TRANSCANADA CORPORATION – THIRD QUARTER 2010

Quarterly Report to Shareholders

TransCanada Reports Solid Third Quarter Results
Advances Large Growth Program

CALGARY, Alberta – **November 3, 2010** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income applicable to common shares for third quarter 2010 of $377 million and comparable earnings of $374 million or $0.54 per share.

"Our solid third quarter financial results demonstrate TransCanada continues to move in the right direction. Over the coming months, the company is on track to bring into service a number of large-scale projects that are expected to generate significant earnings and cash flow in the years ahead," says Russ Girling, TransCanada's president and chief executive officer. "At the same time, we recognize our business environment will continue to be challenging in the short term with depressed power and natural gas prices, putting pressure on a portion of our existing operations. TransCanada is well positioned to benefit as the economy recovers and commodity prices improve."

Girling added he is pleased TransCanada continues to advance the remainder of its $21 billion capital plan. The 683 megawatt Halton Hills generating station in Ontario is now officially operational, and Maine's largest wind project – Kibby Wind – is complete. Girling also pointed out construction is well underway on both the Groundbirch pipeline that will connect the Alberta System to the northeast B.C. shale gas play, and on the Bison pipeline that will bring U.S. Rocky Mountain natural gas to market. Both projects should be operational by year's end.

In the first quarter of 2011, the company will also see capacity on its Keystone Pipeline System rise when the Cushing expansion begins operating and the total capacity of the line increases from 435,000 barrels per day (Bbl/d) to 591,000 Bbl/d.

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

- Net income applicable to common shares of $377 million or $0.54 per share
- Comparable earnings of $374 million or $0.54 per share
- Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.0 billion
- Funds generated from operations of $861 million
- Common share dividend of $0.40 per share.
- Invested an additional $1.3 billion to advance $21 billion capital program
- $700 million Halton Hills generating station was completed on time and on budget
- Began construction on the Groundbirch pipeline that will connect Montney shale gas, and on the Bison pipeline that will connect U.S. Rockies gas
- National Energy Board (NEB) approved a three year settlement with stakeholders on the Alberta System that sets the equity return at 9.7 per cent on deemed common equity of 40 per cent

Net income applicable to common shares for third quarter 2010 was $377 million ($0.54 per share) compared to $345 million ($0.50 per share) in third quarter 2009. Comparable earnings for third quarter 2010 were $374 million ($0.54 per share) compared to $335 million ($0.49 per share) in the same period in 2009.

The year over year increase was due to higher volumes and lower costs associated with higher plant availability at Bruce A for the quarter, higher generation and sales volumes in U.S. Power, higher earnings from the positive impact of recognizing the Alberta System 2010-2012 Revenue Requirement Settlement from its January 1, 2010 effective date, and lower net interest expense from increased capitalization of interest related to the company's large capital growth program. Partially offsetting these increases were lower realized power prices at Bruce B and Western Power.

Notable recent developments in Pipelines, Energy and Corporate include:

Pipelines:

- Construction of the second phase of the US$12 billion Keystone Pipeline System to expand nominal capacity to 591,000 Bbl/d and extend the pipeline system to Cushing, Oklahoma is over 90 per cent complete. This phase is expected to be operational in first quarter 2011 with contracted volumes of 530,000 Bbl/d.

  TransCanada's 500,000 Bbl/d Gulf Coast Expansion continues to move forward. The pipeline has binding, long-term commitments of 380,000 Bbl/d. TransCanada has received regulatory approval for the Canadian portion of the project and anticipates receiving regulatory approval for the U.S. portion of the project in the first half of 2011.

  The Gulf Coast Expansion project will increase commercial capacity of the Keystone Pipeline System to 1.1 million Bbl/d. Keystone will play an important role in linking a secure and growing supply of western Canadian and U.S. Williston Basin crude oil with the largest refining markets in the United States.

- On September 7 and September 13, 2010, TransCanada launched binding open seasons to obtain firm commitments from shippers to transport crude oil on the Cushing and Bakken Marketlink projects. The Cushing project would deliver crude from Cushing, Oklahoma to the U.S. Gulf Coast, while the Bakken initiative would transport oil from the Williston Basin to Cushing, Oklahoma or the U.S. Gulf Coast. The open seasons are expected to conclude in November 2010.

- On September 24, 2010, the NEB approved the Alberta System 2010-2012 Revenue Requirement Settlement Application. The Settlement has a three year term and incorporates an equity return of 9.7 per cent on deemed common equity of 40 per cent which is an increase from the return of 8.75 per cent on 35 per cent deemed common equity previously reflected in 2010 results.

- In August 2010, the company received final regulatory approvals and began construction of the Groundbirch pipeline. The pipeline is expected to be operational during November 2010. When complete, the approximate $155 million project will consist of 77 kilometres (km) (48 miles) of 36-inch diameter natural gas pipeline that will extend the Alberta System into northeast B.C. by connecting to natural gas supplies in the Montney shale gas formation. The Groundbirch pipeline has firm transportation contracts for 1.1 billion cubic feet per day by 2014.

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

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

- Construction on the US$600 million Bison natural gas pipeline project began in July 2010. The 487-km (303-mile) pipeline is expected to be operational in the fourth quarter of 2010. The project has long-term contracts for 407 mmcf/d.

- Work continues on the US$320 million Guadalajara pipeline project in Mexico. The 305-km (190-mile), 24 and 30-inch diameter natural gas pipeline has a contractual in-service date of first quarter 2011. The pipeline will move natural gas from Manzanillo to Guadalajara, Mexico's second largest city. Construction was approximately 40 per cent complete at the end of September 2010.

- The open season for the Alaska Pipeline Project concluded on July 30, 2010 having received multiple conditional bids from major industry players and others for significant volumes. The Alaska Pipeline Project will work to resolve the shipper and pipeline conditions placed on some of the bids by shippers through the next several months.

Energy:

- TransCanada's $700 million Halton Hills generating station went into service on September 1, 2010, on time and on budget. The 683 megawatt (MW) power plant is now operating under a 20-year Clean Energy Supply Contract with the Ontario Power Authority (OPA) that will generate stable earnings and cash flow over the next two decades. Halton Hills will generate enough power to meet the needs of approximately 700,000 homes.

- The second phase of the Kibby Wind power project went into service on October 26, 2010. This phase included 22 additional turbines. The two phases of the US$350 million project will produce a total of 132 MW of clean, renewable energy for the state of Maine – enough for approximately 50,000 homes. The first 22-turbine phase of the project began producing power in the fall of 2009.

- Construction of the 575 MW Coolidge generating station is approximately 90 per cent complete. The US$500 million generating station is anticipated to be in service by second quarter 2011.

- Refurbishment work on Bruce A Units 1 and 2 has progressed with the completion of a major milestone in October 2010 following the successful installation of the last of the 960 calandria tubes. Atomic Energy of Canada Limited (AECL) has begun de-staffing and will be substantially demobilized from Unit 2 by the end of 2010 and from Unit 1 by second quarter 2011.

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

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

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

Corporate:

- The Board of Directors of TransCanada declared a quarterly dividend of $0.40 per share for the quarter ending December 31, 2010, on TransCanada's outstanding common shares.

- On September 23, 2010, TransCanada's wholly-owned subsidiary, TransCanada PipeLines Limited, successfully completed an offering of US$1.0 billion of 3.80 per cent Senior Notes due October 1, 2020.

  The net proceeds of this offering will be used to partially fund capital projects of TransCanada, for general corporate purposes and to reduce short term debt.

- TransCanada is well positioned to fund its existing capital program through its growing internally-generated cash flow, its dividend reinvestment and share purchase plan and its continued access to capital markets. TransCanada will also continue to examine opportunities for portfolio management, including a role for TC PipeLines, LP in financing its capital program.

Teleconference – Audio and Slide Presentation:

TransCanada will hold a teleconference and webcast to discuss its 2010 third 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, including its $21 billion capital program, before opening the call to questions from analysts and members of the media.

Event:
TransCanada 2010 third quarter financial results teleconference and webcast

Date:
Wednesday, November 3, 2010

Time:
9:00 a.m. mountain daylight time (MDT) /11:00 a.m. eastern daylight time (EDT)

How:
Analysts, members of the media and other interested parties are invited to participate by calling 866.223.7781 or 416.340.8018 (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) November 10, 2010. Please call 800.408.3053 or 416.695.5800 (Toronto area) and enter pass code 5430321#.

With more than 50 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's network of wholly owned natural gas pipelines extends more than 60,000 kilometres (37,000 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

Forward-Looking Information
This news release may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada securityholders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future financial and operations plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects, projects and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, and strategies and goals for growth and expansion. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events

to differ materially from current expectations include, among others, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of TransCanada's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures
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 and Funds Generated from Operations in this news release.

