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NewsRelease

TransCanada Reports 2010 Comparable Earnings of $1.4 Billion Increases Common Share Dividend by Five Per Cent

CALGARY, Alberta – **February 15, 2011** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for fourth quarter 2010 of $384 million or $0.55 per share. For the year ended December 31, 2010, comparable earnings were $1.4 billion or $1.97 per share.

Net income applicable to common shares for fourth quarter 2010 of $269 million or $0.39 per share includes the impact of a $127 million after-tax, one-time valuation provision recorded against the Mackenzie Gas Project. Including this provision, net income applicable to common shares for the year ended December 31, 2010 was $1.2 billion or $1.78 per share.

TransCanada's Board of Directors also declared a quarterly dividend of $0.42 per common share which equates to $1.68 per common share on an annualized basis, a five per cent increase. This is the eleventh consecutive year the Board of Directors has raised the dividend.

"TransCanada's strong comparable earnings for the fourth quarter of 2010 demonstrates the stability of our core businesses," says Russ Girling, TransCanada's president and chief executive officer.

"The Company continues to advance its unprecedented $20 billion capital program as more projects begin operations – the Cushing extension of Keystone and the Groundbirch and Bison natural gas pipelines are the latest large scale projects to be brought into service – projects that will further contribute to TransCanada's earnings and cash flow for years to come."

Girling added with the completion of the initial phase of Keystone in June 2010 and, more recently, the Cushing extension, Groundbirch and Bison, TransCanada has seen six major developments begin operating in recent months. In the fall of 2010, the Company announced completion and the start of operations of the second phase of the Kibby Wind project in Maine and the Halton Hills Generating Station in Ontario.

The capital program will continue to progress in the coming months. TransCanada's Coolidge Generating Station in Arizona is 95 per cent complete and construction of the Guadalajara Pipeline in Mexico is 70 per cent finished. Both projects are expected to begin operations in second quarter 2011.

Fourth Quarter and Year-End Highlights
(All financial figures are unaudited and in Canadian dollars unless noted otherwise)

- For fourth quarter 2010
  - Comparable earnings of $384 million or $0.55 per share
  - Comparable EBITDA of $1.0 billion
  - Funds generated from operations of $812 million
- For the year ended December 31, 2010
  - Comparable earnings of $1.4 billion or $1.97 per share
  - Comparable EBITDA of $3.9 billion
  - Funds generated from operations of $3.3 billion
- Placed into-service or completed construction on capital projects totalling approximately $8.5 billion
  - The $6.0 billion phases one and two of the Keystone oil pipeline including the Cushing extension
  - The $155 million Groundbirch pipeline became operational connecting Montney shale gas in northeast B.C., along with the US$630 million Bison pipeline which connects U.S. Rockies gas to market
  - The $800 million North Central Corridor natural gas pipeline
  - The $700 million Halton Hills Generating Station
  - The second phase of the US$350 million Kibby Wind project

Comparable earnings for fourth quarter 2010 were $384 million ($0.55 per share) compared to $328 million ($0.48 per share) in the same period in 2009. The increase was primarily due to the start-up of the Halton Hills power plant in September, increased plant availability at Bruce A, higher contribution from U.S. Power, higher return on equity on a larger rate base for the Alberta System, lower Alaska Pipeline Project development costs and lower net interest expense from the capitalization of interest related to the Company's large capital growth program. Partially offsetting these increases were lower realized power prices for Bruce B and Western Power and a reduction in natural gas storage revenues.

Net income applicable to common shares for fourth quarter 2010 was $269 million ($0.39 per share) compared to $381 million ($0.56 per share) in fourth quarter 2009. Net income in 2010 included a $127 million after-tax ($0.18 per share) valuation provision against advances to the Aboriginal Pipeline Group (APG) for the Mackenzie Gas Project (MGP) and net unrealized gains resulting from adjustments for changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net income in 2009 included a dilution gain resulting from TransCanada's reduced ownership in PipeLines LP and favourable income tax adjustments.

Comparable earnings for the year ended December 31, 2010 were $1.4 billion ($1.97 per share) compared to $1.3 billion ($2.03 per share) for the same period in 2009.

Net income applicable to common shares for the year ended December 31, 2010 was $1.2 billion ($1.78 per share) compared to $1.4 billion ($2.11 per share) in the same period last year.

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

Oil Pipelines:

- The second phase of the Keystone Pipeline System to expand nominal capacity to 591,000 Bbl/d and extend the pipeline system to Cushing, Oklahoma is now operational. The first two phases of Keystone (Wood River/Patoka, Illinois and Cushing, Oklahoma) have contracted volumes of 530,000 Bbl/d.

TransCanada's 500,000 Bbl/d U.S. Gulf Coast Expansion continues to move forward. The pipeline has binding, long-term commitments for 380,000 Bbl/d. The regulatory process conducted by the Department of State is continuing within a heightened political environment and opposition to the project has been expressed. However, the Company anticipates a decision regarding final regulatory approval for the U.S. portion of the project in mid to late 2011. Canadian regulatory approvals are already in place.

The total capital cost of the Keystone Pipeline System is expected to be approximately US$13 billion. The revised capital cost estimate reflects currency translation, higher than anticipated costs to complete the first two phases of the project and an increase in the estimated cost of completing the U.S. Gulf Coast Expansion as a result of scope changes, evolving regulatory requirements and permitting delays.

At December 31, 2010, US$7.4 billion had been invested, including US$1.4 billion related to the U.S. Gulf Coast Expansion. The remaining US$5.6 billion, US$1.2 billion of which has already been committed, is expected to be invested between now and the in-service date of the expansion, which is expected in 2013.

The U.S. Gulf Coast Expansion project 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.

Successful open seasons for both the Bakken and Cushing Marketlink Projects concluded in January 2011. Bakken Marketlink will deliver U.S. crude oil from Baker, Montana to Cushing, Oklahoma using pipeline facilities that form part of the Keystone Gulf Coast Expansion. This project has secured a total of 65,000 Bbl/d of firm, term contracts.

TransCanada has received sufficient contractual support to proceed with the Cushing Marketlink Project, which will have the ability to provide transportation of 150,000 Bbl/d of U.S. crude oil from Cushing, Oklahoma to the U.S. Gulf Coast. Combined with Bakken Marketlink, the two projects will have the pipeline capacity to transport up to 250,000 Bbl/d of U.S. crude oil to market.

Natural Gas Pipelines:

- The $155 million Groundbirch pipeline began shipping natural gas in late December 2010. Groundbirch is a 77-kilometre (km) (48-mile), 36-inch diameter natural gas pipeline that extends the Alberta System into northeast B.C. by connecting to natural gas supplies in the Montney shale gas formation. The project has firm transportation contracts rising to 1.24 billion cubic feet per day (Bcf/d) by 2014.

  The National Energy Board (NEB) approved the Horn River pipeline project in late January 2011. The $310 million project is scheduled to be operational in second quarter 2012 with commitments for contracted natural gas volumes rising to 634 million cubic feet per day (mmcf/d) by 2014.

