financial Liabilities[(4)]				
Notes payable	**1,787**	**1,787**	1,863	1,863
Accounts payable and deferred amounts[(5)]	**1,016**	**1,016**	1,329	1,329
Accrued interest	**360**	**360**	365	365
Long-term debt	**18,397**	**23,313**	18,659	23,757
Junior subordinated notes	**998**	**1,031**	1,016	1,027
	22,558	**27,507**	23,232	28,341

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

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

(3) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial assets of $1,068 million (December 31, 2011 – $1,094 million) in Accounts Receivable, $33 million (December 31, 2011 – $41 million) in Other Current Assets and $259 million (December 31, 2011 - $247 million) in Intangibles and Other Assets.

(4) Consolidated Net Income in first quarter 2012 included losses of $15 million (2011 – losses of $9 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2011 – US$350 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(5) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial liabilities of $886 million (December 31, 2011 – $1,192 million) in Accounts Payable and $130 million (December 31, 2011 - $137 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

March 31, 2012 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$314**	**$189**	**$9**	**$19**
Liabilities	**$(329)**	**$(232)**	**$(13)**	**$(19)**
Notional Values				
Volumes[3]				
Purchases	**31,088**	**104**	**-**	**-**
Sales	**29,851**	**76**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**684**
U.S. dollars	**-**	**-**	**US 1,476**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2012[4]	**$(7)**	**$(14)**	**$6**	**$-**
Net realized gains/(losses) in the three months ended March 31, 2012[4]	**$15**	**$(10)**	**$9**	**$-**
Maturity dates	**2012-2016**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$40**	**$-**	**$-**	**$15**
Liabilities	**$(321)**	**$(23)**	**$(39)**	**$-**
Notional Values				
Volumes[3]				
Purchases	**21,455**	**6**	**-**	**-**
Sales	**8,704**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 42**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized (losses)/gains in the three months ended March 31, 2012[4]	**$(32)**	**$(6)**	**$-**	**$1**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2013-2015**

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $15 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three months ended March 31, 2012 were $2 million and were included in Interest Expense. In first quarter 2012, 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, 2012, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

2011

(unaudited) *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2][3]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values[3]				
Volumes[4]				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US 1,269	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized (losses)/gains in the three months ended March 31, 2011[5]	$(1)	$(16)	$2	$(1)
Net realized (losses)/gains in the three months ended March 31, 2011[5]	$(1)	$(26)	$21	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships[6][7]				
Fair Values[2][3]				
Assets	$16	$3	$-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values[3]				
Volumes[4]				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US 73	US 600
Cross-currency	-	-	136/US 100	-
Net realized losses in the three months ended March 31, 2011[5]	$(43)	$(3)	$-	$(1)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

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

(2) Fair values equal carrying values.

(3) As at December 31, 2011.

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

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

(6) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million at December 31, 2011. Net realized gains on fair value hedges for the three 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.

(7) For the three months ended March 31, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**March 31 2012**	December 31 2011
Current		
Other current assets	**503**	361
Accounts payable	**(607)**	(485)
Long term		
Intangibles and other assets	**263**	202
Deferred amounts	**(403)**	(349)

Derivatives in Cash Flow Hedging Relationships

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

Three months ended March 31 *(unaudited)* *(millions of dollars, pre-tax)*	Cash Flow Hedges Power **2012**	 2011	 Natural Gas **2012**	 2011	 Foreign Exchange **2012**	 2011	 Interest **2012**	 2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**(66)**	(55)	**(10)**	(11)	**(3)**	(6)	**-**	-
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**47**	34	**13**	28	**-**	-	**6**	9
Losses on derivative instruments recognized in earnings (ineffective portion)	**(6)**	(2)	**(2)**	(1)	**-**	-	**-**	-

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at March 31, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2011 - $86 million), for which the Company had provided collateral of $53 million (2011 - $3 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2012, the Company would have been required to provide additional collateral of $57 million (2011 - $83 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the fair value hierarchy.

In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

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

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II. There were no transfers between Level II and Level III in first quarter 2012 and 2011.

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

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

(unaudited) (millions of dollars, pre-tax)	Quoted Prices in Active Markets (Level I) Mar 31 2012	Dec 31 2011	Significant Other Observable Inputs (Level II) Mar 31 2012	Dec 31 2011	Significant Unobservable Inputs (Level III) Mar 31 2012	Dec 31 2011	Total Mar 31 2012	Dec 31 2011
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**34**	36	**-**	-	**34**	36
Foreign exchange contracts	**-**	-	**187**	141	**-**	-	**187**	141
Power commodity contracts	**-**	-	**337**	201	**-**	-	**337**	201
Gas commodity contracts	**136**	124	**50**	55	**-**	-	**186**	179
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(19)**	(23)	**-**	-	**(19)**	(23)
Foreign exchange contracts	**-**	-	**(84)**	(102)	**-**	-	**(84)**	(102)
Power commodity contracts	**-**	-	**(621)**	(454)	**(11)**	(15)	**(632)**	(469)
Gas commodity contacts	**(228)**	(208)	**(25)**	(26)	**-**	-	**(253)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**34**	23	**-**	-	**-**	-	**34**	23
	(58)	(61)	**(141)**	(172)	**(11)**	(15)	**(210)**	(248)

