NewsRelease

TransCanada
In business to deliver

TransCanada Reports 2011 Comparable Earnings of $1.6 Billion Increases Common Share Dividend by Five Per Cent

CALGARY, Alberta – **February 14, 2012** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for fourth quarter 2011 of $366 million or $0.52 per share. For the year ended December 31, 2011, comparable earnings were $1.6 billion or $2.23 per share. Net income attributable to common shares for fourth quarter 2011 was $375 million or $0.53 per share, and for the year ended December 31, 2011, $1.5 billion or $2.18 per share.

TransCanada's Board of Directors also declared a quarterly dividend of $0.44 per common share for the quarter ending March 31, 2012, equivalent to $1.76 per common share on an annualized basis, an increase of five per cent. This is the twelfth consecutive year the Board of Directors has raised the dividend.

"TransCanada experienced a strong 2011 driven by incremental earnings from $10 billion of new assets placed into service since mid-2010, and the Company's existing diverse and high-quality energy infrastructure portfolio," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings for 2011 were $2.23 per share, a 13 per cent increase over 2010.

"Having made substantial progress on our unprecedented capital program, these new operating assets are doing what they were designed to do – producing sustainable earnings and cash flow for our shareholders while delivering energy safely and reliably to customers across North America," added Girling.

The Company is positioned to complete another $12 billion of new projects that are expected to come into service between now and early 2015 including the Bruce Power restart program in Ontario, additional extensions and expansions of the Alberta System, the final phase of the Cartier Wind power project in Québec, nine Ontario solar projects and the Keystone Gulf Coast Expansion (Keystone XL). TransCanada expects these assets to generate significant, sustained earnings and cash flow growth and deliver superior returns to our shareholders.

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

- For fourth quarter 2011
    - Comparable earnings of $366 million or $0.52 per share
    - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.2 billion
    - Net income attributable to common shares of $375 million or $0.53 per share
    - Funds generated from operations of $881 million
- For the year ended December 31, 2011
    - Comparable earnings of $1.6 billion or $2.23 per share
    - Comparable EBITDA of $4.8 billion
    - Net income attributable to common shares of $1.5 billion or $2.18 per share
    - Funds generated from operations of $3.7 billion
- Announced an increase in the quarterly dividend per common share of five per cent to $0.44 for the quarter ending March 31, 2012

- Began generating incremental EBITDA from $10 billion of capital projects placed into service since mid-2010, adding significant contracted earnings and cash flow. Some 2011 examples include:
  - The US$630 million Bison natural gas pipeline commenced operations in January
  - The Wood River/Patoka, Illinois section and the Cushing extension of the Keystone oil pipeline, costing $6 billion, began recognizing EBITDA in February
  - The US$500 million Coolidge Generating Station commenced commercial operations in May
  - The US$360 million Guadalajara natural gas pipeline was completed in June
  - The Montagne-Sèche and phase one of the Gros-Morne wind farms, capable of producing 159 megawatts (MW) of renewable energy, were completed in November
- Agreed to purchase nine Ontario solar projects for approximately $470 million. The projects have a combined capacity of 86 MW and are underpinned by 20-year power purchase agreements (PPA) with the Ontario Power Authority (OPA).
- Advanced commercial arrangements in the Oil Pipelines business
  - Secured additional long-term, binding commitments in support of the Keystone XL pipeline. The Keystone pipeline system has secured firm, long term contracts for more than 1.1 million barrels per day (bbl/d) for an average term of approximately 18 years.
  - Announced plans to build the Houston Lateral and increase the capacity of Keystone XL to 830,000 bbl/d at a cost of US$600 million. The expansion will increase the capacity on the entire Keystone pipeline system to 1.4 million bbl/d.

Comparable earnings for fourth quarter 2011 were $366 million or $0.52 per share compared to $384 million or $0.55 per share for the same period in 2010. Incremental earnings from Keystone and other recently commissioned assets, combined with higher power prices in Alberta, were more than offset by lower contributions from Bruce Power related to planned plant outages, higher interest expense as a result of lower capitalized interest, reduced earnings from U.S. Power, and net realized losses in 2011 compared to gains in 2010 from derivatives used to manage foreign exchange rate fluctuations.

Comparable earnings for the year ended December 31, 2011 were $1.565 billion or $2.23 per share compared to $1.361 billion or $1.97 per share in 2010. The increase was primarily due to higher power prices in Alberta and incremental earnings from recently commissioned assets. Partially offsetting these increases were higher interest expenses and lower contributions from Bruce Power, Natural Gas Storage and U.S. Power.