  New requests for further natural gas transmission service continue to be received to connect gas from northwest Alberta and northeast B.C. The result is expected to be a need for additional extensions and expansions of the Alberta System.

- The US$630 million Bison natural gas pipeline commenced operations in January 2011. The 487-km (303-mile) pipeline has long-term contracts for 407 mmcf/d to deliver gas from the

Powder River Basin in Wyoming to the Northern Border pipeline system in North Dakota and on to North American markets.

- Construction of the Guadalajara pipeline is 70 per cent complete as of December 31, 2010. The US$360 million project is expected to be operational in mid 2011. At 305 km (190 miles) in length, the 24 and 30-inch diameter natural gas pipeline will have the capacity to move 500 mmcf/d from Manzanillo to Guadalajara, Mexico's second largest city.

- TransCanada filed an application with the National Energy Board in late January 2011 for approval of revised interim tolls for its Canadian Mainline effective March 1, 2011. The Company's initial interim toll application was rejected by the NEB in December 2010. The revised interim tolls are consistent with the existing 2007-2011 settlement with customers.

  The Company continues discussions with shippers and other stakeholders, working toward developing a longer term arrangement that will enhance the competitiveness of the Canadian Mainline and the Western Canadian Sedimentary Basin.

- TransCanada held two successful open seasons to transport Marcellus shale gas on the Canadian Mainline. Contracts were signed with shippers for 230,000 gigajoules per day to ship gas to Eastern Canadian markets.

- The Alaska Pipeline Project team continues to work with shippers to resolve conditions under its control that are contained in bids received as part of the project's open season. Multiple conditional bids from major industry players and others for significant volumes were submitted.

- The Mackenzie Gas Project proponents continue to pursue the required regulatory approvals for the project and the Canadian government's support of an acceptable fiscal framework. In December 2010, the NEB released a decision granting approval of the project's application for a Certificate of Public Convenience and Necessity. The approval contained 264 conditions including the requirement to file an updated cost estimate and report on the decision to construct by the end of 2013 and, further, that construction must commence by December 31, 2015.

  Nevertheless, uncertainty persists with respect to the project's ultimate commercial structure and fiscal framework as well as the timeframes under which the project will proceed and if and when the Company's advances to the APG will be repaid. Accordingly, at December 31, 2010, TransCanada recorded a valuation provision for its $146 million loan to the APG. Future amounts advanced to the APG in furtherance of the MGP will be expensed.

  TransCanada remains committed to advancing the project.

Energy:

- Construction of the 575 MW Coolidge generating station is approximately 95 per cent complete as of December 31, 2010, with commissioning approximately 80 per cent finished. The US$500 million generating station is anticipated to be in service in second quarter 2011. All of the power produced by the facility will be sold under a 20-year power purchase arrangement to the Salt River Project.

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

- Refurbishment work on Bruce Power Units 1 and 2 reached a significant milestone in December 2010 as Atomic Energy of Canada wrapped up a substantial portion of its work on Unit 2 and is on schedule to complete work on Unit 1 by second quarter 2011.

  Subject to regulatory approval, Bruce expects to load fuel into Unit 2 in second quarter 2011, synchronize to the electrical grid by the end of 2011 and begin operations in first quarter 2012. Unit 1 should see fuel load starting in third quarter 2011, first synchronization of the generator in first quarter 2012 and commercial operations are expected to begin in third quarter 2012. TransCanada's share of the total capital costs is expected to be $2.4 billion.

- On February 8, 2011 TransCanada received from TransAlta Corporation (TransAlta) notice under the Sundance A Power Purchase Arrangement (PPA) that TransAlta has determined that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored and that TransAlta therefore seeks to terminate the PPA in respect of those units. TransCanada has not received any information that would validate TransAlta's determination that the units cannot be economically restored to service.

  TransCanada has 10 business days from the date of TransAlta's notice to either agree with or dispute TransAlta's determination that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored. TransCanada will assess any information provided by TransAlta during this 10 day period. If TransCanada disputes TransAlta's determination, the issue will be resolved using the dispute resolution procedure under the terms of the PPA.

  In December 2010, the Sundance 1 and 2 generating units were withdrawn from service for testing. In January 2011, these same units were subject to a force majeure claim by TransAlta under the PPA. To date, TransCanada has received insufficient information to make an assessment of TransAlta's force majeure claim and therefore has recorded revenues under the PPA as though this event was a normal plant outage.

Corporate:

- The Board of Directors of TransCanada declared a quarterly dividend of $0.42 per share for the quarter ending March 31, 2011 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.68 per common share on an annual basis and represents a five per cent increase over the previous amount.

- 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 fourth 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 $20 billion capital program, before opening the call to questions from analysts and members of the media.

Event:
TransCanada 2010 fourth quarter financial results teleconference and webcast

Date:
Tuesday, February 15, 2011

Time:
1 p.m. mountain standard time (MST) / 3 p.m. eastern standard time (EST)

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 (EST) February 22, 2011. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 2263263#.

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

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Fourth Quarter 2010 Financial Highlights

Operating Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2010**	2009	Year end ended December 31 **2010**	2009
Revenues	**2,057**	1,986	**8,064**	8,181
Comparable EBITDA[1]	**1,005**	965	**3,941**	4,107
Net Income	**283**	387	**1,272**	1,380
Net Income Applicable to Common Shares	**269**	381	**1,227**	1,374
Comparable Earnings[1]	**384**	328	**1,361**	1,325
Cash Flows				
Funds generated from operations[1]	**812**	850	**3,331**	3,080
Decrease/(increase) in operating working capital	**22**	(217)	**(249)**	(90)
Net cash provided by operations	**834**	633	**3,082**	2,990
Capital Expenditures	**1,471**	1,474	**5,036**	5,417
Acquisitions, Net of Cash Acquired	**-**	-	**-**	902

Common Share Statistics

(unaudited)	Three months ended December 31 **2010**	2009	Year end ended December 31 **2010**	2009
Net Income per Share - Basic	**$0.39**	$0.56	**$1.78**	$2.11
Comparable Earnings per Share[1]	**$0.55**	$0.48	**$1.97**	$2.03
Dividends Declared per Share	**$0.40**	$0.38	**$1.60**	$1.52
Basic Common Shares Outstanding (millions)				
Average for the period	**695**	683	**691**	652
End of period	**696**	684	**696**	684

(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.

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 security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future financial and operational plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects, and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules (including anticipated construction and completion dates), operating and financial results, and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect 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 the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, 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 not to 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 not to 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 and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

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, write-downs of assets and investments, and certain fair value adjustments on risk management activities. The table in the Consolidated Results of Operations section of this news release 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 and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Fourth Quarter 2010 Financial Highlights table of this news release.