These measures do not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP). They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of 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. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

Management uses the measures of Comparable Earnings, Comparable EBITDA and Comparable EBIT to better evaluate trends in the Company's underlying operations. Comparable Earnings, Comparable EBITDA and Comparable EBIT comprise Net Income Applicable to Common Shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant, but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating Comparable Earnings, Comparable EBITDA and Comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The table in the Consolidated Results of Operations section in the Management's Discussion and Analysis presents a reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income and Net Income Applicable to Common Shares. Comparable Earnings per Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the period.

Funds Generated from Operations comprises Net Cash Provided by Operations before changes in operating working capital. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Third Quarter 2010 Financial Highlights table in this news release.

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Third Quarter 2010 Financial Highlights

Operating Results

(unaudited) *(millions of dollars)*	Three months ended September 30 **2010**	2009	Nine months ended September 30 **2010**	2009
Revenues	**2,129**	2,049	**6,007**	6,195
Comparable EBITDA[1]	**1,007**	994	**2,936**	3,142
Net Income	**391**	345	**989**	993
Net Income Applicable to Common Shares	**377**	345	**958**	993
Comparable Earnings[1]	**374**	335	**977**	997
Cash Flows				
Funds generated from operations[1]	**861**	772	**2,519**	2,230
(Increase)/decrease in operating working capital	**(70)**	(201)	**(271)**	127
Net cash provided by operations	**791**	571	**2,248**	2,357
Capital Expenditures	**1,297**	1,557	**3,565**	3,943
Acquisitions, Net of Cash Acquired	**-**	653	**-**	902

Common Share Statistics

(unaudited)	Three months ended September 30 **2010**	2009	Nine months ended September 30 **2010**	2009
Net Income Per Share - Basic	**$0.54**	$0.50	**$1.39**	$1.55
Comparable Earnings Per Share[1]	**$0.54**	$0.49	**$1.42**	$1.56
Dividends Declared Per Share	**$0.40**	$0.38	**$1.20**	$1.14
Basic Common Shares Outstanding (millions)				
Average for the period	**692**	681	**689**	641
End of period	**693**	681	**693**	681

(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

Management's Discussion and Analysis (MD&A) dated November 2, 2010 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) for the three and nine months ended September 30, 2010. It should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TransCanada's 2009 Annual Report for the year ended December 31, 2009. 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. Unless otherwise indicated, "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries. Amounts are stated in Canadian dollars unless otherwise indicated. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TransCanada's 2009 Annual Report.

Forward-Looking Information

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Non-GAAP Measures

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EBITDA is an approximate measure of the Company's pre-tax operating cash flow. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

Management uses the measures of Comparable Earnings, Comparable EBITDA and Comparable EBIT to better evaluate trends in the Company's underlying operations. Comparable Earnings, Comparable EBITDA and Comparable EBIT comprise Net Income Applicable to Common Shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating Comparable Earnings, Comparable EBITDA and Comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The table in the Consolidated Results of Operations section of this MD&A presents a reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income and Net Income Applicable to Common Shares. Comparable Earnings Per Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the period.

Funds Generated from Operations comprises Net Cash Provided by Operations before changes in operating working capital. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Funds Generated from Operations table in the Liquidity and Capital Resources section of this MD&A.

Consolidated Results of Operations

Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income

For the three months ended September 30 *(unaudited)(millions of dollars except per share amounts)*	Pipelines **2010**	Pipelines 2009	Energy **2010**	Energy 2009	Corporate **2010**	Corporate 2009	Total **2010**	Total 2009
Comparable EBITDA[1]	**714**	730	**311**	292	**(18)**	(28)	**1,007**	994
Depreciation and amortization	**(232)**	(255)	**(94)**	(88)	**-**	-	**(326)**	(343)
Comparable EBIT[1]	**482**	475	**217**	204	**(18)**	(28)	**681**	651
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	**-**	-	**(3)**	-	**-**	-	**(3)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**-**	-	**7**	14	**-**	-	**7**	14
EBIT[1]	**482**	475	**221**	218	**(18)**	(28)	**685**	665
Interest expense							**(159)**	(216)
Interest expense of joint ventures							**(13)**	(17)
Interest income and other							**27**	43
Income taxes							**(120)**	(107)
Non-controlling interests							**(29)**	(23)
Net Income							**391**	345
Preferred share dividends							**(14)**	-
Net Income Applicable to Common Shares							**377**	345
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							**2**	-
Fair value adjustments of natural gas inventory in storage and forward contracts							**(5)**	(10)
Comparable Earnings[1]							**374**	335
Net Income Per Share – Basic and Diluted [2]							**$0.54**	$0.50

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

(2)

For the three months ended September 30 *(unaudited)*	**2010**	2009
Net Income Per Share	**$0.54**	$0.50
Specific items (net of tax):		
Fair value adjustments of natural gas inventory in storage and forward contracts	**-**	(0.01)
Comparable Earnings Per Share[1]	**$0.54**	$0.49

For the nine months ended September 30 *(unaudited)(millions of dollars except per share amounts)*	Pipelines		Energy		Corporate		Total	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Comparable EBITDA[1]	**2,178**	2,348	**824**	883	**(66)**	(89)	**2,936**	3,142
Depreciation and amortization	**(736)**	(773)	**(274)**	(261)	**-**	-	**(1,010)**	(1,034)
Comparable EBIT[1]	**1,442**	1,575	**550**	622	**(66)**	(89)	**1,926**	2,108
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	**-**	-	**(22)**	-	**-**	-	**(22)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**-**	-	**(8)**	(6)	**-**	-	**(8)**	(6)
EBIT[1]	**1,442**	1,575	**520**	616	**(66)**	(89)	**1,896**	2,102
Interest expense							**(528)**	(770)
Interest expense of joint ventures							**(44)**	(47)
Interest income and other							**33**	99
Income taxes							**(286)**	(320)
Non-controlling interests							**(82)**	(71)
Net Income							**989**	993
Preferred share dividends							**(31)**	-
Net Income Applicable to Common Shares							**958**	993
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							**13**	-
Fair value adjustments of natural gas inventory in storage and forward contracts							**6**	4
Comparable Earnings[1]							**977**	997
Net Income Per Share – Basic and Diluted[2]							**$1.39**	$1.55

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

(2)

For the nine months ended September 30 *(unaudited)*	**2010**	2009
Net Income Per Share	**$1.39**	$1.55
Specific items (net of tax):		
Fair value adjustments of U.S. Power derivative contracts	**0.02**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**0.01**	0.01
Comparable Earnings Per Share[1]	**$1.42**	$1.56

TransCanada's Net Income in third quarter 2010 was $391 million and Net Income Applicable to Common Shares was $377 million or $0.54 per share compared to $345 million or $0.50 per share in third quarter 2009. The $32 million increase in Net Income Applicable to Common Shares reflected:

- increased EBIT from Pipelines primarily due to the positive impact of recognizing the 2010 - 2012 Alberta System Revenue Requirement Settlement (Alberta System Settlement) from its effective date of January 1, 2010, lower depreciation and reduced operating, maintenance and administration (OM&A) costs, partially offset by the negative impact of a weaker U.S. dollar;

- increased EBIT from Energy primarily due to higher realized prices, volumes and capacity revenues for U.S. Power, and higher sales volumes at Bruce A, partially offset by lower realized power prices for Western Power and Bruce B, and decreased proprietary and third party storage revenues for Natural Gas Storage;

- decreased EBIT losses from Corporate primarily due to lower support and other corporate costs;

- decreased Interest Expense primarily due to increased capitalized interest and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by incremental interest on new debt issues in 2010;

- a negative impact on Interest Income and Other from lower gains in 2010 compared to 2009 on the translation of U.S. dollar-denominated working capital balances;

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

- dividends recorded for preferred shares issued in 2010 and third quarter 2009.

Comparable Earnings in third quarter 2010 were $374 million or $0.54 per share compared to $335 million or $0.49 per share for the same period in 2009. Comparable Earnings in third quarter 2010 excluded $2 million after tax ($3 million pre-tax) of net unrealized losses resulting from changes in the fair value of U.S. Power derivative contracts. Effective January 1, 2010, these unrealized gains and losses have been removed from Comparable Earnings as they are not expected to be representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not excluded from the computation of Comparable Earnings. Comparable Earnings in third quarter 2010 and 2009 also excluded net unrealized gains of $5 million after tax ($7 million pre-tax) and $10 million after tax ($14 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Pipelines and U.S. Energy EBIT is partially offset by the impact on U.S. dollar-denominated interest expense. The resultant net exposure is managed using derivatives, effectively further reducing the Company's exposure to changes in foreign exchange rates. The average U.S. dollar exchange rate was 1.04 for each of the three and nine month periods ended September 30, 2010 (2009 - 1.10 and 1.17, respectively).