Net income attributable to common shares for fourth quarter 2011 was $375 million or $0.53 per share compared to $269 million or $0.39 per share in fourth quarter 2010. Net income attributable to common shares for the year ended December 31, 2011 was $1.527 billion or $2.18 per share compared to $1.227 billion or $1.78 per share in 2010. Net income for the fourth quarter and year ended December 31, 2010 included a $127 million after-tax ($0.18 per share) valuation provision against advances to the Aboriginal Pipeline Group for the Mackenzie Gas Project and net unrealized gains resulting from changes in the fair value of certain risk management activities.

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

Oil Pipelines:

- In November 2011, the U.S. Department of State (DOS) determined it necessary to identify and assess alternative routes for Keystone XL that would avoid the Sandhills region in Nebraska in order to move forward with a decision on the Presidential Permit. The DOS indicated it expected this process to take until first quarter 2013.

TransCanada continues to work with the State of Nebraska to determine the best route that avoids the Sandhills region in Nebraska.

- In December 2011, TransCanada concluded a successful open season for its Houston Lateral project and signed long-term contracts to transport crude oil from Hardisty, Alberta to Houston, Texas. The US$600 million project would increase the capacity of Keystone XL to 830,000 bbl/d and involve the construction of an 80-Kilometre (km) (50-mile) pipeline extension from the proposed Keystone XL expansion.

  The Houston Lateral is expected to more than double the U.S. Gulf Coast refining market capacity directly accessible from Keystone to over four million bbl/d and is expected to be in service by early 2015.

  The capital cost of Keystone XL, including the Houston Lateral, is estimated to be US$7.6 billion, with US$2.4 billion having been invested as of December 31, 2011. The remainder is expected to be spent between now and the in-service date of the expansion, which is expected by early 2015.

- In fourth quarter 2011, TransCanada secured additional contractual support for the Cushing Marketlink project, which would transport crude oil from Cushing to Port Arthur and Houston, Texas. The US$50 million project would use a portion of the Keystone XL facilities, including the Houston Lateral. Cushing Marketlink is expected to begin shipping crude oil in early 2015.

- TransCanada is pursuing opportunities to transport growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to major U.S. refining markets. In 2010, the Company secured firm, five-year shipper contracts totalling 65,000 bbl/d for its proposed US$140 million Bakken Marketlink project, which would transport U.S. crude oil from Baker, Montana to Cushing, Oklahoma on facilities that form part of Keystone XL. This project is expected to be operational early in 2015.

- On December 23, 2011, the *Temporary Payroll Tax Cut Continuation Act* was approved by the U.S. Senate and the U.S. House of Representatives and signed into law by U.S. President Obama. The legislation required a final decision on the Keystone XL Presidential Permit by February 21, 2012.

- On January 18, 2012, DOS announced that the Presidential Permit for Keystone XL was denied because it was unable to determine if the pipeline was in the national interest prior to the end of the two-month Congressional deadline. The denial was not based on the merits of the project.

- The Company, while disappointed, remains fully committed to the construction of Keystone XL. Plans are already underway on a number of fronts to largely maintain the construction schedule of the project. TransCanada will re-apply for a Presidential Permit and expects a new application would be processed in an expedited manner to allow for an in-service date of early 2015.

Natural Gas Pipelines:

- The Alberta System continues to grow through new connections of supply primarily in the Horn River/Montney shale basins in B.C. as well as the deep basin in Alberta.

The Company has filed applications with the National Energy Board (NEB) requesting approval for expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the Western Canada Sedimentary Basin (WCSB). TransCanada has incremental, firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeast B.C. by 2014. Further requests for additional volumes on the Alberta System from the northwest portion of the WCSB have been received.

In 2011, including the projects discussed above, the NEB approved natural gas pipeline projects with capital costs of approximately $910 million. Further pipeline projects with a total capital cost of approximately $810 million are awaiting NEB decision. In addition, infrastructure to connect WCSB supply to markets continues to be pursued particularly to support further development of Alberta oil sands production and to supply proposed liquefied natural gas (LNG) export facilities on the West Coast.

- On September 1, 2011, TransCanada filed a comprehensive application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline, including addressing tolls for 2012 and 2013. On October 31, 2011, TransCanada filed supplementary information on the cost-of-service and proposed tolls for 2012 and 2013. The application results in a 2012 Nova Inventory Transfer System to Dawn toll of $1.29 per gigajoule (GJ) which is $0.82 per GJ or 38 per cent lower than comparable tolls charged in 2011. The oral hearing is scheduled to begin June 4, 2012. A decision on this application is expected in late 2012 or early 2013.

- TransCanada re-filed an application in November 2011 that included supplemental information for approval to construct $130 million of new pipeline infrastructure on the Canadian Mainline that is required to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to eastern markets.