Consolidated Results of Operations

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

For the three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	Natural Gas Pipelines		Energy		Corporate		Total	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Comparable EBITDA[1]	**737**	745	**301**	248	**(33)**	(28)	**1,005**	965
Depreciation and amortization	**(241)**	(257)	**(103)**	(86)	**-**	-	**(344)**	(343)
Comparable EBIT[1]	**496**	488	**198**	162	**(33)**	(28)	**661**	622
Specific items:								
Valuation provision for MGP	**(146)**	-	**-**	-	**-**	-	**(146)**	-
Risk management activities	**-**	-	**22**	7	**-**	-	**22**	7
Dilution gain from reduced interest in PipeLines LP	**-**	29	**-**	-	**-**	-	**-**	29
EBIT[1]	**350**	517	**220**	169	**(33)**	(28)	**537**	658
Interest expense							**(173)**	(184)
Interest expense of joint ventures							**(15)**	(17)
Interest income and other							**61**	22
Income taxes							**(94)**	(67)
Non-controlling interests							**(33)**	(25)
Net Income							**283**	387
Preferred share dividends							**(14)**	(6)
Net Income Applicable to Common Shares							**269**	381
Specific items (net of tax, where applicable):								
Valuation provision for MGP							**127**	-
Risk management activities							**(12)**	(5)
Dilution gain from reduced interest in PipeLines LP							**-**	(18)
Income tax adjustments							**-**	(30)
Comparable Earnings[1]							**384**	328

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

(2)

For the year ended December 31 *(unaudited)*	**2010**	2009
Comparable Earnings per Share[1]	**$0.55**	$0.48
Specific items (net of tax, where applicable):		
Valuation provision for MGP	**(0.18)**	-
Risk management activities	**0.02**	0.01
Dilution gain from reduced interest in PipeLines LP	**-**	0.03
Income tax adjustments	**-**	0.04
Net Income per Share	**$0.39**	$0.56

For the year ended December 31 *(unaudited)(millions of dollars except per share amounts)*	Natural Gas Pipelines **2010**	2009	Energy **2010**	2009	Corporate **2010**	2009	Total **2010**	2009
Comparable EBITDA[1]	**2,915**	3,093	**1,125**	1,131	**(99)**	(117)	**3,941**	4,107
Depreciation and amortization	**(977)**	(1,030)	**(377)**	(347)	**-**	-	**(1,354)**	(1,377)
Comparable EBIT[1]	**1,938**	2,063	**748**	784	**(99)**	(117)	**2,587**	2,730
Specific items:								
Valuation provision for MGP	**(146)**	-	**-**	-	**-**	-	**(146)**	-
Risk management activities	**-**	-	**(8)**	1	**-**	-	**(8)**	1
Dilution gain from reduced interest in PipeLines LP	**-**	29	**-**	-	**-**	-	**-**	29
EBIT[1]	**1,792**	2,092	**740**	785	**(99)**	(117)	**2,433**	2,760
Interest expense							**(701)**	(954)
Interest expense of joint ventures							**(59)**	(64)
Interest income and other							**94**	121
Income taxes							**(380)**	(387)
Non-controlling interests							**(115)**	(96)
Net Income							**1,272**	1,380
Preferred share dividends							**(45)**	(6)
Net Income Applicable to Common Shares							**1,227**	1,374
Specific items (net of tax, where applicable):								
Valuation provision for MGP							**127**	-
Risk management activities							**7**	(1)
Dilution gain from reduced interest in PipeLines LP							**-**	(18)
Income tax adjustments							**-**	(30)
Comparable Earnings[1]							**1,361**	1,325

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

(2)

For the year ended December 31 *(unaudited)*	**2010**	2009
Comparable Earnings per Share[1]	**$1.97**	$2.03
Specific items (net of tax, where applicable):		
Valuation provision for MGP	**(0.18)**	-
Risk management activities	**(0.01)**	-
Dilution gain from reduced interest in PipeLines LP	**-**	0.03
Income tax adjustments	**-**	0.05
Net Income per Share	**$1.78**	$2.11

TransCanada's Net Income in fourth quarter 2010 was $283 million and Net Income Applicable to Common Shares was $269 million or $0.39 per share compared to $387 million and $381 million or $0.56 per share, respectively, in fourth quarter 2009.

Comparable Earnings in fourth quarter 2010 were $384 million or $0.55 per share compared to $328 million or $0.48 per share for the same period in 2009. Comparable Earnings in fourth quarter 2010 excluded a $127 million after-tax ($146 million pre-tax) valuation provision on advances to the APG for the MGP as well as net unrealized gains of $12 million after tax ($22 million pre-tax) (2009 - $5 million after tax gains ($7 million pre-tax)) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Comparable Earnings in fourth quarter 2009 also excluded $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates and an $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced ownership interest in PipeLines LP after a public offering of PipeLines LP common units in fourth quarter 2009.

Comparable Earnings increased $56 million or $0.07 per share in fourth quarter 2010 compared to the same period in 2009 and reflected the following:

- increased Comparable EBIT from Natural Gas Pipelines primarily due to lower business development costs, higher earnings from an Alberta System revenue requirement settlement, increased revenues from Northern Border and reduced depreciation expense for Great Lakes, partially offset by lower revenues from the Canadian Mainline and the Alberta System for amounts recovered on a flow-through basis;

- increased Comparable EBIT from Energy primarily due to increased power generation at Bruce A, higher capacity revenues, sales volumes and realized prices for U.S. Power and incremental earnings from the start-up of Halton Hills which went into service in September 2010, partially offset by lower Bruce B lease expense in 2009, lower realized power prices for Western Power and Bruce B, and decreased proprietary and third party storage revenues for Natural Gas Storage;

- increased Comparable EBIT loss from Corporate primarily due to higher support services and other corporate costs;

- decreased Interest Expense primarily due to increased capitalized interest relating to Keystone and other capital projects and the positive impact 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;

- increased Interest Income and Other, reflecting higher gains in fourth quarter 2010 compared to fourth quarter 2009 from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income;

- increased Income Taxes in fourth quarter 2010 due to positive income tax adjustments which reduced income taxes in fourth quarter 2009, partially offset by lower pre-tax earnings in fourth quarter 2010; and

- increased preferred share dividends recorded on preferred shares issued in 2010.

For the year ended December 31, 2010, Net Income was $1,272 million and Net Income Applicable to Common Shares was $1,227 million or $1.78 per share compared to $1,380 million and $1,374 million or $2.11 per share, respectively, in 2009.

Comparable Earnings in 2010 were $1,361 million or $1.97 per share compared to $1,325 million or $2.03 per share for 2009. Comparable Earnings in 2010 excluded the $127 million after-tax ($146 million pre-tax) valuation provision on advances to the APG for the MGP as well as net unrealized losses of $7 million after tax ($8 million pre-tax) (2009 - $1 million after-tax gains; $1 million pre-tax)) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Comparable Earnings in 2009 also excluded the $30 million of favourable income tax adjustments and the $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced interest in PipeLines LP.