TransCanada's Net Income in the first nine months of 2010 was $989 million and Net Income Applicable to Common Shares was $958 million or $1.39 per share compared to $993 million or $1.55 per share for the same period in 2009. The $35 million decrease in Net Income Applicable to Common Shares reflected:

- decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar, higher business development costs relating to the Alaska pipeline project and reduced revenues from certain U.S. pipelines, partially offset by the positive impact of recognizing the Alberta System Settlement, lower depreciation and reduced OM&A costs;

- decreased EBIT from Energy primarily due to lower overall realized power prices at Western Power, reduced volumes and higher operating costs at Bruce A, lower realized prices partially offset by higher volumes at Bruce B, reduced earnings at Bécancour and decreased proprietary and third party storage revenues for Natural Gas Storage, partially offset by increased volumes and capacity revenue from U.S. Power, and incremental earnings from Portlands Energy and Halton Hills, which went into service in April 2009 and September 2010, respectively;

- decreased EBIT losses from Corporate primarily due to lower support and other corporate costs;

- decreased Interest Expense primarily due to increased capitalized interest and the positive effect of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by incremental interest expense on new debt issues in 2010 and by higher losses in 2010 compared to 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates;

- the negative impact on Interest Income and Other due to lower gains in 2010 compared to 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and the negative impact from the translation of U.S. dollar-denominated working capital balances;

- decreased Income Taxes due to the net positive impact from income tax rate differentials, other income tax adjustments and lower pre-tax earnings; and

- dividends recorded for preferred shares issued in 2010 and third quarter 2009.

Net Income Per Share in the first nine months of 2010 was also reduced by $0.10 per share due to a seven per cent increase in the average number of common shares outstanding, compared to the same period in 2009, including the Company's issuance of 58.4 million common shares in second quarter 2009.

Comparable Earnings in the first nine months of 2010 were $977 million or $1.42 per share compared to $997 million or $1.56 per share for the same period in 2009. Comparable Earnings for the first nine months of 2010 excluded $13 million of after tax ($22 million pre-tax) net unrealized losses resulting from changes in the fair value of U.S. Power derivative contracts. Comparative amounts in 2009 were not excluded from the computation of Comparable Earnings. Comparable Earnings in the first nine months of 2010 and 2009 also excluded net unrealized losses of $6 million after tax ($8 million pre-tax) and $4 million after tax ($6 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Results from each of the segments for the first three and nine months in 2010 are discussed further in the Pipelines and Energy sections of this MD&A.

Pipelines

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

Pipelines Results

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

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.
(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.
(3) PipeLines LP's results reflect TransCanada's ownership interest in PipeLines LP of 38.2 per cent in the three and nine months ended September 30, 2010 (first six months of 2009 - 32.1 per cent; three months ended September 30, 2009 - 42.6 per cent).
(4) Portland's results reflect TransCanada's 61.7 per cent ownership interest.
(5) Represents general and administrative costs associated with certain of the Company's pipelines.
(6) Non-controlling interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TransCanada.

Net Income for Wholly Owned Canadian Pipelines

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

Canadian Pipelines

Canadian Mainline's net income for the three and nine months ended September 30, 2010 decreased $2 million and $5 million, respectively, compared to the same periods in 2009 primarily due to lower incentive earnings and a lower rate of return on common equity (ROE), as determined by the National Energy Board (NEB), of 8.52 per cent in 2010 compared to 8.57 per cent in 2009.

Canadian Mainline's Comparable EBITDA for the three and nine months ended September 30, 2010 of $257 million and $785 million, respectively, decreased $22 million and $66 million, respectively, compared to the same periods in 2009 primarily due to lower revenues as a result of lower income taxes and financial charges in the 2010 tolls, which are recovered on a flow-through basis and do not impact net income. The decrease in financial charges was primarily due to higher cost debt that matured in 2009 and early 2010.

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

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

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

U.S. Pipelines

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

GTN's Comparable EBITDA for the nine months ended September 30, 2010 decreased $22 million from the same period in 2009 primarily due to the sale of North Baja to PipeLines LP in July 2009 and the negative impact of a weaker U.S. dollar, partially offset by lower OM&A costs in 2010.

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

Business Development

Pipelines' Business Development Comparable EBITDA decreased $15 million in the nine months ended September 30, 2010 compared to the same period in 2009. EBITDA for the nine months ended

September 30, 2010 reflects increased expenses due to higher business development costs related to the continued advancement of the Alaska pipeline project, net of recoveries. The State of Alaska has agreed to reimburse certain of TransCanada's eligible pre-construction costs, as they are incurred and approved by the State, to a maximum of US$500 million. The State of Alaska is reimbursing up to 50 per cent of the eligible costs incurred prior to the close of the first binding open season on July 30, 2010. Commencing July 31, 2010, the State began reimbursing up to 90 per cent of the eligible costs. Together with applicable expenses, such reimbursements are shared proportionately with ExxonMobil, TransCanada's joint venture partner in developing the Alaska pipeline project.

Depreciation

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

Operating Statistics

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

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

(2) Field receipt volumes for the Alberta System for the nine months ended September 30, 2010 were 2,619 Bcf (2009 – 2,734 Bcf); average per day was 9.6 Bcf (2009 – 10.0 Bcf).

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

Mackenzie Gas Pipeline Project

As at September 30, 2010, TransCanada had advanced $145 million to the Aboriginal Pipeline Group (APG) with respect to the Mackenzie Gas Pipeline Project (MGP). TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The NEB is expected to release its decision on the project's application for a certificate of public convenience and necessity by December 2010. Project timing thereafter continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TransCanada, this may result in a reassessment of the carrying amount of the APG advances.

Energy

Energy's Comparable EBIT was $217 million in third quarter 2010 compared to $204 million in third quarter 2009. Comparable EBIT in third quarter 2010 excluded net unrealized losses of $3 million resulting from changes in the fair value of U.S. Power derivative contracts. Comparable EBIT in third quarter 2010 and 2009 also excluded net unrealized gains of $7 million and $14 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Energy's Comparable EBIT was $550 million in the first nine months of 2010 compared to $622 million in the same nine months of 2009. Comparable EBIT excluded net unrealized losses of $22 million resulting from changes in the fair value of U.S. Power derivative contracts. Comparable EBIT in the first nine months of 2010 and 2009 also excluded net unrealized losses of $8 million and $6 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Items excluded from Comparable Earnings are discussed further under the headings U.S. Power and Natural Gas Storage in this section.

Energy Results

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

(1) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.
(3) Includes phase one of Kibby Wind effective October 2009.

Canadian Power

Western and Eastern Canadian Power Comparable EBITDA(1)(2)

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

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.
(2) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.
(3) Includes sales of excess natural gas purchased for generation and thermal carbon black. Effective January 1, 2010, the net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues. Comparative results for 2009 reflect amounts reclassified from Other Commodity Purchases Resold to Other Revenues.
(4) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics(1)

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

(1) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.
(2) Excludes facilities that provide power to TransCanada under PPAs.

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

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

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

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

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

Western Power manages the sale of its supply volumes on a portfolio basis. A portion of its supply is sold into the spot market to assure supply in the event of an unexpected plant outage. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where Western Power would otherwise have to purchase electricity in the open market to fulfill its contractual sales obligations. Approximately 76 per cent of Western Power sales volumes were sold under contract in third quarter 2010, compared to 78 per cent in third quarter 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at September 30, 2010, Western Power had entered into fixed-price power sales contracts to sell approximately 2,400 gigawatt hours (GWh) for the remainder of 2010 and 7,300 GWh for 2011.

Eastern Power is focused on selling power under long-term contracts. In third quarter 2010 and 2009, all of Eastern Power's sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for the remainder of 2010 and 2011.

Bruce Power Results

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

(1) Revenues include Bruce A's fuel cost recoveries of $7 million and $21 million for the three and nine months ended September 30, 2010, respectively (2009 – $7 million and $28 million, respectively). Revenues also include Bruce B unrealized losses of $4 million and $5 million as a result of changes in the fair value of power derivatives for the three and nine months ended September 30, 2010, respectively (2009 – gains of $2 million and $4 million, respectively).
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.
(3) Includes revenues received under the floor price mechanism and contract settlements.
(4) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA increased $8 million to $89 million in third quarter 2010 compared to $81 million in third quarter 2009.

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

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $38 million to $54 million in third quarter 2010 compared to $92 million in third quarter 2009 primarily due to lower realized prices resulting from the expiration of fixed-price contracts at higher prices. Bruce B's volumes increased in third quarter 2010 compared to the same period in 2009 as a result of fewer surplus baseload generation (SBG) derates in 2010 as required by the Independent Electricity System Operator, partially offset by lower plant availability. Bruce B's plant availability in third quarter 2010 was 88 per cent with 35 outage days compared to an availability of 97 per cent and three outage days in the same period in 2009.