- Gas Transmission Northwest LLC reached a settlement agreement with its shippers for new transportation rates that are effective January 2012 through December 2015 and were approved by the U.S. Federal Energy Regulatory Commission (FERC) in November 2011.

- The Alaska Pipeline Project team continues to work with shippers to resolve conditional bids received as part of the project's open season. The team is also working toward the FERC application deadline of October 2012 for the Alberta option that would transport gas from Alaska to the Alberta System and on to other continental markets. TransCanada has started discussions with Alaska North Slope producers on the LNG option that would require a pipeline from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska.

Energy:

- The refurbishment of Units 1 and 2 at the Bruce Power nuclear facility in Ontario continues to progress. Unit 2 is expected to begin operations in the first quarter of 2012 and Unit 1 is expected to be in service in the third quarter.

  TransCanada's share of the total capital cost is expected to be $2.4 billion. Once the refurbishment is complete, Bruce Power will be the world's largest nuclear facility, capable of providing more than 6,200 MW or about 25 per cent of Ontario's power.

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

- In December 2011, an agreement was announced for the purchase of nine Ontario solar projects with a combined capacity of 86 MW for approximately $470 million. TransCanada will purchase each project once construction and acceptance testing are completed and operations have begun under a 20-year PPA with the OPA under the Feed-In Tariff program.

- The dispute arising out of TransAlta Corporation's claims of force majeure and economic destruction for the Sundance A facility will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

  TransCanada does not believe the owner's claims meet the tests of force majeure or destruction as specified in the PPA and therefore continues to record revenues and costs as though this event is an interruption of supply, in accordance with the terms of the PPA. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

Corporate:

- The Board of Directors of TransCanada declared a quarterly dividend of $0.44 per share for the quarter ending March 31, 2012 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.76 per common share on an annual basis and represents a five per cent increase over the previous amount.

- In November 2011, TransCanada PipeLines Limited (TCPL) issued Medium Term Notes of $500 million and $250 million maturing in 2021 and 2041, respectively, and bearing interest at 3.65 per cent and 4.55 per cent, respectively. The proceeds were used to fund the Alberta System and Canadian Mainline rate bases.

Teleconference – Audio and Slide Presentation:

TransCanada will hold a teleconference and webcast to discuss its 2011 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 before opening the call to questions from analysts and members of the media.

Event:
TransCanada 2011 fourth quarter financial results teleconference and webcast

Date:
Tuesday, February 14, 2012

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

Analysts, members of the media and other interested parties are invited to participate by calling 866.226.1792 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call.

No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EST) February 21, 2012. Please call 905.694.9451 or 800.408.3053 (North America only) and enter pass code 8130635.

With more than 60 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada's network of wholly owned natural gas pipelines extends more than 57,000 kilometres (35,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 380 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 10,800 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com or check us out on Twitter @TransCanada.

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Fourth Quarter 2011 Financial Highlights

Operating Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2011**	2010	Year end ended December 31 **2011**	2010
Revenues	**2,360**	2,057	**9,139**	8,064
Comparable EBITDA[1]	**1,184**	1,005	**4,806**	3,941
Net Income Attributable to Common Shares	**375**	269	**1,527**	1,227
Comparable Earnings[1]	**366**	384	**1,565**	1,361
Cash Flows				
Funds generated from operations[1]	**881**	812	**3,663**	3,331
Decrease/(increase) in operating working capital	**118**	22	**310**	(249)
Net cash provided by operations	**999**	834	**3,973**	3,082
Capital Expenditures	**1,139**	1,471	**3,274**	5,036

Common Share Statistics

(unaudited)	Three months ended December 31 **2011**	2010	Year end ended December 31 **2011**	2010
Net Income per Share - Basic	**$0.53**	$0.39	**$2.18**	$1.78
Comparable Earnings per Share[1]	**$0.52**	$0.55	**$2.23**	$1.97
Dividends Declared per Common Share	**$0.42**	$0.40	**$1.68**	$1.60
Basic Common Shares Outstanding (millions)				
Average for the period	**703**	695	**702**	691
End of period	**704**	696	**704**	696

(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 contains 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", "intend", "target", plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

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

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

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

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

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

- the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits;
- the operating performance of the Company's pipeline and energy assets;

- the availability and price of energy commodities;
- amount of capacity payments and revenues from the Company's energy business;
- regulatory decisions and outcomes;
- outcomes with respect to legal proceedings, including arbitration;
- counterparty performance;
- changes in environmental and other laws and regulations;
- competitive factors in the pipeline and energy sectors;
- construction and completion of capital projects;
- labour, equipment and material costs;
- access to capital markets;
- interest and currency exchange rates;
- weather;
- technological developments; and
- economic conditions in North America.