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

Three months ended March 31 *(unaudited) (millions of dollars, pre-tax)*	Derivatives[(1)(2)] **2012**	2011
Balance at January 1	**(15)**	(8)
New contracts	**-**	1
Total gains or losses included in OCI	**4**	(6)
Balance at March 31	**(11)**	(13)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) At March 31, 2012, there were no unrealized gains or losses included in Net Income attributable to derivatives that were still held at the reporting date (2011 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at March 31, 2012.

Other Risks

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

Controls and Procedures

As of March 31, 2012, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of TransCanada'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 TransCanada's disclosure controls and procedures were effective at a reasonable assurance level as at March 31, 2012.

During the quarter ended March 31, 2012, there have been no changes in TransCanada's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, TransCanada's internal control over financial reporting.

Outlook

Since the disclosure in TransCanada's 2011 Annual Report, the Company's overall earnings outlook for 2012 will be moderately impacted by the delay in the return to service of Bruce Power's Unit 2 to second quarter 2012. In addition, reduced demand for natural gas and electricity due to unseasonably warm weather, combined with continued strong U.S. natural gas production, has resulted in historically high natural gas storage levels and low natural gas prices, which could have a negative impact on revenues in U.S. Pipelines, and power prices in Canadian and U.S. Power. The Company's earnings outlook could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York and resolution of the Sundance A PPA dispute, as discussed in the Recent Developments section of this MD&A. For further information on outlook, refer to the MD&A in TransCanada's 2011 Annual Report.

Recent Developments

Natural Gas Pipelines

Canadian Mainline
2012-2013 Tolls Application
Further to the comprehensive tolls application filed with the NEB in 2011 to change the business structure and the terms and conditions of service for the Canadian Mainline, TransCanada is working with the NEB and other stakeholders by exchanging information in advance of the oral hearing scheduled to commence in Calgary in June 2012. The hearing is scheduled to conclude in September 2012 with a decision expected in late 2012 or early 2013.

Marcellus Facilities Expansion
Further to the Application that was re-filed in November 2011 to construct new pipeline infrastructure to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin, TransCanada filed responses to NEB information requests in January 2012. In a February 2012 letter, the NEB indicated it would not convene a hearing for the Application but would continue to assess the Application as a non-hearing application. Assuming the project receives approval to proceed, construction is scheduled to begin in early July 2012, with planned completion in November 2012. The capital cost of the Marcellus Facilities Expansion is expected to be approximately $130 million.

Mainline New Capacity Open Season
A New Capacity Open Season (NCOS) on the Canadian Mainline, that remains open until May 2012, was announced to capture additional Marcellus supply at the Niagara or Chippawa border points, as well as from other receipt points on the integrated system to all delivery points downstream of Parkway such as Iroquois/Waddington, GMI EDA and East Hereford. The NCOS is in response to shippers that have expressed interests for new firm transportation capacity. New service start dates of November 2013 and November 2014 are proposed, subject to all necessary regulatory approvals.

Alberta System
Expansion Projects
During the first four months of 2012, TransCanada has substantially completed 10 separate pipeline projects for the Alberta System at a cost of approximately $600 million.

ATCO Pipelines Commercial Integration
Commercial integration of the Alberta System and ATCO Pipelines (ATCO) commenced in October 2011. TransCanada continues to work with ATCO to gather information for the final stage of the integration which is to swap assets of equal value. As a result, the expected timing of the asset swap application, which was to be completed in first quarter 2012, has been delayed until mid-2012.

Tamazunchale Pipeline Extension Bid
TransCanada was awarded the approximately $500 million Tamazunchale Pipeline Extension Project in Mexico and executed a contract with the Comisión Federal de Electricidad in February 2012. Engineering, Procurement and Construction contracts have been executed and construction related activities have begun. The pipeline is expected to be in service in first quarter 2014.

Alaska Pipeline Project
The Alaska North Slope producers (ExxonMobil, ConocoPhillips and BP), along with TransCanada through its participation in the Alaska Pipeline Project, announced in March 2012 that the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources via a liquefied natural gas (LNG) option. TransCanada has applied to the State of Alaska for a project plan amendment under the Alaska Gasline Inducement Act (AGIA) license to curtail work on the Alberta pipeline option in a way that preserves project assets and defers the Federal Energy Regulatory Commission (FERC) filing date until October 2014 (rather than October 2012 under the current AGIA provisions), while the preliminary assessment of the LNG alternative is underway.