Comparable Earnings increased $36 million and decreased $0.06 per share in 2010 compared to 2009. The increase in Comparable Earnings reflected:

- decreased Comparable EBIT from Natural Gas Pipelines primarily due to the negative impact in 2010 of a weaker U.S. dollar on Natural Gas Pipelines' U.S. operations, a decrease in Canadian Mainline revenues due to decreased amounts recovered on a flow-through basis, and reduced revenues for Great Lakes. These decreases were partially offset by decreased operating, maintenance and administration (OM&A) costs, reduced depreciation expense primarily for Great Lakes, increased revenue for Northern Border and higher earnings as a result of an Alberta System revenue requirement settlement;

- decreased Comparable EBIT from Energy primarily due to lower realized power prices for Western Power and Bruce B, and lower Natural Gas Storage price spreads, partially offset by higher capacity revenues at Ravenswood and incremental earnings from the start-up of Halton Hills, Portlands Energy and Kibby Wind;

- decreased Comparable EBIT loss from Corporate primarily due to lower support services and other corporate costs;

- decreased Interest Expense primarily due to an increase in capitalized interest relating to Keystone and other capital projects, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense and Canadian debt maturities, partially offset by interest expense for long-term debt issuances in 2010, and increased losses from changes in the fair value of derivatives used to manage the Company's exposure to fluctuating interest rates;

- decreased Interest Income and Other due to a higher positive impact in 2009 compared to 2010 of a weakening U.S. dollar on U.S. dollar working capital balances throughout the year;

- decreased Income Taxes due to reduced pre-tax earnings in 2010 partially offset by positive tax adjustments in 2009;

- an increase in Non-Controlling Interests due to higher PipeLines LP earnings; and

- increased preferred share dividends recorded on preferred shares issued in 2010 and third quarter 2009.

Net Income per Share and Comparable Earnings per Share in 2010 were reduced due to a six per cent increase in the average number of common shares outstanding, compared to 2009, as a result of the Company's issuance of 58.4 million common shares in second quarter 2009 and the dividend reinvestment and share purchase plan.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Natural Gas Pipelines and U.S. Energy EBIT is partially offset by U.S. dollar-denominated interest expense. The resultant net exposure is managed using derivatives, further reducing the Company's exposure to changes in U.S. exchange rates.

Results from each of the segments for fourth quarter 2010 are discussed further in the Natural Gas Pipelines, Energy and Other Income Statement Items sections of this news release.

Natural Gas Pipelines

Natural Gas Pipelines' Comparable EBIT was $496 million in fourth quarter 2010 compared to $488 million for the same period in 2009. Comparable EBIT in 2010 excluded a $146 million pre-tax valuation provision on advances to the APG for the MGP. Comparable EBIT in 2009 excluded the $29 million pre-tax dilution gain resulting from TransCanada's reduced ownership interest in PipeLines LP which occurred following public issuance of common units by PipeLines LP in fourth quarter 2009.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2010**	2009	Year ended December 31 **2010**	2009
Canadian Natural Gas Pipelines				
Canadian Mainline	**269**	282	**1,054**	1,133
Alberta System	**194**	193	**742**	728
Foothills	**33**	32	**135**	132
Other (TQM, Ventures LP)	**11**	15	**50**	59
Canadian Natural Gas Pipelines Comparable EBITDA[1]	**507**	522	**1,981**	2,052
Depreciation and amortization	**(180)**	(183)	**(715)**	(714)
Canadian Natural Gas Pipelines Comparable EBIT[1]	**327**	339	**1,266**	1,338
U.S. Natural Gas Pipelines (in U.S. dollars)				
ANR	**76**	79	**314**	300
GTN[2]	**45**	41	**171**	170
Great Lakes[3]	**26**	28	**109**	120
PipeLines LP[2][4]	**26**	23	**99**	90
Iroquois	**16**	16	**67**	68
Portland[5]	**10**	8	**22**	22
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**8**	12	**42**	52
General, administrative and support costs[6]	**(6)**	-	**(31)**	(17)
Non-controlling interests[7]	**48**	39	**173**	153
U.S. Natural Gas Pipelines Comparable EBITDA[1]	**249**	246	**966**	958
Depreciation and amortization	**(61)**	(69)	**(256)**	(276)
U.S. Natural Gas Pipelines Comparable EBIT[1]	**188**	177	**710**	682
Foreign exchange	**2**	8	**24**	105
U.S. Natural Gas Pipelines Comparable EBIT[1] (in Canadian dollars)	**190**	185	**734**	787
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[1]	**(21)**	(36)	**(62)**	(62)
Natural Gas Pipelines Comparable EBIT[1]	**496**	488	**1,938**	2,063
Summary:				
Natural Gas Pipelines Comparable EBITDA[1]	**737**	745	**2,915**	3,093
Depreciation and amortization	**(241)**	(257)	**(977)**	(1,030)
Natural Gas Pipelines Comparable EBIT[1]	**496**	488	**1,938**	2,063
Specific Items:				
Valuation provision for MGP[8]	**(146)**	-	**(146)**	-
Dilution gain from reduced interest in PipeLines LP[4][9]	**-**	29	**-**	29
Natural Gas Pipelines EBIT[1]	**350**	517	**1,792**	2,092

(1) Refer to the Non-GAAP Measures section in this news release 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) Represents the Company's 53.6 per cent direct ownership interest.
(4) Effective November 18, 2009, PipeLines LP's results reflected TransCanada's ownership interest in PipeLines LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in PipeLines LP was 42.6 per cent. From January 1, 2009 to June 30, 2009, TransCanada's ownership interest in PipeLines LP was 32.1 per cent.
(5) Portland's results reflect TransCanada's 61.7 per cent ownership interest.
(6) Represents general, administrative and support costs associated with certain of the Company's pipelines, including $7 million and $17 million for the three months and year ended December 31, 2010, respectively, for the start-up of Keystone.
(7) Non-controlling interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TransCanada.
(8) The Company has recorded a valuation provision of $146 million for its advances to the APG for the MGP, which is discussed further below.

(9) As a result of PipeLines LP issuing common units to the public in fourth quarter 2009, the Company's ownership interest in PipeLines LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of $29 million was realized.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited) *(millions of dollars)*	Three months ended December 31 **2010**	2009	Year ended December 31 **2010**	2009
Canadian Mainline	**71**	72	**267**	273
Alberta System	**53**	45	**198**	168
Foothills	**7**	5	**27**	23

Canadian Natural Gas Pipelines

Canadian Mainline's net income in fourth quarter 2010 decreased $1 million to $71 million from $72 million for the same period in 2009. Net income in fourth quarter 2010 reflected a lower rate of return on common equity (ROE) of 8.52 per cent compared to 8.57 per cent in 2009 on 40 per cent deemed common equity and a lower average investment base, partially offset by higher incentive earnings.

Canadian Mainline's Comparable EBITDA in fourth quarter 2010 of $269 million decreased $13 million from $282 million compared to the same period 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 of $53 million in fourth quarter 2010 increased $8 million compared to the same period in 2009. Net income in fourth quarter 2010 reflected an ROE of 9.70 per cent on 40 per cent deemed common equity and a higher average investment base, earned under the Alberta System's 2010 – 2012 Revenue Requirement Settlement, partially offset by lower incentive earnings.