In second quarter 2009, Bruce B's contract with the Ontario Power Authority (OPA) was amended such that, beginning in 2009, annual net payments received under the floor price mechanism will not be subject to repayment in future years. Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues in the first nine months of 2010 are expected to be repaid.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased $83 million to $199 million in the nine months ended September 30, 2010 compared to the same period in 2009 as a result of lower volumes and higher operating costs due to higher planned and unplanned outage days at Bruce A, and lower realized prices at Bruce B, partially offset by higher volumes at Bruce B resulting from fewer SBG derates in 2010. The decrease in EBITDA for the nine months ended September 30, 2010 was partially offset by the impact of a payment made in first quarter 2010 from Bruce B to Bruce A regarding 2009 amendments to the agreement with the OPA. The net positive impact to TransCanada in 2010 reflected TransCanada's higher percentage ownership in Bruce A.

Under a contract with the OPA, all output from Bruce A in third quarter 2010 was sold at a fixed price of $64.71 per MWh (before recovery of fuel costs from the OPA) compared to $64.45 per MWh in third quarter 2009. All output from the Bruce B units was subject to a floor price of $48.96 per MWh in third quarter 2010 and $48.76 per MWh in third quarter 2009. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

Bruce B also enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price of $57 per MWh in third quarter 2010 reflected revenues recognized from both the floor price mechanism and contract sales, and decreased from the $66 per MWh in third quarter 2009 due to contracts expiring since that time. A significant portion of the remaining contracts will expire by the end of 2010, which is expected to result in a further reduction in realized prices at Bruce B for future periods. At September 30, 2010, Bruce B had sold forward approximately 200 GWh and 300 GWh, representing TransCanada's proportionate share, for the remainder of 2010 and 2011, respectively.

The overall plant availability percentage in 2010 is expected to be in the low 80's for the two operating Bruce A units and in the low 90's for the four Bruce B units. A planned outage of Bruce A Unit 3 began in late February 2010 and ended in late April 2010. A planned outage on Bruce B Unit 6 commenced in mid-May 2010 with the unit returning to service in late July 2010. A three week planned maintenance outage commenced on October 22, 2010 for Bruce B Unit 5.

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

U.S. Power

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

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

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of Comparable EBITDA.
(2) Includes phase one of Kibby Wind effective October 2009.
(3) Effective January 1, 2010, the net impact of derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets is presented on a net basis in Power Revenues. Comparative results for 2009 reflect amounts reclassified from Commodity Purchases Resold and Other Revenues to Power Revenues.
(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics[1]

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

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

U.S. Power's Comparable EBITDA for the three months ended September 30, 2010 was $116 million, an increase of $48 million compared to the same period in 2009. The increase was primarily due to higher realized prices, higher volumes of power sold and increased capacity revenues. For the nine months ended September 30, 2010, U.S. Power's Comparable EBITDA of $254 million increased $91 million from the same period in 2009 primarily due to higher capacity revenues, increased sales volumes and a first quarter 2010 adjustment of Ravenswood's 2009 operating costs, partially offset by the negative impact of a weaker U.S. dollar.

U.S. Power's Power Revenues for the three and nine months ended September 30, 2010 of $399 million and $884 million, respectively, increased from $222 million and $679 million in the same periods in 2009 primarily due to higher volumes of power sold in addition to higher realized power prices in third quarter 2010, partially offset by the negative impact of a weaker U.S. dollar. Capacity Revenues increased for the three and nine months ended September 30, 2010 to $77 million and $187 million, respectively, primarily due to higher capacity prices as a result of the long-planned retirement of a power generating facility owned by the New York Power Authority, which occurred at the end of January 2010. The increases in Capacity Revenues were partially offset by the impact of the Unit 30 outage from September 2008 to May 2009, which has a greater impact on 2010 capacity revenues due to the nature of the calculations.

Commodity Purchases Resold of $178 million and $435 million for the three and nine months ended September 30, 2010, respectively, increased from $78 million and $267 million in the same periods in 2009 primarily due to an increase in the quantity of power purchased for resale under power sales commitments in New England and New York, as well as higher power prices per MWh purchased in third quarter 2010, partially offset by the positive impact of a weaker U.S. dollar.

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

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

In the three and nine months ended September 30, 2010, 84 per cent and 91 per cent, respectively, of power sales volumes were sold under contract, compared to 85 per cent and 87 per cent for the same periods in 2009. U.S. Power is focused on selling the majority of its power under contract to wholesale, commercial and industrial customers, while managing a portfolio of power supplies sourced from its own generation and wholesale power purchases. To reduce its exposure to spot market prices on uncontracted volumes, as at September 30, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 3,400 GWh for the remainder of 2010 and 10,000 GWh for 2011, including financial contracts to effectively lock in a margin on forecasted generation. Certain contracted volumes are dependent on customer usage levels and actual amounts contracted in future periods will depend on market liquidity and other factors.

Comparable EBITDA excluded net unrealized losses of $3 million and $22 million in the three and nine months ended September 30, 2010, respectively, resulting from changes in the fair value of U.S. Power derivative contracts. Power is purchased under forward contracts to satisfy a significant portion of U.S. Power's wholesale, commercial and industrial power sales commitments, mitigating its exposure to fluctuations in spot market prices and effectively locking in a positive margin. In addition, power generation is managed by entering into contracts to sell a portion of power forecasted to be generated, while simultaneously entering into contracts to purchase the fuel required to generate the power, thereby reducing exposure to market price volatility and effectively locking in positive margins. Each of these contracts provide economic hedges which, in some cases, do not meet the specific criteria required for hedge accounting treatment and, therefore, are recorded at their fair value based on forward market prices. Effective January 1, 2010, the unrealized gains and losses from these contracts have been removed from Comparable EBITDA as they are not representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not excluded from the computation of Comparable EBITDA.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA for the three and nine month periods ended September 30, 2010, was $26 million and $95 million, respectively, compared to $45 million and $115 million for the same periods in 2009. The decrease in Comparable EBITDA in third quarter 2010 was primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas price spreads.

Comparable EBITDA excluded net unrealized gains of $7 million and net unrealized losses of $8 million in the three and nine months ended September 30, 2010, respectively (2009 – gains of $14 million and losses of $6 million, respectively), resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. TransCanada manages its proprietary natural gas storage earnings by simultaneously entering into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded in each period on proprietary natural gas inventory in storage and these forward contracts are not representative of the amounts that will be realized on settlement. The fair value of proprietary natural gas inventory in storage has been measured using a weighted average of forward prices for the following four months less selling costs.

Other Income Statement Items

Interest Expense

(unaudited)	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Interest on long-term debt[(1)]	**310**	317	**903**	981
Other interest and amortization	**9**	12	**62**	19
Capitalized interest	**(160)**	(113)	**(437)**	(230)
	159	216	**528**	770

(1) Includes interest for Junior Subordinated Notes.

Interest Expense for third quarter 2010 decreased $57 million to $159 million from $216 million in third quarter 2009 and for the nine months ended September 30, 2010 decreased $242 million to $528 million from $770 million for the nine months ended September 30, 2009. These decreases reflected increased capitalized interest to finance the Company's capital growth program in 2010, primarily due to Keystone construction, and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest. These decreases were partially offset by incremental interest expense on new debt issues of US$1.25 billion in June 2010 and $700 million in February 2009. The increase in Other Interest and Amortization for the nine months ended September 30, 2010 compared to 2009 was primarily due to higher losses in 2010 compared to 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates.

Interest Income and Other for third quarter 2010 decreased $16 million to $27 million from $43 million in third quarter 2009 and for the nine months ended September 30, 2010 decreased $66 million to $33 million from $99 million for the nine months ended September 2009. These decreases reflect the impact of a fluctuating U.S. dollar on the translation of U.S. dollar-denominated working capital balances. The decrease for the nine months ended September 30, 2010 was also due to lower gains in 2010 compared to 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income Taxes for the three and nine months ended September 30, 2010 were $120 million and $286 million, respectively, compared to $107 million and $320 million, respectively, for the same periods in 2009. The increase for third quarter 2010 compared to 2009 was primarily due to higher pre-tax earnings. The decrease for the nine months ended September 30, 2010 compared to 2009 was primarily due to the net positive impact from income tax rate differentials, other income tax adjustments and lower pre-tax earnings.

Liquidity and Capital Resources

TransCanada's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and to provide for planned growth. TransCanada's liquidity position remains solid, underpinned by predictable cash flow from operations, significant cash balances on hand from recent preferred share and debt issues, as well as unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$1.0 billion, maturing in November 2011, December 2012 and December 2012, respectively. These facilities also support the Company's two commercial paper programs in Canada. In addition, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada-operated affiliates was $118 million with maturity dates from 2011 through 2012. As at September 30, 2010, TransCanada had remaining capacity of $1.75 billion, $2.0 billion and US$1.75 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. In lieu of making cash dividend payments, a portion of declared common and preferred share dividends are expected to be paid in common shares issued under the Company's Dividend Reinvestment and Share Purchase Plan (DRP). TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section of this MD&A.