Mackenzie Gas Project
The proponents of the Mackenzie Gas Project have been unable to finalize commercial terms which would allow the project to advance under current market conditions. As a result, project activities have been curtailed. TransCanada's future funding obligations for the Aboriginal Pipeline Group during such curtailment are expected to be nominal.

Oil Pipelines

Gulf Coast Project
The Company announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Project has its own independent value to the marketplace and will be constructed as the stand-alone Gulf Coast Project, not part of the Presidential Permit process. The approximate cost of the 36-inch line is US$2.3 billion and, subject to regulatory approvals, TransCanada expects the Gulf Coast Project to be in service in mid to late 2013. As of March 31, 2012, US$0.8 billion has been invested in the program. Included in the US$2.3 billion cost is US$300 million for the 76 kilometre (47-mile) Houston Lateral pipeline that will transport oil to Houston refineries.

Keystone XL Pipeline
Also in February, TransCanada sent a letter to the U.S. Department of State (DOS) informing the Department the Company plans to re-file a Presidential Permit application (cross border permit) in the near future for the Keystone XL Project from the U.S./Canada border in Montana to Steele City, Nebraska. TransCanada noted

it would supplement that application with an alternative route in Nebraska as soon as that route is selected. The application will include the already reviewed route in Montana and South Dakota. The over three year environmental review for Keystone XL completed last summer was the most comprehensive process ever for a cross border pipeline. Based on that work, TransCanada expects its cross border permit should be processed expeditiously and a decision made once a new route in Nebraska is determined.

Earlier this month, legislation was passed in Nebraska and signed into law by the Governor that enabled TransCanada to re-engage with the State's Department of Environmental Quality (DEQ), allowing the Company to continue to work collaboratively in determining an alternative route for Keystone XL that avoids the Sandhills. Alternative routing corridors and a preferred corridor were submitted to the DEQ April 18, 2012. The Department will now oversee the public comment and review process as TransCanada develops a specific alternate route.

The capital cost of Keystone XL is estimated to be US$5.3 billion, with US$1.5 billion having been invested as of March 31, 2012. The remainder will be spent between now and the in-service date of the expansion, which is expected by late 2014 or early 2015.

Keystone Hardisty Terminal

In March 2012, TransCanada launched and concluded an open season to obtain binding commitments for the Keystone Hardisty Terminal. The two million barrel project located at Hardisty, Alberta will provide new infrastructure for Western Canadian producers and access to the Keystone Pipeline System. TransCanada is currently reviewing the results of the open season. The Keystone Hardisty Terminal is expected to be operational by late 2014 or early 2015.

Energy

Bruce Power

In March 2012, Bruce Power received authorization from the Canadian Nuclear Safety Commission to restart Unit 2, effectively ending the construction and commissioning phases of the project. The reactor is presently producing steam and final safety checks are being conducted. Commercial operations for Unit 2 are expected to commence in second quarter 2012. Commissioning work on Unit 1 is currently underway and Bruce Power expects commercial operations for Unit 1 to commence in mid-third quarter 2012. TransCanada's share of the total net capital cost is expected to be approximately $2.4 billion.

In accordance with the terms of the Bruce Power Refurbishment Implementation Agreement (BPRIA), Bruce A receives Contingent Support Payments (CSP) from the OPA equal to the difference between the fixed prices under the BPRIA and spot market prices through July 1, 2012 after which all of the output from Bruce A will be subject to spot market prices until both Units 1 and 2 have achieved commercial operations.

Sundance A

The arbitration hearing to address the Sundance A force majeure and economic destruction claims dispute commenced April 9, 2012. The hearing is expected to conclude in May 2012 and TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $30 million of EBITDA for the three months ended March 31, 2012 and $188 million since the interruption began. The outcome of any arbitration process is not certain. However, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at March 31, 2012 of $74 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Ravenswood

Spot market capacity prices in the New York Zone J market have increased in first quarter 2012 compared to the prior year primarily due to the combination of higher demand curve rates which were reset in late third quarter 2011 and rule changes implemented by the New York Independent System Operator's (NYISO) which changed the way certain capacity is measured in this market.

In 2011, TransCanada and other parties filed formal complaints with FERC regarding application of pricing rules by the NYISO. These complaints are still pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown.

Share Information

At April 24, 2012, TransCanada had 704 million issued and outstanding common shares, and had 22 million Series 1, 14 million Series 3 and 14 million Series 5 issued and outstanding first preferred shares that are convertible to 22 million Series 2, 14 million Series 4 and 14 million Series 6 preferred shares, respectively. In addition, there were nine million outstanding options to purchase common shares, of which five million were exercisable as at April 24, 2012.