The Alberta System's Comparable EBITDA was $194 million in fourth quarter 2010 compared to $193 million for the same period in 2009. Comparable EBITDA in fourth quarter 2010 reflected an ROE of 9.70 per cent on 40 per cent deemed common equity and an increased average investment base, earned under the Alberta System's 2010 – 2012 Revenue Requirement Settlement, partially offset by lower revenues as a result of lower financial charges which are recovered on a flow-through basis and lower incentive earnings compared to 2009.

Net income and Comparable EBITDA from Foothills in fourth quarter 2010 increased $2 million and $1 million, respectively, compared to 2009. These increases were primarily due to a Foothills 2010 agreement, which established an ROE of 9.70 per cent on deemed common equity of 40 per cent for the years 2010 to 2012. Results in 2009 were based on the NEB ROE formula of 8.57 per cent on deemed common equity of 36 per cent.

Comparable EBITDA from Other Canadian Natural Gas Pipelines was $11 million in fourth quarter 2010 compared to $15 million for the same period in 2009. The decrease in fourth quarter 2010 was primarily due to an adjustment to TQM's cost of capital in 2009.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA in fourth quarter 2010 was US$76 million compared to US$79 million for the same period in 2009. The decrease was primarily due to lower transportation sales and storage revenues as higher regional storage inventories and marginal supply from the U. S. Gulf Coast negatively affected transportation rates and demand for natural gas.

GTN's Comparable EBITDA in fourth quarter 2010 was US$45 million compared to US$41 million for the same period in 2009. The increase in fourth quarter 2010 was primarily due to incremental proceeds accrued in 2010 relating to the 2005 bankruptcy distributions from Calpine and lower OM&A costs, partially offset by the write-off in 2010 of costs related to an unsuccessful information systems project.

Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines in fourth quarter 2010 was US$128 million compared to US$126 million for the same period in 2009. The increase was primarily due to the positive impact Northern Border's higher revenues had on PipeLines LP's earnings, partially offset by lower revenues from Great Lakes. U.S. Natural Gas Pipelines was also negatively affected by higher general, administrative and support costs primarily related to the start-up of Keystone.

Depreciation

Natural Gas Pipelines' depreciation decreased $16 million in fourth quarter 2010 compared to the same period in 2009 primarily due to Great Lakes' lower depreciation rate per its rate settlement and the impact of a weaker U.S. dollar.

Business Development

Natural Gas Pipelines' Business Development Comparable EBITDA losses decreased $15 million in fourth quarter 2010 compared to the same period in 2009 primarily due to decreased business development costs related to the Alaska Pipeline Project. The State of Alaska reimbursed 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. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TransCanada's joint venture partner in developing the Alaska Pipeline Project.

Operating Statistics

Year ended December 31 *(unaudited)*	Canadian Mainline(1) 2010	Canadian Mainline(1) 2009	Alberta System(2) 2010	Alberta System(2) 2009	Foothills 2010	Foothills 2009	ANR(3) 2010	ANR(3) 2009	GTN(3) 2010	GTN(3) 2009
Average investment base (millions of dollars)	**6,466**	6,531	**4,989**	4,756	**655**	705	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**1,666**	2,030	**3,447**	3,538	**1,446**	1,205	**1,589**	1,575	**802**	797
Average per day	**4.6**	5.6	**9.4**	9.7	**4.0**	3.3	**4.4**	4.3	**2.2**	2.2

(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 year ended December 31, 2010 were 1,228 billion cubic feet (Bcf) (2009 – 1,579 Bcf); average per day was 3.4 Bcf (2009 – 4.3 Bcf).

(2) Field receipt volumes for the Alberta System for the year ended December 31, 2010 were 3,471 Bcf (2009 – 3,550 Bcf); average per day was 9.5 Bcf (2009 – 9.7 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.

Energy

Energy's Comparable EBIT was $198 million in fourth quarter 2010 compared to $162 million for the same period in 2009. Comparable EBIT in fourth quarter 2010 and 2009 excluded net unrealized pre-tax gains of $22 million and $7 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. TransCanada manages its proprietary Natural Gas Storage business 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. Fair value adjustments are recorded each period on proprietary natural gas inventory in storage and on the forward contracts, however, these adjustments are not representative of the amounts that will be realized on settlement. U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers and manages exposure to fluctuations in spot prices on these power sales either with the purchase of power or the purchase of fuel to generate power from its assets, effectively locking in positive margins. These Natural Gas Storage and U.S. Power contracts provide effective economic hedges which effectively lock in a margin but do not meet the specific criteria required for hedge accounting treatment and, therefore, are recorded at their fair value based on forward market prices for the contracted month of delivery. These forwards are excluded in determining Comparable Earnings as their fair value is not representative of amounts that will be realized on settlement.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended December 31		Year ended December 31	
	2010	2009	**2010**	2009
Canadian Power				
Western Power	**48**	61	**220**	279
Eastern Power[1]	**77**	56	**231**	220
Bruce Power	**99**	70	**298**	352
General, administrative and support costs	**(9)**	(11)	**(38)**	(39)
Canadian Power Comparable EBITDA[2]	**215**	176	**711**	812
Depreciation and amortization	**(63)**	(59)	**(242)**	(227)
Canadian Power Comparable EBIT[2]	**152**	117	**469**	585
U.S. Power (in U.S. dollars)				
Northeast Power[3]	**67**	38	**335**	210
General, administrative and support costs	**(8)**	(10)	**(32)**	(40)
U.S. Power Comparable EBITDA[2]	**59**	28	**303**	170
Depreciation and amortization	**(36)**	(28)	**(116)**	(92)
U.S. Power Comparable EBIT[2]	**23**	-	**187**	78
Foreign exchange	**1**	-	**7**	8
U.S. Power Comparable EBIT[2] (in Canadian dollars)	**24**	-	**194**	86
Natural Gas Storage				
Alberta Storage	**39**	51	**140**	173
General, administrative and support costs	**(2)**	(2)	**(8)**	(9)
Natural Gas Storage Comparable EBITDA[2]	**37**	49	**132**	164
Depreciation and amortization	**(4)**	2	**(15)**	(14)
Natural Gas Storage Comparable EBIT[2]	**33**	51	**117**	150
Business Development Comparable EBITDA and EBIT[2]	**(11)**	(6)	**(32)**	(37)
Energy Comparable EBIT[2]	**198**	162	**748**	784
Summary:				
Energy Comparable EBITDA[2]	**301**	248	**1,125**	1,131
Depreciation and amortization	**(103)**	(86)	**(377)**	(347)
Energy Comparable EBIT[2]	**198**	162	**748**	784
Specific Items:				
Risk management activities	**22**	7	**(8)**	1
Energy EBIT[2]	**220**	169	**740**	785

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

Canadian Power

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

(unaudited) *(millions of dollars)*	Three months ended December 31 **2010**	2009	Year ended December 31 **2010**	2009
Revenues				
Western power	**180**	203	**714**	788
Eastern power	**113**	72	**330**	281
Other(3)	**20**	25	**84**	86
	313	300	**1,128**	1,155
Commodity Purchases Resold				
Western power	**(117)**	(124)	**(431)**	(451)
Other(3)(4)	**(2)**	(7)	**(26)**	(26)
	(119)	(131)	**(457)**	(477)
Plant operating costs and other	**(69)**	(52)	**(220)**	(179)
General, administrative and support costs	**(9)**	(11)	**(38)**	(39)
Comparable EBITDA(1)	**116**	106	**413**	460
Depreciation and amortization	**(39)**	(36)	**(140)**	(138)
Comparable EBIT(1)	**77**	70	**273**	322