At September 30, 2010, the Company held Cash and Cash Equivalents of $1.1 billion compared to $1.0 billion at December 31, 2009. The increase in Cash and Cash Equivalents was primarily due to cash generated from operations, proceeds from the issuance of senior notes in second and third quarter 2010 and preferred shares in first and second quarter 2010, partially offset by capital expenditures and dividend payments.

Operating Activities

Funds Generated from Operations[1]

(unaudited) *(millions of dollars)*	Three months ended September 30 **2010**	2009	Nine months ended September 30 **2010**	2009
Cash Flows				
Funds generated from operations[1]	**861**	772	**2,519**	2,230
(Increase)/decrease in operating working capital	**(70)**	(201)	**(271)**	127
Net cash provided by operations	**791**	571	**2,248**	2,357

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

Net Cash Provided by Operations increased $220 million and decreased $109 million for the three and nine months ended September 30, 2010, respectively, compared to the same periods in 2009, reflecting increases in Funds Generated from Operations and changes in operating working capital. Funds Generated from Operations for the three and nine months ended September 30, 2010 were $861 million and $2.5 billion, respectively, compared to $772 million and $2.2 billion for the same periods in 2009. The increases for the three and nine months ended September 30, 2010 were primarily due to the income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed into service on June 30, 2010 and an increase in cash generated through earnings.

Investing Activities

TransCanada remains committed to executing its $21 billion capital expenditure program. For the three and nine months ended September 30, 2010, capital expenditures totalled $1.3 billion and $3.6

billion, respectively (2009 – $1.6 billion and $3.9 billion, respectively), primarily related to the construction of Keystone, refurbishment and restart of Bruce A Units 1 and 2, expansion of the Alberta System, and construction of the Bison and Guadalajara natural gas pipelines and Coolidge and Halton Hills power plants.

Financing Activities

In September 2010, TCPL issued US$1.0 billion of senior notes maturing October 1, 2020 and bearing interest at 3.80 per cent. These notes were issued under the US$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five and a half year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 5 preferred shareholders will have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.54 per cent.

In June 2010, TCPL issued senior notes of US$500 million and US$750 million maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, yielding 4.0 per cent per annum for the initial five year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 3 preferred shareholders will have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.28 per cent.

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

Dividends

On November 2, 2010, TransCanada's Board of Directors declared a quarterly dividend of $0.40 per share for the quarter ending December 31, 2010 on the Company's outstanding common shares. It is payable on January 31, 2011 to shareholders of record at the close of business on December 31, 2010. In addition, quarterly dividends of $0.2875 and $0.25 per preferred share were declared for Series 1 and Series 3 preferred shares, respectively, for the period ending December 31, 2010. The dividends are payable on December 31, 2010 to shareholders of record at the close of business on November 30, 2010. A quarterly dividend of $0.275 per preferred share was declared for Series 5 preferred shares for the period ending January 30, 2011. It is payable on January 31, 2011 to shareholders of record at the close of business on December 31, 2010.

TransCanada's Board of Directors approved the issuance of common shares from treasury at a three per cent discount under TransCanada's DRP for dividends payable on TransCanada's common and preferred shares, and TCPL's preferred shares. The Company reserves the right to alter the discount or return to fulfilling DRP participation by purchasing shares on the open market at any time. In the three and nine months ended September 30, 2010, TransCanada issued 2.9 million and 7.8 million (2009 – 2.5 million and 6.0 million) common shares, respectively, under its DRP, in lieu of making cash dividend payments of $101 million and $271 million, respectively (2009 - $73 million and $182 million, respectively).

Significant Accounting Policies and Critical Accounting Estimates

To prepare financial statements that conform with Canadian 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.

TransCanada's significant accounting policies and critical accounting estimates have remained unchanged since December 31, 2009. For further information on the Company's accounting policies and estimates refer to the MD&A in TransCanada's 2009 Annual Report.

Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TransCanada's 2009 Annual Report. Future accounting changes that will impact the Company are as follows:

Future Accounting Changes

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. As an SEC registrant, TransCanada prepares and files a "Reconciliation to United States GAAP" and also has the option to instead prepare and file its consolidated financial statements using U.S. GAAP. Previously, TransCanada disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. Prior to the developments noted below, the Company's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

Rate-Regulated Accounting

In accordance with Canadian GAAP, TransCanada currently follows specific accounting policies unique to a rate-regulated business. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain expenses and revenues to differ from that which may otherwise be expected under Canadian GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing differences are recorded as regulatory assets and regulatory liabilities on TransCanada's consolidated balance sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. As at September 30, 2010, TransCanada reported $1.7 billion of regulatory assets and $0.4 billion of regulatory liabilities using RRA in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities" which proposed a form of RRA under IFRS. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis. The IASB is now considering what form a future project might take, if any, to address RRA. As a result of these developments, TransCanada does not expect a final RRA standard under IFRS to be effective for 2011.

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

As a result of these developments related to RRA under IFRS, TransCanada cannot reasonably quantify the full impact that adopting IFRS would have on its financial position and future results if it proceeded with adopting IFRS. Alternatively, the impact of adopting U.S. GAAP is expected to be consistent with that currently reported in its publicly filed "Reconciliation to United States GAAP".

Contractual Obligations

At September 30, 2010, TransCanada had entered into agreements since December 31, 2009 totalling approximately $395 million to purchase construction materials and services for the Cartier Wind power and Bison natural gas pipeline projects. Other than these commitments and expected increased payments for long-term debt resulting from new debt issuances as discussed in the Liquidity and Capital Resources section of this MD&A, there have been no material changes to TransCanada's contractual obligations from December 31, 2009 to September 30, 2010, including payments due for the next five years and thereafter. TransCanada is currently assessing the impact on its contractual obligations resulting from the Government of Ontario's announcement of the cancellation of the Oakville power project. For further information on the Company's contractual obligations, refer to the MD&A in TransCanada's 2009 Annual Report.

Financial Instruments and Risk Management

TransCanada continues to manage and monitor its exposure to counterparty credit, liquidity and market 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 September 30, 2010, there were no significant amounts past due or impaired.

At September 30, 2010, the Company had a credit risk concentration of $308 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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

Natural Gas Inventory

At September 30, 2010, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $52 million (December 31, 2009 - $73 million). The change in fair value of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized losses of $1 million and $20 million, respectively (2009 - gains of $16 million and losses of $13 million, respectively), which were recorded as a decrease in Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized gains of $8 million and $12 million, respectively (2009 – losses of $2 million and gains of $7 million, respectively), which were included in Revenues.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TransCanada's consolidated VaR was $6 million at September 30, 2010 (December 31, 2009 – $12 million). The decrease from December 31, 2009 was primarily due to decreased commodity prices, reduced price volatility and fewer open positions in the U.S. Power portfolio.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At September 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10.1 billion (US$9.8 billion) and a fair value of $12.1 billion (US$11.8 billion). At September 30, 2010, $91 million (December 31, 2009 - $96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**September 30, 2010** Fair Value[1]	**September 30, 2010** Notional or Principal Amount	December 31, 2009 Fair Value[1]	December 31, 2009 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2015)	**87**	**U.S. 2,150**	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	**4**	**U.S. 400**	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	**-**	**-**	1	U.S. 100
	91	**U.S. 2,550**	96	U.S. 2,715

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**September 30, 2010** Carrying Amount	**September 30, 2010** Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**1,094**	**1,094**	997	997
Accounts receivable and other[2][3]	**1,557**	**1,615**	1,432	1,483
Available-for-sale assets[2]	**23**	**23**	23	23
	2,674	**2,732**	2,452	2,503
Financial Liabilities[1][3]				
Notes payable	**1,613**	**1,613**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,298**	**1,298**	1,538	1,538
Accrued interest	**325**	**325**	377	377
Long-term debt	**18,383**	**22,710**	16,664	19,377
Junior subordinated notes	**1,020**	**968**	1,036	976
Long-term debt of joint ventures	**889**	**1,021**	965	1,025
	23,528	**27,935**	22,267	24,980

(1) Consolidated Net Income in 2010 included gains of $11 million (2009 – $9 million) for fair value adjustments related to interest rate swap agreements on US$150 million (2009 – US$300 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At September 30, 2010, the Consolidated Balance Sheet included financial assets of $1,123 million (December 31, 2009 – $966 million) in Accounts Receivable, $41 million (December 31, 2009 – nil) in Other Current Assets and $416 million (December 31, 2009 - $489 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for certain long-term debt which is recorded at fair value.