Selected Quarterly Consolidated Financial Data[1]

(unaudited)	2012	2011				2010		
(millions of dollars, except per share amounts)	**First**	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**1,911**	1,967	1,987	1,797	1,868	1,675	1,776	1,616
Net income attributable to controlling interests	**366**	390	399	367	425	277	393	290
Share Statistics								
Net Income per common share								
Basic	**$0.50**	$0.53	$0.55	$0.50	$0.59	$0.38	$0.55	$0.41
Diluted	**$0.50**	$0.53	$0.55	$0.50	$0.59	$0.37	$0.55	$0.41
Dividend declared per common share	**$0.44**	$0.42	$0.42	$0.42	$0.42	$0.40	$0.40	$0.40

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

Factors Affecting Quarterly Financial Information

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

In Oil Pipelines, which consists of the Company's investment in the Keystone Pipeline System, earnings are primarily generated by contractual arrangements for committed capacity that are not dependent on actual throughput. Quarter-over-quarter revenues, EBIT and net income during any particular fiscal year remain relatively stable with fluctuations resulting from planned and unplanned outages, and changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, and developments outside of the normal course of operations.

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

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

- First Quarter 2012, EBIT included net realized losses of $22 million pre-tax ($11 million after tax) from certain risk management activities.

- Fourth Quarter 2011, EBIT excluded net unrealized gains of $9 million pre-tax ($11 million after tax) resulting from certain risk management activities.

- Third Quarter 2011, Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of $43 million pre-tax ($30 million after tax) resulting from certain risk management activities.

- Second Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Guadalajara, which was placed in service in June 2011. Energy's EBIT included incremental earnings from Coolidge, which was placed in service in May 2011. EBIT included net unrealized losses of $3 million pre-tax ($2 million after tax) resulting from certain risk management activities.

- First Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System in February 2011. EBIT included net unrealized losses of $19 million pre-tax ($12 million after tax) resulting from certain risk management activities.

- Fourth Quarter 2010, Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after tax) valuation provision for advances to the Aboriginal Pipeline Group for the Mackenzie Gas Project. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of $46 million pre-tax ($29 million after tax) resulting from certain risk management activities.

- 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 loss of $1million pre-tax ($1 million after tax) resulting from certain risk management activities.

- Second Quarter 2010, Energy's EBIT included net unrealized gains of $16 million pre-tax ($11 million after tax) resulting from 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.

Condensed Consolidated Statement of Income

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars except per share amounts)*	2012	2011 Adjusted (Note 1)
Revenues		
Natural Gas Pipelines	**1,085**	1,062
Oil Pipelines	**259**	135
Energy	**567**	671
	1,911	1,868
Income from Equity Investments	**60**	121
Operating and Other Expenses		
Plant operating costs and other	**707**	609
Commodity purchases resold	**179**	238
Depreciation and amortization	**344**	320
	1,230	1,167
Financial Charges/(Income)		
Interest expense	**242**	211
Interest income and other	**(31)**	(30)
	211	181
Income before Income Taxes	**530**	641
Income Taxes Expense		
Current	**56**	106
Deferred	**73**	74
	129	180
Net Income	**401**	461
Net Income Attributable to Non-Controlling Interests	**35**	36
Net Income Attributable to Controlling Interests	**366**	425
Preferred Share Dividends	**14**	14
Net Income Attributable to Common Shares	**352**	411
Net Income per Common Share		
Basic and Diluted	**$0.50**	$0.59
Dividends Declared per Common Share	**$0.44**	$0.42
Weighted-average Number of Common Shares (millions)		
Basic	**704**	698
Diluted	**705**	699

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Comprehensive Income

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	2012	2011 Adjusted (Note 1)
Net Income	**401**	461
Other Comprehensive (Loss)/Income, Net of Income Taxes		
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(107)**	(116)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	**38**	49
Change in fair value of derivative instruments designated as cash flow hedges[3]	**(45)**	(53)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	**45**	48
Reclassification to Net Income of actuarial (gains)/losses and prior service costs on pension and other post-retirement benefit plans[5]	**10**	2
Other Comprehensive Loss of Equity Investments[6]	**5**	2
Other Comprehensive Loss	**(54)**	(68)
Comprehensive Income	**347**	393
Comprehensive Income Attributable to Non-Controlling Interests	**18**	21
Comprehensive Income Attributable to Controlling Interests	**329**	372
Preferred Share Dividends	**14**	14
Comprehensive Income Attributable to Common Shares	**315**	358

(1) Net of income tax expense of $22 million for the three months ended March 31, 2012 (2011 – expense of $29 million).
(2) Net of income tax expense of $11 million for the three months ended March 31, 2012 (2011 – expense of $19 million).
(3) Net of income tax recovery of $34 million for the three months ended March 31, 2012 (2011 – recovery of $19 million).
(4) Net of income tax expense of $21 million for the three months ended March 31, 2012 (2011 – expense of $25 million).
(5) Net of income tax recovery of $4 million for the three months ended March 31, 2012 (2011 – expense of $1 million).
(6) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, gains and losses on derivative instruments designated as cash flow hedges, offset by change in gains and losses on derivative instruments designated as cash flow hedges, net of income tax expense of $1 million for the three months ended March 31, 2012 (2011 – expense of $1 million).