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(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 December 31 **2010**	2009	Year ended December 31 **2010**	2009
Sales Volumes (GWh)				
Supply				
Generation				
Western Power	**622**	616	**2,373**	2,334
Eastern Power	**874**	469	**2,359**	1,550
Purchased				
Sundance A & B and Sheerness PPAs	**3,030**	2,878	**10,785**	10,603
Other purchases	**118**	109	**429**	529
	4,644	4,072	**15,946**	15,016
Sales				
Contracted				
Western Power	**2,843**	2,780	**10,211**	9,944
Eastern Power	**875**	471	**2,375**	1,588
Spot				
Western Power	**926**	821	**3,360**	3,484
	4,644	4,072	**15,946**	15,016
Plant Availability(2)				
Western Power(3)	**96%**	99%	**95%**	93%
Eastern Power(4)	**92%**	96%	**94%**	97%

(1) Includes Halton Hills and Portlands Energy effective September 2010 and April 2009, respectively.
(2) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(3) Excludes facilities that provide power to TransCanada under PPAs.
(4) Bécancour has been excluded from the availability calculation as power generation has been suspended since 2008.

Western Power's Comparable EBITDA of $48 million and Power Revenues of $180 million in fourth quarter 2010 decreased $13 million and $23 million, respectively, compared to the same period in 2009, primarily due to lower overall realized power prices. Contracted prices in fourth quarter 2010 contributed positive margins compared to margins realized under spot prices, however, contracted prices were lower than in fourth quarter 2009 due to the continued impact of the North American economic downturn.

Eastern Power's Comparable EBITDA of $77 million and Power Revenues of $113 million in fourth quarter 2010 increased $21 million and $41 million, respectively, compared to the same period in 2009 primarily due to incremental earnings from Halton Hills, which went into service under a 20 year power purchase arrangement (PPA) in September 2010.

Plant Operating Costs and Other of $69 million in fourth quarter 2010, which includes fuel gas consumed in power generation, increased $17 million compared to the same period in 2009 primarily due to incremental fuel consumed at Halton Hills.

Approximately 75 per cent of Western Power sales volumes were sold under contract in fourth quarter 2010, compared to 77 per cent in fourth quarter 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at December 31, 2010, Western Power had entered into fixed-price power sales contracts to sell approximately 7,400 gigawatt hours (GWh) for 2011 and 6,300 GWh for 2012.

In fourth 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 2011 and 2012.

Bruce Power Results

(TransCanada's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended December 31 **2010**	 2009	Year ended December 31 **2010**	 2009
Revenues[2]	**228**	198	**862**	883
Operating Expenses	**(129)**	(128)	**(564)**	(531)
Comparable EBITDA[1]	**99**	70	**298**	352
Bruce A Comparable EBITDA[1]	**33**	(29)	**91**	48
Bruce B Comparable EBITDA[1]	**66**	99	**207**	304
Comparable EBITDA[1]	**99**	70	**298**	352
Depreciation and amortization	**(24)**	(23)	**(102)**	(89)
Comparable EBIT[1]	**75**	47	**196**	263
Bruce Power – Other Information				
Plant availability[3]				
Bruce A	**94%**	47%	**81%**	78%
Bruce B	**91%**	95%	**91%**	91%
Combined Bruce Power	**92%**	80%	**88%**	87%
Planned outage days				
Bruce A	**-**	10	**60**	56
Bruce B	**16**	-	**70**	45
Unplanned outage days				
Bruce A	**9**	74	**64**	82
Bruce B	**-**	3	**34**	47
Sales volumes (GWh)				
Bruce A	**1,470**	737	**5,026**	4,894
Bruce B	**2,082**	2,016	**8,184**	7,767
	3,552	2,753	**13,210**	12,661
Results per MWh				
Bruce A power revenues	**$65**	$64	**$65**	$64
Bruce B power revenues[4]	**$60**	$62	**$58**	$64
Combined Bruce Power revenues	**$61**	$62	**$60**	$64
Percentage of Bruce B output sold to spot market[5]	**93%**	46%	**82%**	43%

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Revenues include Bruce A's fuel cost recoveries of $8 million and $29 million for fourth quarter and the year ended December 31, 2010, respectively (2009 – $6 million and $34 million, respectively). Revenues also include Bruce B's unrealized losses of $1 million and $6 million as a result of changes in the fair value of held-for-trading derivatives for fourth quarter and the year ended December 31, 2010, respectively (2009 – gains of $1 million and $5 million, respectively).
(3) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(4) Includes revenues received under the floor price mechanism, from contract settlements and deemed generation, and the associated volumes.
(5) 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 $29 million to $99 million in fourth quarter 2010 compared to $70 million in fourth quarter 2009.

TransCanada's proportionate share of Bruce A's Comparable EBITDA increased $62 million to $33 million in fourth quarter 2010 compared to losses of $29 million in fourth quarter 2009 as a result of higher volumes and lower operating expenses due to decreased outage days. Bruce A's plant availability in fourth quarter 2010 was 94 per cent with nine outage days compared to an availability of 47 per cent and 84 outage days for the same period in 2009.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $33 million to $66 million in fourth quarter 2010 compared to $99 million in fourth quarter 2009 primarily due to higher lease expenses and lower realized prices resulting from the expiry of fixed-price contracts at higher prices. Provisions in a lease agreement with Ontario Power Generation allowed for a reduction in the 2009 annual lease expense as the annual average Ontario spot price for electricity was less than $30 per megawatt hour (MWh). The Ontario annual average spot price was $36.25 per MWh in 2010 compared to $29.52 per MWh in 2009 and therefore resulted in no similar reduction in lease expense in 2010. Bruce B's volumes increased in fourth quarter 2010 compared to the same period in 2009 as a result of fewer surplus baseload generation derates in 2010 as required by the Independent Electricity System Operator, partially offset by lower plant availability. Bruce B's plant availability in fourth quarter 2010 was 91 per cent with 16 outage days compared to an availability of 95 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. In both 2010 and 2009, no amounts recorded in revenues were subject to repayment.

Under a contract with the OPA, all output from Bruce A in fourth 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 fourth quarter 2009. All output from the Bruce B units was subject to a floor price of $48.96 per MWh in fourth quarter 2010 and $48.76 per MWh in fourth quarter 2009. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

Bruce B enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price of $60 per MWh in fourth quarter 2010 reflected revenues recognized from both the floor price mechanism and contract sales, and decreased from $62 per MWh in fourth quarter 2009 due to higher priced contracts expiring since that time. The majority of the higher-priced contracts have expired at the end of 2010 which is expected to result in a further reduction in realized prices at Bruce B for future periods. At December 31, 2010, Bruce B had sold forward approximately 500 GWh and 700 GWh, representing TransCanada's proportionate share, for 2011 and 2012, respectively.