(4) At September 30, 2010, the Consolidated Balance Sheet included financial liabilities of $1,261 million (December 31, 2009 – $1,513 million) in Accounts Payable and $37 million (December 31, 2009 - $25 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

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

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $11 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2010 were $1 million and $3 million, respectively, and were included in Interest Expense. In third quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Losses included in Net Income for the three and nine months ended September 30, 2010 were nil and $1 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and nine months ended September 30, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2009 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values(1)(2)					
Assets	$150	$107	$5	-	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values(2)					
Volumes(3)					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/ U.S. 157	-
Net unrealized (losses)/gains in the period(4)					
Three months ended September 30, 2009	$(8)	$21	$(1)	$2	$(7)
Nine months ended September 30, 2009	$11	$(4)	$1	$4	$20
Net realized gains/(losses) in the period(4)					
Three months ended September 30, 2009	$23	$(43)	$1	$11	$(5)
Nine months ended September 30, 2009	$53	$(56)	-	$28	$(14)
Maturity dates(2)	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships(5)(6)					
Fair Values(1)(2)					
Assets	$175	$2	-	-	$15
Liabilities	$(148)	$(22)	-	$(43)	$(50)
Notional Values(2)					
Volumes(3)					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period(4)					
Three months ended September 30, 2009	$30	$(8)	-	-	$(10)
Nine months ended September 30, 2009	$108	$(28)	-	-	$(27)
Maturity dates(2)	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.
(2) As at December 31, 2009.
(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.
(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other

Comprehensive Income and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million at December 31, 2009. Net realized gains on fair value hedges for the three and nine months ended September 30, 2009 were $1 million and $3 million, respectively, and were included in Interest Expense. In third quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three and nine months ended September 30, 2009 included gains of $1 million and $2 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and nine months ended September 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

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

Controls and Procedures

As of September 30, 2010, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of 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 as at September 30, 2010.

During the recent fiscal quarter, 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 2009 Annual Report, the Company's earnings outlook for 2010 has declined due to the continued negative impact of reduced market prices for power on Energy's results. As discussed in the Recent Developments section of this MD&A, the Company has delayed recognition of EBITDA from Keystone, which is to be offset by higher capitalized interest. For further information on outlook, refer to the MD&A in TransCanada's 2009 Annual Report.

Recent Developments

Pipelines

Keystone

The first phase of Keystone extending from Hardisty, Alberta has commenced serving markets in Wood River and Patoka, Illinois. As part of the NEB's approval to begin operations, Keystone will operate at a reduced maximum operating pressure (MOP) on the Canadian conversion segment of the pipeline, which will reduce throughput capacity below the initial nominal capacity of 435,000 barrels per day (Bbl/d). Additional in-line inspections have been completed and approval from the NEB to remove the MOP restriction is anticipated in fourth quarter 2010.

Construction of the second phase of Keystone to expand nominal capacity to 591,000 Bbl/d and extend the pipeline to Cushing, Oklahoma was over 90 per cent complete at September 30, 2010. Commercial in service of this phase is expected in first quarter 2011.

Keystone is planning to construct and operate an expansion and extension of the pipeline system that will provide additional capacity of 500,000 Bbl/d from Western Canada to the U.S. Gulf Coast in first quarter 2013. The Keystone Gulf Coast expansion will extend from Hardisty to a delivery point near Port Arthur, Texas. In March 2010, the NEB approved the Company's application to construct and operate the Canadian portion of the Keystone expansion. In April 2010, the Department of State, the lead agency for U.S. federal regulatory approvals, issued a Draft Environmental Impact Statement which concluded that Keystone's expansion to the Gulf Coast would have limited environmental impact. The regulatory process conducted by the Department of State continues with final regulatory approvals expected in the first half of 2011. Construction is expected to begin shortly thereafter.

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

In response to significant market demand, the Company is pursuing opportunities to attract growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to Keystone for delivery to major U.S. refining markets. On September 13, 2010, the Company commenced a binding open season to obtain firm commitments from interested parties for the Bakken Marketlink Project, which would transport crude oil from Baker, Montana to Cushing and to the U.S. Gulf Coast. If the open season, which is expected to close in November 2010, is successful, commercial in service is anticipated in first quarter 2013.

The total capital cost of Keystone is expected to be approximately US$12 billion. Approximately US$7 billion has been spent to date, including approximately US$1 billion for the expansion to the Gulf Coast, with the remaining US$5 billion to be invested between now and the end of 2012. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with its customers.

Although the first phase of Keystone is now in commercial service, cash flow related to Keystone, other than general, administrative and support costs, is being capitalized until the MOP restriction has been removed and the pipeline is capable of operating at pipeline design pressure. Following this, TransCanada expects Keystone to begin recording EBITDA, which is anticipated to increase through 2011, 2012 and 2013 as subsequent phases are placed in service. Based on current long-term commitments of 910,000 Bbl/d, Keystone is expected to generate EBITDA of approximately US$1.2 billion in 2013, its first full year of commercial operation serving both the U.S. Midwest and Gulf Coast markets. If volumes increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate approximately US$1.5 billion of annual EBITDA. In the future, Keystone can be economically expanded from 1.1 million Bbl/d to 1.5 million Bbl/d in response to additional market demand.

Canadian Mainline

In any year, tolls on the Canadian Mainline are partially based on projected throughput volumes for the year. Estimated throughput volumes for 2010 are now expected to be lower than was used in setting the tolls for 2010. As a result, amounts collected through tolls are projected to be approximately 15 per cent less than anticipated in 2010. This shortfall is deferred for accounting purposes as it is expected to be collected in future tolls under the framework regulated by the NEB.

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

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

Alberta System

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

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

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

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

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

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

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

TQM

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

Bison

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

Alaska

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

Guadalajara

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

Energy

Bruce

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

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

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

Halton Hills

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

Kibby Wind

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

Coolidge

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

Oakville

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

Share Information

As at October 29, 2010, TransCanada had 696 million issued and outstanding common shares, and nine million outstanding options to purchase common shares, of which seven million were exercisable. As at October 29, 2010, TransCanada had 22 million Series 1, 14 million Series 3 and 14 million Series 5 issued and outstanding preferred shares that are convertible to 22 million Series 2, 14 million Series 4 and 14 million Series 6 preferred shares, respectively.

Selected Quarterly Consolidated Financial Data[1]

(unaudited) *(millions of dollars except per share amounts)*	**2010**			2009				2008
	Third	**Second**	**First**	Fourth	Third	Second	First	Fourth
Revenues	**2,129**	**1,923**	**1,955**	1,986	2,049	1,984	2,162	2,234
Net Income	**391**	**295**	**303**	387	345	314	334	277
Share Statistics								
Net income per common share – Basic	**$0.54**	**$0.41**	**$0.43**	$0.56	$0.50	$0.50	$0.54	$0.47
Net income per common share – Diluted	**$0.54**	**$0.41**	**$0.43**	$0.56	$0.50	$0.50	$0.54	$0.46
Dividend declared per common share	**$0.40**	**$0.40**	**$0.40**	$0.38	$0.38	$0.38	$0.38	$0.36

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been restated to conform with the current year's presentation.

Factors Impacting Quarterly Financial Information

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

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

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

- Third quarter 2010, Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 – 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized losses of $3 million pre-tax ($2 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized gains of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Second quarter 2010, Energy's EBIT included net unrealized gains of $9 million pre-tax ($6 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized gains of $6 million pre-tax ($4 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income decreased $58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.

- First quarter 2010, Energy's EBIT included net unrealized losses of $28 million pre-tax ($17 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized losses of $21 million pre-tax ($15 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Fourth quarter 2009, Pipelines' EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TransCanada's reduced ownership interest in PipeLines LP after PipeLines LP issued common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.

- Third quarter 2009, Energy's EBIT included net unrealized gains of $14 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

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

- First quarter 2009, Energy's EBIT included net unrealized losses of $13 million pre-tax ($9 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Fourth quarter 2008, Energy's EBIT included net unrealized gains of $7 million pre-tax ($6 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included net unrealized losses of $57 million pre-tax ($39 million after tax) due to changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates but which did not qualify as hedges for accounting purposes.