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Cash Flows

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	**2012**	2011 Adjusted (Note 1)
Cash Generated from Operations		
Net income	**401**	461
Depreciation and amortization	**344**	320
Deferred income taxes	**73**	74
Income from equity investments	**(60)**	(121)
Distributions received from equity investments	**53**	65
Employee future benefits expense in excess of/(less than) funding	**7**	(3)
Other	**23**	19
(Increase)/decrease in operating working capital	**(169)**	19
Net cash provided by operations	**672**	834
Investing Activities		
Capital expenditures	**(464)**	(567)
Equity investments	**(216)**	(151)
Deferred amounts and other	**(7)**	65
Net cash used in investing activities	**(687)**	(653)
Financing Activities		
Dividends on common and preferred shares	**(310)**	(200)
Distributions paid to non-controlling interests	**(33)**	(27)
Notes payable (repaid)/issued, net	**(46)**	134
Long-term debt issued, net of issue costs	**492**	-
Reduction of long-term debt	**(548)**	(321)
Common shares issued	**14**	21
Net cash used in financing activities	**(431)**	(393)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(12)**	(12)
Decrease in Cash and Cash Equivalents	**(458)**	(224)
Cash and Cash Equivalents		
Beginning of period	**654**	660
Cash and Cash Equivalents		
End of period	**196**	436

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Balance Sheet

(unaudited) *(millions of Canadian dollars)*	**March 31 2012**	December 31 2011 Adjusted (Note 1)
ASSETS		
Current Assets		
Cash and cash equivalents	**196**	654
Accounts receivable	**1,067**	1,094
Inventories	**239**	248
Other	**1,235**	1,114
	2,737	3,110
Plant, Property and Equipment, net of accumulated depreciation of $15,657 and $15,406, respectively	**32,175**	32,467
Equity Investments	**5,298**	5,077
Goodwill	**3,472**	3,534
Regulatory Assets	**1,655**	1,684
Intangibles and Other Assets	**1,558**	1,466
	46,895	47,338
LIABILITIES		
Current Liabilities		
Notes payable	**1,787**	1,863
Accounts payable	**2,146**	2,359
Accrued interest	**360**	365
Current portion of long-term debt	**424**	935
	4,717	5,522
Regulatory Liabilities	**309**	297
Deferred Amounts	**974**	929
Deferred Income Tax Liabilities	**3,664**	3,591
Long-Term Debt	**17,973**	17,724
Junior Subordinated Notes	**998**	1,016
	28,635	29,079
EQUITY		
Common shares, no par value	**12,026**	12,011
Issued and outstanding: March 31, 2012 - 704 million shares; December 31, 2011 - 704 million shares		
Preferred shares	**1,224**	1,224
Additional paid-in capital	**379**	380
Retained earnings	**4,670**	4,628
Accumulated other comprehensive loss	**(1,486)**	(1,449)
Controlling Interests	**16,813**	16,794
Non-controlling interests	**1,447**	1,465
Equity	**18,260**	18,259
	46,895	47,338

Contingencies and Guarantees (Note 8)

See accompanying notes to the condensed consolidated financial statements.

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

(unaudited) *(millions of Canadian dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at December 31, 2011	(643)	(281)	(525)	(1,449)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(90)**	-	-	**(90)**
Change in fair value of derivative instruments to hedge net investments in foreign operations[2]	**38**	-	-	**38**
Change in fair value of derivative instruments designated as cash flow hedges[3]	-	**(45)**	-	**(45)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][5]	-	**45**	-	**45**
Reclassification of actuarial losses and prior service costs on pension and other post-retirement benefit plans[6]	-	-	**10**	**10**
Other Comprehensive Income of equity investments [7]	-	**1**	**4**	**5**
Balance at March 31, 2012	**(695)**	**(280)**	**(511)**	**(1,486)**

(unaudited) *(adjusted Note 1)* *(millions of Canadian dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at December 31, 2010	(683)	(194)	(366)	(1,243)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(98)	-	-	(98)
Change in fair value of derivative instruments to hedge net investments in foreign operations[2]	49	-	-	49
Change in fair value of derivative instruments designated as cash flow hedges[3]	-	(54)	-	(54)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4][5]	-	46	-	46
Reclassification of actuarial losses and prior service costs on pension and other post-retirement benefit plans[6]	-	-	2	2
Other Comprehensive (Loss)/Income of equity investments [7]	-	(2)	4	2
Balance at March 31, 2011	(732)	(204)	(360)	(1,296)

(1) Net of income tax expense of $22 million and non-controlling interest losses of $17 million for the three months ended March 31, 2012 (2011 – expense of $29 million; loss of $18 million).