The overall plant availability percentage in 2011 is expected to be in the mid 80s for the two operating Bruce A units and in the high 80s for the four Bruce B units. Bruce A expects an outage of approximately one week on Unit 3 in July 2011 and, following approval from the Canadian Nuclear Safety Commission, the West Shift Plus outage of approximately six months is scheduled to commence in early November 2011 on Bruce A Unit 3. The West Shift Plus outage is a key part of the life extension strategy for Bruce A Unit 3, and is an extension of the West Shift program which was successfully executed in 2009. A maintenance outage of approximately three weeks commenced February 1, 2011 on Bruce B Unit 8 and outages of approximately seven weeks each are scheduled to begin in mid-April 2011 for Bruce B Unit 7 and mid-October 2011 for Bruce B Unit 5, respectively.

As at December 31, 2010, Bruce A had incurred approximately $4.0 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.3 billion for the refurbishment of Units 3 and 4.

U.S. Power

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

(unaudited) *(millions of U.S. dollars)*	Three months ended December 31 **2010**	2009	Year ended December 31 **2010**	2009
Revenues				
Power[3]	**238**	161	**1,090**	742
Capacity	**51**	39	**231**	169
Other[3][4]	**24**	24	**78**	79
	313	224	**1,399**	990
Commodity purchases resold[3]	**(123)**	(82)	**(543)**	(309)
Plant operating costs and other[4]	**(123)**	(104)	**(521)**	(471)
General, administrative and support costs	**(8)**	(10)	**(32)**	(40)
Comparable EBITDA[1]	**59**	28	**303**	170
Depreciation and amortization	**(36)**	(28)	**(116)**	(92)
Comparable EBIT[1]	**23**	-	**187**	78

(1) Refer to the Non-GAAP Measures section of this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes phase one and two of Kibby Wind effective October 2009 and October 2010, respectively.
(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 December 31 **2010**	2009	Year ended December 31 **2010**	2009
Sales Volumes (GWh)				
Supply				
Generation	**1,672**	1,400	**6,755**	5,993
Purchased	**1,838**	1,657	**8,899**	5,310
	3,510	3,057	**15,654**	11,303
Sales				
Contracted	**3,472**	2,999	**14,485**	10,205
Spot	**38**	58	**1,169**	1,098
	3,510	3,057	**15,654**	11,303
Plant Availability[2][3]	**70%**	81%	**86%**	79%

(1) Includes phase one and two of Kibby Wind as of October 2009 and October 2010, respectively.
(2) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(3) Plant availability decreased in the three months ended December 31, 2010 due to the impact of a planned outage at Ravenswood.

U.S. Power's Comparable EBITDA in fourth quarter 2010 of US$59 million increased US$31 million compared to the same period in 2009 primarily due to increased capacity revenues, higher realized prices, and higher volumes of power sold.

U.S. Power's Power Revenues in fourth quarter 2010 of US$238 million increased from US$161 million in the same period in 2009 primarily due to higher realized power prices and higher volumes of power sold. Capacity Revenues increased in fourth quarter 2010 compared to fourth quarter 2009, 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 increase in Capacity Revenues was partially offset by the impact of the Unit 30 outage which occurred from September 2008 to May 2009.

Commodity Purchases Resold of US$123 million in fourth quarter 2010 increased from US$82 million in the same period in 2009 primarily due to higher power prices per MWh purchased in fourth quarter 2010 and an increase in the quantity of power purchased for resale under power sales commitments to wholesale, commercial and industrial customers in New England.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, in fourth quarter 2010 of US$123 million increased US$19 million over the same period in 2009 primarily due to increased fuel costs as a result of higher fuel prices and increased generation.

In fourth quarter 2010, 99 per cent of power sales volumes were sold under contract compared to 98 per cent for the same period in 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at December 31, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 11,400 GWh for 2011 and 6,600 GWh for 2012, 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.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New York and New England markets. To manage exposure to fluctuations in spot prices, power sales are hedged with either the purchase of power or the purchase of fuel to generate power from its assets, effectively locking in positive margins.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA in fourth quarter 2010 was $37 million compared to $49 million for the same period in 2009. The decrease in Comparable EBITDA in fourth quarter 2010 was primarily due to decreased proprietary natural gas and third party storage revenues as a result of lower realized natural gas price spreads. Depreciation and amortization increased $6 million in fourth quarter 2010 compared to the same period in 2009 primarily due to a change in useful life assumption on certain assets recorded in fourth quarter 2009.

Business Development

Business Development Comparable EBITDA losses in fourth quarter 2010 increased $5 million compared to the same period in 2009 primarily due to the timing of expenses on certain key projects.

Other Income Statement Items

Interest Expense

(unaudited) *(millions of dollars)*	Three months ended December 31 **2010**	 2009	Year ended December 31 **2010**	 2009
Interest on long-term debt[(1)]				
Canadian dollar-denominated	**126**	135	**514**	548
U.S. dollar-denominated	**183**	159	**680**	645
Foreign exchange	**2**	10	**20**	92
	311	304	**1,214**	1,285
Other interest and amortization	**12**	8	**74**	27
Capitalized interest	**(150)**	(128)	**(587)**	(358)
	173	184	**701**	954

(1) Includes interest on Junior Subordinated Notes.

Interest Expense in fourth quarter 2010 decreased $11 million to $173 million from $184 million in fourth quarter 2009. The decrease reflected increased capitalized interest relating to the Company's capital growth program in 2010, primarily due to Keystone construction, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest and Canadian dollar-denominated debt maturities in 2009 and 2010. These decreases were partially offset by incremental interest expense on the new debt issues of US$1.25 billion in June 2010 and US$1.0 billion in September 2010.

Interest Income and Other in fourth quarter 2010 increased $39 million to $61 million from $22 million in fourth quarter 2009. The increase reflected higher gains in 2010 compared to 2009 from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income Taxes were $94 million in fourth quarter 2010 compared to $67 million for the same period in 2009. The increase was primarily due to positive income tax adjustments which reduced income taxes in 2009, including $30 million of favourable adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, partially offset by lower pre-tax earnings in 2010.