Consolidated Income

(unaudited) *(millions of dollars except per share amounts)*	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Revenues	**2,129**	2,049	**6,007**	6,195
Operating and Other Expenses				
Plant operating costs and other	**817**	836	**2,328**	2,443
Commodity purchases resold	**301**	205	**773**	616
Depreciation and amortization	**326**	343	**1,010**	1,034
	1,444	1,384	**4,111**	4,093
Financial Charges/(Income)				
Interest expense	**159**	216	**528**	770
Interest expense of joint ventures	**13**	17	**44**	47
Interest income and other	**(27)**	(43)	**(33)**	(99)
	145	190	**539**	718
Income before Income Taxes and Non-Controlling Interests	**540**	475	**1,357**	1,384
Income Taxes				
Current	**(49)**	14	**(167)**	103
Future	**169**	93	**453**	217
	120	107	**286**	320
Non-Controlling Interests				
Non-controlling interest in PipeLines LP	**25**	19	**64**	51
Preferred share dividends of subsidiary	**6**	6	**17**	17
Non-controlling interest in Portland	**(2)**	(2)	**1**	3
	29	23	**82**	71
Net Income	**391**	345	**989**	993
Preferred Share Dividends	**14**	-	**31**	-
Net Income Applicable to Common Shares	**377**	345	**958**	993
Net Income Per Share - Basic and Diluted	**$0.54**	$0.50	**$1.39**	$1.55
Average Shares Outstanding – Basic (millions)	**692**	681	**689**	641
Average Shares Outstanding – Diluted (millions)	**693**	682	**690**	642

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) (millions of dollars)	Three months ended September 30 2010	 2009	Nine months ended September 30 2010	 2009
Cash Generated From Operations				
Net income	**391**	345	**989**	993
Depreciation and amortization	**326**	343	**1,010**	1,034
Future income taxes	**169**	93	**453**	217
Non-controlling interests	**29**	23	**82**	71
Employee future benefits funding less than/(in excess) of expense	**8**	(22)	**(36)**	(79)
Other	**(62)**	(10)	**21**	(6)
	861	772	**2,519**	2,230
(Increase)/decrease in operating working capital	**(70)**	(201)	**(271)**	127
Net cash provided by operations	**791**	571	**2,248**	2,357
Investing Activities				
Capital expenditures	**(1,297)**	(1,557)	**(3,565)**	(3,943)
Acquisitions, net of cash acquired	**-**	(653)	**-**	(902)
Deferred amounts and other	**(221)**	(20)	**(430)**	(294)
Net cash used in investing activities	**(1,518)**	(2,230)	**(3,995)**	(5,139)
Financing Activities				
Dividends on common and preferred shares	**(184)**	(186)	**(567)**	(535)
Distributions paid to non-controlling interests	**(28)**	(25)	**(83)**	(76)
Notes payable (repaid)/issued, net	**(44)**	77	**(53)**	(607)
Long-term debt issued, net of issue costs	**1,021**	207	**2,337**	3,267
Reduction of long-term debt	**(146)**	(9)	**(429)**	(509)
Long-term debt of joint ventures issued	**86**	93	**164**	201
Reduction of long-term debt of joint ventures	**(93)**	(52)	**(232)**	(108)
Common shares issued, net of issue costs	**6**	2	**20**	1,805
Preferred shares issued, net of issue costs	**-**	539	**679**	539
Net cash provided by financing activities	**618**	646	**1,836**	3,977
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(8)**	(63)	**8**	(97)
(Decrease)/Increase in Cash and Cash Equivalents	**(117)**	(1,076)	**97**	1,098
Cash and Cash Equivalents				
Beginning of period	**1,211**	3,482	**997**	1,308
Cash and Cash Equivalents				
End of period	**1,094**	2,406	**1,094**	2,406
Supplementary Cash Flow Information				
Net income taxes (refunded)/paid	**(26)**	(63)	**17**	50
Interest paid, net of capitalized interest	**215**	297	**573**	834

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**September 30, 2010**	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	**1,094**	997
Accounts receivable	**1,123**	966
Inventories	**452**	511
Other	**772**	701
	3,441	3,175
Plant, Property and Equipment	**35,555**	32,879
Goodwill	**3,696**	3,763
Regulatory Assets	**1,491**	1,524
Intangibles and Other Assets	**2,435**	2,500
	46,618	43,841
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**1,613**	1,687
Accounts payable	**2,162**	2,195
Accrued interest	**325**	377
Current portion of long-term debt	**455**	478
Current portion of long-term debt of joint ventures	**28**	212
	4,583	4,949
Regulatory Liabilities	**332**	385
Deferred Amounts	**896**	743
Future Income Taxes	**3,143**	2,856
Long-Term Debt	**17,928**	16,186
Long-Term Debt of Joint Ventures	**861**	753
Junior Subordinated Notes	**1,020**	1,036
	28,763	26,908
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**706**	705
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland	**81**	80
	1,176	1,174
Shareholders' Equity	**16,679**	15,759
	46,618	43,841

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended September 30 **2010**	 2009	Nine months ended September 30 **2010**	 2009
Net Income	**391**	345	**989**	993
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(127)**	(230)	**(47)**	(381)
Change in gains and losses on hedges of investments in foreign operations(2)	**47**	113	**27**	209
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**(52)**	16	**(173)**	80
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	**8**	(1)	**6**	(6)
Other Comprehensive (Loss)/Income	**(124)**	(102)	**(187)**	(98)
Comprehensive Income	**267**	243	**802**	895

(1) Net of income tax expense of $36 million and $21 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of $68 million and $68 million, respectively).

(2) Net of income tax expense of $19 million and $11 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of $50 million and $102 million, respectively).

(3) Net of income tax recovery of $33 million and $117 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of $4 million and $20 million, respectively).

(4) Net of income tax expense of $4 million and $21 million for the three and nine months ended September 30, 2010, respectively (2009 – expense of $4 million and $4 million, respectively).

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges	Total
Balance at December 31, 2009	**(592)**	**(40)**	**(632)**
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(47)**	**-**	**(47)**
Change in gains and losses on hedges of investments in foreign operations[2]	**27**	**-**	**27**
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**-**	**(173)**	**(173)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][5]	**-**	**6**	**6**
Balance at September 30, 2010	**(612)**	**(207)**	**(819)**

Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(381)	-	(381)
Change in gains and losses on hedges of investments in foreign operations[2]	209	-	209
Changes in gains and losses on derivative instruments designated as cash flow hedges[3]	-	80	80
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	-	(6)	(6)
Balance at September 30, 2009	(551)	(19)	(570)

(1) Net of income tax expense of $21 million for the nine months ended September 30, 2010 (2009 - $68 million expense).
(2) Net of income tax expense of $11 million for the nine months ended September 30, 2010 (2009 - $102 million expense).
(3) Net of income tax recovery of $117 million for the nine months ended September 30, 2010 (2009 - $20 million expense).
(4) Net of income tax expense of $21 million for the nine months ended September 30, 2010 (2009 - $4 million expense).
(5) Losses related to cash flow hedges reported in Accumulated Other Comprehensive (Loss)/Income and expected to be reclassified to Net Income in the next 12 months are estimated to be $95 million ($56 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

See accompanying notes to the consolidated financial statements.

Consolidated Shareholders' Equity

(unaudited) *(millions of dollars)*	Nine months ended September 30 **2010**	2009
Common Shares		
Balance at beginning of period	**11,338**	9,264
Shares issued under dividend reinvestment plan	**271**	182
Proceeds from shares issued on exercise of stock options	**20**	13
Proceeds from shares issued under public offering, net of issue costs	**-**	1,792
Balance at end of period	**11,629**	11,251
Preferred Shares		
Balance at beginning of period	**539**	-
Proceeds from shares issued under public offering, net of issue costs	**685**	539
Balance at end of period	**1,224**	539
Contributed Surplus		
Balance at beginning of period	**328**	279
Issuance of stock options	**2**	3
Increased ownership in PipeLines LP	**-**	49
Balance at end of period	**330**	331
Retained Earnings		
Balance at beginning of period	**4,186**	3,827
Net income	**989**	993
Common share dividends	**(829)**	(754)
Preferred share dividends	**(31)**	-
Balance at end of period	**4,315**	4,066
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	**(632)**	(472)
Other comprehensive (loss)/income	**(187)**	(98)
Balance at end of period	**(819)**	(570)
	3,496	3,496
Total Shareholders' Equity	**16,679**	15,617

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

(Unaudited)

1. Significant Accounting Policies

The consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The accounting policies applied are consistent with those outlined in TransCanada's annual audited Consolidated Financial Statements for the year ended December 31, 2009. These Consolidated Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2009 audited Consolidated Financial Statements included in TransCanada's 2009 Annual Report. Unless otherwise indicated, "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TransCanada's Annual Report. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

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

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

In preparing these financial statements, 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 consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

2. Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TransCanada's 2009 Annual Report. Future accounting changes that will impact the Company are as follows:

Future Accounting Changes

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. As an SEC registrant, TransCanada prepares and files a "Reconciliation to United States GAAP" and also has the option to instead prepare and file its consolidated financial statements using U.S. GAAP. Previously, TransCanada disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. Prior to the developments noted below, the Company's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

Rate-Regulated Accounting

In accordance with Canadian GAAP, TransCanada currently follows specific accounting policies unique to a rate-regulated business. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain expenses and revenues to differ from that which may otherwise be expected under Canadian GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing differences are recorded as regulatory assets and regulatory liabilities on TransCanada's consolidated balance sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. As at September 30, 2010, TransCanada reported $1.7 billion of regulatory assets and $0.4 billion of regulatory liabilities using RRA in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities" which proposed a form of RRA under IFRS. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis. The IASB is now considering what form a future project might take, if any, to address RRA. As a result of these developments, TransCanada does not expect a final RRA standard under IFRS to be effective for 2011.