(2) Net of income tax expense of $11 million for the three months ended March 31, 2012 (2011 – expense of $19 million).

(3) Net of income tax recovery of $34 million and non-controlling interest losses of nil for the three months ended March 31, 2012 (2011 – recovery of $19 million; gain of $1 million).

(4) Net of income tax expense of $21 million and non-controlling interest losses of nil for the three months ended March 31, 2012 (2011 – expense of $25 million; gain of $2 million).

(5) Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net Income in the next 12 months are estimated to be $197 million ($120 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

(6) Net of income tax recovery of $4 million for the three months ended March 31, 2012 (2011 – expense of $1 million).

(7) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges, partially offset by changes in gains and losses on derivative instruments designated as cash flow hedges, net of income tax expense of $1 million for the three months ended March 31, 2012 (2011 – expense of $1 million).

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Equity

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	2012	2011 Adjusted (Note 1)
Common Shares		
Balance at beginning of period	**12,011**	11,745
Shares issued under dividend reinvestment plan	**-**	93
Proceeds from shares issued on exercise of stock options	**15**	21
Balance at end of period	**12,026**	11,859
Preferred Shares		
Balance at beginning and end of period	**1,224**	1,224
Additional Paid-In Capital		
Balance at beginning of period	**380**	349
Exercise of stock options, net of issuance	**(1)**	-
Balance at end of period	**379**	349
Retained Earnings		
Balance at beginning of period	**4,628**	4,273
Net income attributable to controlling interests	**366**	425
Common share dividends	**(310)**	(294)
Preferred share dividends	**(14)**	(14)
Balance at end of period	**4,670**	4,390
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,449)**	(1,243)
Other comprehensive loss	**(37)**	(53)
Balance at end of period	**(1,486)**	(1,296)
Equity Attributable to Controlling Interests	**16,813**	16,526
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,465**	1,157
Net income attributable to non-controlling interest	**35**	36
Other comprehensive loss attributable to non-controlling interest	**(17)**	(15)
Distributions to non-controlling interests	**(33)**	(27)
Other	**(3)**	(2)
Balance at end of period	**1,447**	1,149
Total Equity	**18,260**	17,675

See accompanying notes to the condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

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

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

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

Use of Estimates and Judgements

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

2. Changes in Accounting Policies

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

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

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

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

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

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

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

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

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

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

Changes in Accounting Policies for 2012

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

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

Future Accounting Changes

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

increase in disclosure regarding financial instruments which are subject to offsetting as described in this amendment.

3. Segmented Information

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	Natural Gas Pipelines		Oil Pipelines[1]		Energy		Corporate		Total	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Revenues	**1,085**	1,062	**259**	135	**567**	671	**-**	-	**1,911**	1,868
Income from equity investments	**46**	43	**-**	-	**14**	78	**-**	-	**60**	121
Plant operating costs and other	**(406)**	(332)	**(86)**	(36)	**(186)**	(217)	**(29)**	(24)	**(707)**	(609)
Commodity purchases resold	**-**	-	**-**	-	**(179)**	(238)	**-**	-	**(179)**	(238)
Depreciation and amortization	**(232)**	(228)	**(36)**	(23)	**(73)**	(66)	**(3)**	(3)	**(344)**	(320)
	493	545	**137**	76	**143**	228	**(32)**	(27)	**741**	822
Interest expense									**(242)**	(211)
Interest income and other									**31**	30
Income before Income Taxes									**530**	641
Income taxes expense									**(129)**	(180)
Net Income									**401**	461
Net Income Attributable to Non-Controlling Interests									**(35)**	(36)
Net Income Attributable to Controlling Interests									**366**	425
Preferred Share Dividends									**(14)**	(14)
Net Income Attributable to Common Shares									**352**	411

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

Total Assets

(unaudited) *(millions of Canadian dollars)*	**March 31, 2012**	December 31, 2011
Natural Gas Pipelines	**22,813**	23,161
Oil Pipelines	**9,378**	9,440
Energy	**13,675**	13,269
Corporate	**1,029**	1,468
	46,895	47,338

4. Income Taxes

At March 31, 2012, the total unrecognized tax benefit of uncertain tax positions is approximately $56 million (December 31, 2011 - $52 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the three months ended March 31, 2012 is $1 million of interest expense and nil for penalties (March 31, 2011 - $1 million for interest expense and nil for penalties). At March 31, 2012, the Company had $8 million accrued for interest expense and nil accrued for penalties (December 31, 2011 - $7 million accrued for interest expense and nil accrued for penalties).