Consolidated Income

(unaudited) (millions of dollars except per share amounts)	Three months ended December 31 **2010**	 2009	Year ended December 31 **2010**	 2009
Revenues	**2,057**	1,986	**8,064**	8,181
Operating and Other Expenses				
Plant operating costs and other	**786**	770	**3,114**	3,213
Commodity purchases resold	**244**	215	**1,017**	831
Depreciation and amortization	**344**	343	**1,354**	1,377
Valuation provision for MGP	**146**	-	**146**	-
	1,520	1,328	**5,631**	5,421
Financial Charges/(Income)				
Interest expense	**173**	184	**701**	954
Interest expense of joint ventures	**15**	17	**59**	64
Interest income and other	**(61)**	(22)	**(94)**	(121)
	127	179	**666**	897
Income before Income Taxes and Non-Controlling Interests	**410**	479	**1,767**	1,863
Income Taxes Expense/(Recovery)				
Current	**26**	(73)	**(141)**	30
Future	**68**	140	**521**	357
	94	67	**380**	387
Non-Controlling Interests				
Non-controlling interest in PipeLines LP	**23**	15	**87**	66
Preferred share dividends of subsidiary	**5**	5	**22**	22
Non-controlling interest in Portland	**5**	5	**6**	8
	33	25	**115**	96
Net Income	**283**	387	**1,272**	1,380
Preferred Share Dividends	**14**	6	**45**	6
Net Income Applicable to Common Shares	**269**	381	**1,227**	1,374
Net Income per Common Share				
Basic	**$0.39**	$0.56	**$1.78**	$2.11
Diluted	**$0.39**	$0.56	**$1.77**	$2.11
Average Shares Outstanding – Basic (millions)	**695**	683	**691**	652
Average Shares Outstanding – Diluted (millions)	**696**	684	**692**	653

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended December 31 **2010**	2009	Year ended December 31 **2010**	2009
Cash Generated From Operations				
Net income	**283**	387	**1,272**	1,380
Depreciation and amortization	**344**	343	**1,354**	1,377
Future income taxes	**68**	140	**521**	357
Non-controlling interests	**33**	25	**115**	96
Valuation provision for MGP	**146**	-	**146**	-
Employee future benefits funding in excess of expense	**(33)**	(32)	**(69)**	(111)
Other	**(29)**	(13)	**(8)**	(19)
	812	850	**3,331**	3,080
Decrease/(increase) in operating working capital	**22**	(217)	**(249)**	(90)
Net cash provided by operations	**834**	633	**3,082**	2,990
Investing Activities				
Capital expenditures	**(1,471)**	(1,474)	**(5,036)**	(5,417)
Deferred amounts and other	**46**	(300)	**(384)**	(594)
Acquisitions, net of cash acquired	**-**	-	**-**	(902)
Net cash used in investing activities	**(1,425)**	(1,774)	**(5,420)**	(6,913)
Financing Activities				
Dividends on common and preferred shares	**(187)**	(193)	**(754)**	(728)
Distributions paid to non-controlling interests	**(29)**	(24)	**(112)**	(100)
Notes payable issued/(repaid), net	**527**	363	**474**	(244)
Long-term debt issued, net of issue costs	**34**	-	**2,371**	3,267
Reduction of long-term debt	**(65)**	(496)	**(494)**	(1,005)
Long-term debt of joint ventures issued	**13**	25	**177**	226
Reduction of long-term debt of joint ventures	**(22)**	(138)	**(254)**	(246)
Common shares issued, net of issue costs	**6**	15	**26**	1,820
Preferred shares issued, net of issue costs	**-**	-	**679**	539
Partnership units of subsidiary issued, net of issue costs	**-**	193	**-**	193
Net cash provided by/(used in) financing activities	**277**	(255)	**2,113**	3,722
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(16)**	(13)	**(8)**	(110)
Decrease in Cash and Cash Equivalents	**(330)**	(1,409)	**(233)**	(311)
Cash and Cash Equivalents				
Beginning of period	**1,094**	2,406	**997**	1,308
Cash and Cash Equivalents				
End of period	**764**	997	**764**	997

Consolidated Balance Sheet

December 31 *(unaudited)/(millions of dollars)*	**2010**	2009
ASSETS		
Current Assets		
Cash and cash equivalents	**764**	997
Accounts receivable	**1,271**	966
Inventories	**425**	511
Other	**777**	701
	3,237	3,175
Plant, Property and Equipment	**36,244**	32,879
Goodwill	**3,570**	3,763
Regulatory Assets	**1,512**	1,524
Intangibles and Other Assets	**2,026**	2,500
	46,589	43,841
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**2,092**	1,687
Accounts payable	**2,243**	2,195
Accrued interest	**367**	377
Current portion of long-term debt	**894**	478
Current portion of long-term debt of joint ventures	**65**	212
	5,661	4,949
Regulatory Liabilities	**314**	385
Deferred Amounts	**694**	743
Future Income Taxes	**3,222**	2,856
Long-Term Debt	**17,028**	16,186
Long-Term Debt of Joint Ventures	**801**	753
Junior Subordinated Notes	**985**	1,036
	28,705	26,908
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**686**	705
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland	**82**	80
	1,157	1,174
Shareholders' Equity	**16,727**	15,759
	46,589	43,841

Segmented Information

Three months ended December 31 (unaudited)(millions of dollars)	Natural Gas Pipelines 2010	Natural Gas Pipelines 2009	Energy[1] 2010	Energy[1] 2009	Corporate 2010	Corporate 2009	Total 2010	Total 2009
Revenues	**1,103**	1,171	**954**	815	**-**	-	**2,057**	1,986
Plant operating costs and other[2]	**(366)**	(397)	**(387)**	(345)	**(33)**	(28)	**(786)**	(770)
Commodity purchases resold	**-**	-	**(244)**	(215)	**-**	-	**(244)**	(215)
Depreciation and amortization	**(241)**	(257)	**(103)**	(86)	**-**	-	**(344)**	(343)
Valuation provision for MGP	**(146)**	-	**-**	-	**-**	-	**(146)**	-
	350	517	**220**	169	**(33)**	(28)	**537**	658
Interest expense							**(173)**	(184)
Interest expense of joint ventures							**(15)**	(17)
Interest income and other							**61**	22
Income taxes							**(94)**	(67)
Non-controlling interests							**(33)**	(25)
Net Income							**283**	387
Preferred share dividends							**(14)**	(6)
Net Income Applicable to Common Shares							**269**	381

Year ended December 31 (unaudited)(millions of dollars)	Natural Gas Pipelines 2010	Natural Gas Pipelines 2009	Energy[1] 2010	Energy[1] 2009	Corporate 2010	Corporate 2009	Total 2010	Total 2009
Revenues	**4,373**	4,729	**3,691**	3,452	**-**	-	**8,064**	8,181
Plant operating costs and other[2]	**(1,458)**	(1,607)	**(1,557)**	(1,489)	**(99)**	(117)	**(3,114)**	(3,213)
Commodity purchases resold	**-**	-	**(1,017)**	(831)	**-**	-	**(1,017)**	(831)
Depreciation and amortization	**(977)**	(1,030)	**(377)**	(347)	**-**	-	**(1,354)**	(1,377)
Valuation provision for MGP	**(146)**	-	**-**	-	**-**	-	**(146)**	-
	1,792	2,092	**740**	785	**(99)**	(117)	**2,433**	2,760
Interest expense							**(701)**	(954)
Interest expense of joint ventures							**(59)**	(64)
Interest income and other							**94**	121
Income taxes							**(380)**	(387)
Non-controlling interests							**(115)**	(96)
Net Income							**1,272**	1,380
Preferred share dividends							**(45)**	(6)
Net Income Applicable to Common Shares							**1,227**	1,374

(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.

(2) In 2010, Natural Gas Pipelines included $7 million and $17 million for the three months and year ended December 31, 2010, respectively, of general, administrative and support costs for the start-up of Keystone.