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

As a result of these developments related to RRA under IFRS, TransCanada cannot reasonably quantify the full impact that adopting IFRS would have on its financial position and future results if it proceeded with adopting IFRS. Alternatively, the impact of adopting U.S. GAAP is expected to be consistent with that currently reported in its publicly filed "Reconciliation to United States GAAP".

3. Segmented Information

Three months ended September 30	Pipelines		Energy[1]		Corporate		Total	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Revenues	**1,080**	1,152	**1,049**	897	**-**	-	**2,129**	2,049
Plant operating costs and other	**(366)**	(422)	**(433)**	(386)	**(18)**	(28)	**(817)**	(836)
Commodity purchases resold	**-**	-	**(301)**	(205)	**-**	-	**(301)**	(205)
Depreciation and amortization	**(232)**	(255)	**(94)**	(88)	**-**	-	**(326)**	(343)
	482	475	**221**	218	**(18)**	(28)	**685**	665
Interest expense							**(159)**	(216)
Interest expense of joint ventures							**(13)**	(17)
Interest income and other							**27**	43
Income taxes							**(120)**	(107)
Non-controlling interests							**(29)**	(23)
Net Income							**391**	345
Preferred share dividends							**(14)**	-
Net Income Applicable to Common Shares							**377**	345

Nine months ended September 30	Pipelines		Energy[1]		Corporate		Total	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Revenues	**3,270**	3,558	**2,737**	2,637	**-**	-	**6,007**	6,195
Plant operating costs and other	**(1,092)**	(1,210)	**(1,170)**	(1,144)	**(66)**	(89)	**(2,328)**	(2,443)
Commodity purchases resold	**-**	-	**(773)**	(616)	**-**	-	**(773)**	(616)
Depreciation and amortization	**(736)**	(773)	**(274)**	(261)	**-**	-	**(1,010)**	(1,034)
	1,442	1,575	**520**	616	**(66)**	(89)	**1,896**	2,102
Interest expense							**(528)**	(770)
Interest expense of joint ventures							**(44)**	(47)
Interest income and other							**33**	99
Income taxes							**(286)**	(320)
Non-controlling interests							**(82)**	(71)
Net Income							**989**	993
Preferred share dividends							**(31)**	-
Net Income Applicable to Common Shares							**958**	993

(1) Effective January 1, 2010, the Company records in Revenues on a net basis, realized and unrealized gains and losses on derivatives used to purchase and sell power, natural gas and fuel oil in order to manage Energy's assets. Comparative figures for 2009 reflect amounts reclassified from Commodity Purchases Resold and Plant Operating Costs and Other to Revenues.

Total Assets

(unaudited)(millions of dollars)	**September 30, 2010**	December 31, 2009
Pipelines	**31,507**	29,508
Energy	**13,037**	12,477
Corporate	**2,074**	1,856
	46,618	43,841

4. Long-Term Debt

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

In June 2010, TCPL issued senior notes of US$500 million and US$750 million maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US$4.0 billion debt shelf prospectus filed in December 2009.

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

5. Share Capital

Preferred Share Issuances

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five and a half year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter.

The Series 5 preferred shareholders will have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, yielding 4.0 per cent per annum for the initial five year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter.

The Series 3 preferred shareholders will have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.28 per cent.

Dividend Reinvestment and Share Purchase Plan

In the three and nine months ended September 30, 2010, TransCanada issued 2.9 million and 7.8 million (2009 – 2.5 million and 6.0 million) common shares, respectively, under its Dividend Reinvestment and Share Purchase Plan (DRP), in lieu of making cash dividend payments of $101 million and $271 million, respectively (2009 - $73 million and $182 million, respectively). The dividends under the DRP were paid with common shares issued from treasury.

6. Financial Instruments and Risk Management

TransCanada continues to manage and monitor its exposure to counterparty credit, liquidity and market 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 September 30, 2010, there were no significant amounts past due or impaired.

At September 30, 2010, the Company had a credit risk concentration of $308 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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

Natural Gas Inventory

At September 30, 2010, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $52 million (December 31, 2009 - $73 million). The change in fair value of proprietary natural gas inventory in storage in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized losses of $1 million and $20 million, respectively (2009 - gains of $16 million and losses of $13 million, respectively), which were recorded as a decrease in Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three and nine months ended September 30, 2010 resulted in net pre-tax unrealized gains of $8 million and $12 million, respectively (2009 – losses of $2 million and gains of $7 million, respectively), which were included in Revenues.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TransCanada's consolidated VaR was $6 million at September 30, 2010 (December 31, 2009 – $12 million). The decrease from December 31, 2009 was primarily due to decreased commodity prices, reduced price volatility and fewer open positions in the U.S. Power portfolio.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At September 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10.1 billion (US$9.8 billion) and a fair value of $12.1 billion (US$11.8 billion). At September 30, 2010, $91 million (December 31, 2009 - $96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

	September 30, 2010		December 31, 2009	
Asset/(Liability) *(unaudited)* *(millions of dollars)*	**Fair Value**[1]	**Notional or Principal Amount**	Fair Value[1]	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2015)	**87**	**U.S. 2,150**	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	**4**	**U.S. 400**	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	**-**	**-**	1	U.S. 100
	91	**U.S. 2,550**	96	U.S. 2,715

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

	September 30, 2010		December 31, 2009	
(unaudited) *(millions of dollars)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets(1)				
Cash and cash equivalents	**1,094**	**1,094**	997	997
Accounts receivable and other(2)(3)	**1,557**	**1,615**	1,432	1,483
Available-for-sale assets(2)	**23**	**23**	23	23
	2,674	**2,732**	2,452	2,503
Financial Liabilities(1)(3)				
Notes payable	**1,613**	**1,613**	1,687	1,687
Accounts payable and deferred amounts(4)	**1,298**	**1,298**	1,538	1,538
Accrued interest	**325**	**325**	377	377
Long-term debt	**18,383**	**22,710**	16,664	19,377
Junior subordinated notes	**1,020**	**968**	1,036	976
Long-term debt of joint ventures	**889**	**1,021**	965	1,025
	23,528	**27,935**	22,267	24,980

(1) Consolidated Net Income in 2010 included gains of $11 million (2009 – $9 million) for fair value adjustments related to interest rate swap agreements on US$150 million (2009 – US$300 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At September 30, 2010, the Consolidated Balance Sheet included financial assets of $1,123 million (December 31, 2009 – $966 million) in Accounts Receivable, $41 million (December 31, 2009 – nil) in Other Current Assets and $416 million (December 31, 2009 - $489 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for certain long-term debt which is recorded at fair value.

(4) At September 30, 2010, the Consolidated Balance Sheet included financial liabilities of $1,261 million (December 31, 2009 – $1,513 million) in Accounts Payable and $37 million (December 31, 2009 - $25 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

September 30, 2010
(unaudited)
(all amounts in millions unless otherwise indicated)

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

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $11 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2010 were $1 million and $3 million, respectively, and were included in Interest Expense. In third quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Losses included in Net Income for the three and nine months ended September 30, 2010 were nil and $1 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and nine months ended September 30, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2009

(unaudited) *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[1][2]					
Assets	$150	$107	$5	-	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values[2]					
Volumes[3]					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/ U.S. 157	-
Net unrealized (losses)/gains in the period[4]					
Three months ended September 30, 2009	$(8)	$21	$(1)	$2	$(7)
Nine months ended September 30, 2009	$11	$(4)	$1	$4	$20
Net realized gains/(losses) in the period[4]					
Three months ended September 30, 2009	$23	$(43)	$1	$11	$(5)
Nine months ended September 30, 2009	$53	$(56)	-	$28	$(14)
Maturity dates[2]	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[5][6]					
Fair Values[1][2]					
Assets	$175	$2	-	-	$15
Liabilities	$(148)	$(22)	-	$(43)	$(50)
Notional Values[2]					
Volumes[3]					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period[4]					
Three months ended September 30, 2009	$30	$(8)	-	-	$(10)
Nine months ended September 30, 2009	$108	$(28)	-	-	$(27)
Maturity dates[2]	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.

(2) As at December 31, 2009.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million at December 31, 2009. Net realized gains on fair value hedges for the three and nine months ended September 30, 2009 were $1 million and $3 million, respectively, and were included in Interest Expense. In third quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three and nine months ended September 30, 2009 included gains of $1 million and $2 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and nine months ended September 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

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

Fair Value Hierarchy

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

Financial assets and liabilities measured at fair value as of September 30, 2010, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in third quarter 2010.

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

(1) The fair value of guarantees is included in Deferred Amounts.

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

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

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) The fair value of guarantees is included in Deferred Amounts. No amounts were recognized in Net Income for the periods presented.
(3) The total amount of net losses included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date was $1 million and $1 million for the three and nine months ended September 30, 2010, respectively.
(4) As contracts near maturity, they are transferred out of Level III and into Level II.

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

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

7. Employee Future Benefits

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

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

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

8. Commitments and Contingencies

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

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

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

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

Visit the TransCanada website at: http://www.transcanada.com.