The effective tax rates for the three-month periods ended March 31, 2012 and 2011 were 24 per cent and 28 per cent, respectively. The lower effective tax rate in 2012 was a result of a reduction in the Canadian statutory tax rate, changes in the proportion of income earned between Canadian and foreign jurisdictions and higher positive tax adjustments in 2012.

TransCanada expects the enactment of certain Canadian Federal tax legislation in the next twelve months which is expected to result in a favourable income tax adjustment of approximately $22 million. Otherwise, subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

5. Long-Term Debt

In the three months ended March 31, 2012, the Company capitalized interest related to capital projects of $74 million (March 31, 2011 - $97 million).

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

In March 2012, TransCanada PipeLines Limited issued US$500 million of 0.875 per cent Senior Notes due in 2015.

6. Employee Post-Retirement Benefits

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

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	Pension Benefit Plans **2012**	 2011	Other Post-retirement Benefit Plans **2012**	 2011
Service cost	**16**	14	**1**	-
Interest cost	**23**	23	**2**	2
Expected return on plan assets	**(28)**	(28)	**-**	-
Amortization of actuarial loss	**5**	3	**-**	-
Amortization of regulatory asset	**5**	4	**-**	-
Net Benefit Cost Recognized	**21**	16	**3**	2

7. Financial Instruments and Risk Management

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, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10.4 billion (US$10.4 billion) and a fair value of $12.9 billion (US$12.9 billion). At March 31, 2012, $97 million (December 31, 2011 - $79 million) was included in Other Current Assets, $83 million (December 31, 2011 - $66 million) was included in Intangibles and Other Assets, $4 million (December 31, 2011 - $15 million) was included in Accounts Payable and $30 million (December 31, 2011 - $41 million) was included in Deferred Amounts for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

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

Asset/(Liability) *(unaudited)* *(millions of Canadian dollars)*	**March 31, 2012** Fair Value(1)	**March 31, 2012** Notional or Principal Amount	December 31, 2011 Fair Value(1)	December 31, 2011 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2019)(2)	**128**	**US 4,150**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2012)	**18**	**US 1,165**	(4)	US 725
	146	**US 5,315**	89	US 4,575

(1) Fair values equal carrying values.

(2) Consolidated Net Income in first quarter 2012 included net realized gains of \$7 million (2011 – gains of \$5 million) related to the interest component of cross-currency swap settlements.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of Canadian dollars)*	**March 31, 2012** Carrying Amount(1)	**March 31, 2012** Fair Value(2)	December 31, 2011 Carrying Amount(1)	December 31, 2011 Fair Value(2)
Financial Assets				
Cash and cash equivalents	**196**	**196**	654	654
Accounts receivable and other(3)	**1,326**	**1,369**	1,359	1,403
Available-for-sale assets(3)	**34**	**34**	23	23
	1,556	**1,599**	2,036	2,080
Financial Liabilities(4)				
Notes payable	**1,787**	**1,787**	1,863	1,863
Accounts payable and deferred amounts(5)	**1,016**	**1,016**	1,329	1,329
Accrued interest	**360**	**360**	365	365
Long-term debt	**18,397**	**23,313**	18,659	23,757
Junior subordinated notes	**998**	**1,031**	1,016	1,027
	22,558	**27,507**	23,232	28,341

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

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

(3) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial assets of \$1,068 million (December 31, 2011 – \$1,094 million) in Accounts Receivable, \$33 million (December 31, 2011 – \$41 million) in Other Current Assets and \$259 million (December 31, 2011 - \$247 million) in Intangibles and Other Assets.

(4) Consolidated Net Income in first quarter 2012 included losses of \$15 million (2011 – losses of \$9 million) for fair value adjustments related to interest rate swap agreements on US\$350 million (2011 – US\$350 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(5) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial liabilities of \$886 million (December 31, 2011 – \$1,192 million) in Accounts Payable and \$130 million (December 31, 2011 - \$137 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

March 31, 2012 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$314**	**$189**	**$9**	**$19**
Liabilities	**$(329)**	**$(232)**	**$(13)**	**$(19)**
Notional Values				
Volumes[3]				
Purchases	**31,088**	**104**	**-**	**-**
Sales	**29,851**	**76**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**684**
U.S. dollars	**-**	**-**	**US 1,476**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2012[4]	**$(7)**	**$(14)**	**$6**	**$-**
Net realized gains/(losses) in the three months ended March 31, 2012[4]	**$15**	**$(10)**	**$9**	**$-**
Maturity dates	**2012-2016**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$40**	**$-**	**$-**	**$15**
Liabilities	**$(321)**	**$(23)**	**$(39)**	**$-**
Notional Values				
Volumes[3]				
Purchases	**21,455**	**6**	**-**	**-**
Sales	**8,704**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 42**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized (losses)/gains in the three months ended March 31, 2012[4]	**$(32)**	**$(6)**	**$-**	**$1**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2013-2015**

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $15 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three months ended March 31, 2012 were $2 million and were included in Interest Expense. In first quarter 2012, 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, 2012, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

2011 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading(1)				
Fair Values(2)(3)				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values(3)				
Volumes(4)				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US 1,269	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized (losses)/gains in the three months ended March 31, 2011(5)	$(1)	$(16)	$2	$(1)
Net realized (losses)/gains in the three months ended March 31, 2011(5)	$(1)	$(26)	$21	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships(6)(7)				
Fair Values(2)(3)				
Assets	$16	$3	$-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values(3)				
Volumes(4)				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US 73	US 600
Cross-currency	-	-	136/US 100	-
Net realized losses in the three months ended March 31, 2011(5)	$(43)	$(3)	$-	$(1)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

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

(2) Fair values equal carrying values.

(3) As at December 31, 2011.

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

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

(6) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million at December 31, 2011. Net realized gains on fair value hedges for the three 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.

(7) For the three months ended March 31, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of Canadian dollars)*	**March 31 2012**	December 31 2011
Current		
Other current assets	**503**	361
Accounts payable	**(607)**	(485)
Long term		
Intangibles and other assets	**263**	202
Deferred amounts	**(403)**	(349)

Derivatives in Cash Flow Hedging Relationships

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

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars, pre-tax)*	Cash Flow Hedges Power **2012**	 2011	 Natural Gas **2012**	 2011	 Foreign Exchange **2012**	 2011	 Interest **2012**	 2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**(66)**	(55)	**(10)**	(11)	**(3)**	(6)	**-**	-
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**47**	34	**13**	28	**-**	-	**6**	9
Losses on derivative instruments recognized in earnings (ineffective portion)	**(6)**	(2)	**(2)**	(1)	**-**	-	**-**	-

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at March 31, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2011 - $86 million), for which the Company had provided collateral of $53 million (2011 - $3 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2012, the Company would have been required to provide additional collateral of $57 million (2011 - $83 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the fair value hierarchy.

In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

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

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II. There were no transfers between Level II and Level III in first quarter 2012 and 2011.

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

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

(unaudited) (millions of Canadian dollars, pre-tax)	Quoted Prices in Active Markets (Level I) Mar 31 2012	Dec 31 2011	Significant Other Observable Inputs (Level II) Mar 31 2012	Dec 31 2011	Significant Unobservable Inputs (Level III) Mar 31 2012	Dec 31 2011	Total Mar 31 2012	Dec 31 2011
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**34**	36	**-**	-	**34**	36
Foreign exchange contracts	**-**	-	**187**	141	**-**	-	**187**	141
Power commodity contracts	**-**	-	**337**	201	**-**	-	**337**	201
Gas commodity contracts	**136**	124	**50**	55	**-**	-	**186**	179
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(19)**	(23)	**-**	-	**(19)**	(23)
Foreign exchange contracts	**-**	-	**(84)**	(102)	**-**	-	**(84)**	(102)
Power commodity contracts	**-**	-	**(621)**	(454)	**(11)**	(15)	**(632)**	(469)
Gas commodity contacts	**(228)**	(208)	**(25)**	(26)	**-**	-	**(253)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**34**	23	**-**	-	**-**	-	**34**	23
	(58)	(61)	**(141)**	(172)	**(11)**	(15)	**(210)**	(248)

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

Three months ended March 31 *(unaudited) (millions of Canadian dollars, pre-tax)*	Derivatives[(1)(2)] 2012	2011
Balance at January 1	**(15)**	(8)
New contracts	**-**	1
Total gains or losses included in OCI	**4**	(6)
Balance at March 31	**(11)**	(13)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) At March 31, 2012, there were no unrealized gains or losses included in Net Income attributable to derivatives that were still held at the reporting date (2011 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at March 31, 2012.

8. Contingencies and Guarantees

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

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. With respect to 2012, TransCanada currently expects spot prices to be less than the floor price for the year, therefore no amounts recorded in revenues in first quarter 2012 are expected to be repaid.

Sundance A PPA

The arbitration hearing to address the Sundance A force majeure and economic destruction claims dispute commenced April 9, 2012. The hearing is expected to conclude in May 2012, and TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe the PPA owner's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $30 million of pre-tax income for the three months ended March 31, 2012 and $188 million since the interruption began. The outcome of any arbitration process is not certain. However, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at March 31, 2012 of $74 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $831 million at March 31, 2012. The fair value of these Bruce Power guarantees at March 31, 2012 is estimated to be $30 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these assurances was estimated at March 31, 2012 to range from $136 million to a maximum of $494 million. The fair value of these guarantees at March 31, 2012 is estimated to be $80 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.