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

Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this 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 publicly update or revise any forward-looking information in this news release or otherwise, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT, Comparable Interest Expense and Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this news release. These measures do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP). 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, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other and

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

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

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

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

Reconciliation of Non-GAAP Measures

Three months ended December 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines **2011**	2010	Oil Pipelines **2011**	2010	Energy **2011**	2010	Corporate **2011**	2010	Total **2011**	2010
Comparable EBITDA	**739**	737	**179**	-	**295**	301	**(29)**	(33)	**1,184**	1,005
Depreciation and amortization	**(251)**	(241)	**(35)**	-	**(100)**	(103)	**(4)**	-	**(390)**	(344)
Comparable EBIT	**488**	496	**144**	-	**195**	198	**(33)**	(33)	**794**	661
Other Income Statement Items										
Comparable interest expense									**(251)**	(173)
Interest expense of joint ventures									**(15)**	(15)
Comparable interest income and other									**8**	61
Comparable income taxes									**(123)**	(103)
Net income attributable to non-controlling interests									**(33)**	(33)
Preferred share dividends									**(14)**	(14)
Comparable Earnings									**366**	384
Specific items (net of tax):										
Valuation provision for MGP									**-**	(127)
Risk management activities(1)									**9**	12
Net Income Attributable to Common Shares									**375**	269

Three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	**2011**	2010
Comparable Interest Income and Other	**8**	61
Specific item:		
Risk management activities(1)	**35**	-
Interest Income and Other	**43**	61
Comparable Income Taxes	**(123)**	(103)
Specific items:		
Valuation provision for MGP	**-**	19
Risk management activities(1)	**-**	(10)
Income Taxes Expense	**(123)**	(94)
Comparable Earnings per Common Share	**$0.52**	$0.55
Specific items (net of tax):		
Valuation provision for MGP	**-**	(0.18)
Risk management activities	**0.01**	0.02
Net Income per Common Share	**$0.53**	$0.39

(1)

Three months ended December 31 *(unaudited)(millions of dollars)*	**2011**	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**(33)**	24
Natural Gas Storage proprietary inventory and derivatives	**7**	(2)
Foreign exchange derivatives	**35**	-
Income taxes attributable to risk management activities	**-**	(10)
Risk Management Activities	**9**	12

Reconciliation of Non-GAAP Measures

Year ended December 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2011	2010	Oil Pipelines 2011	2010	Energy 2011	2010	Corporate 2011	2010	Total 2011	2010
Comparable EBITDA	**2,967**	2,915	**587**	-	**1,338**	1,125	**(86)**	(99)	**4,806**	3,941
Depreciation and amortization	**(986)**	(977)	**(130)**	-	**(398)**	(377)	**(14)**	-	**(1,528)**	(1,354)
Comparable EBIT	**1,981**	1,938	**457**	-	**940**	748	**(100)**	(99)	**3,278**	2,587
Other Income Statement Items										
Comparable interest expense									**(939)**	(701)
Interest expense of joint ventures									**(55)**	(59)
Comparable interest income and other									**60**	94
Comparable income taxes									**(595)**	(400)
Net income attributable to non-controlling interests									**(129)**	(115)
Preferred share dividends									**(55)**	(45)
Comparable Earnings									**1,565**	1,361
Specific items (net of tax):										
Valuation provision for MGP									**-**	(127)
Risk management activities(1)									**(38)**	(7)
Net Income Attributable to Common Shares									**1,527**	1,227

Year ended December 31 *(unaudited)(millions of dollars except per share amounts)*	2011	2010
Comparable Interest Expense	**(939)**	(701)
Specific item:		
Risk management activities(1)	**2**	-
Interest Expense	**(937)**	(701)
Comparable Interest Income and Other	**60**	94
Specific item:		
Risk management activities(1)	**(5)**	-
Interest Income and Other	**55**	94
Comparable Income Taxes	**(595)**	(400)
Specific items:		
Valuation provision for MGP	**-**	19
Risk management activities(1)	**22**	1
Income Taxes Expense	**(573)**	(380)
Comparable Earnings per Common Share	**$2.23**	$1.97
Specific items (net of tax):		
Valuation provision for MGP	**-**	(0.18)
Risk management activities	**(0.05)**	(0.01)
Net Income per Common Share	**$2.18**	$1.78

(1)

Year ended December 31 *(unaudited)(millions of dollars)*	2011	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**(48)**	2
Canadian Power derivatives	**(3)**	-
Natural Gas Storage proprietary inventory and derivatives	**(6)**	(10)
Interest rate derivatives	**2**	-
Foreign exchange derivatives	**(5)**	-
Income taxes attributable to risk management activities	**22**	1
Risk Management Activities	**(38)**	(7)

Consolidated Results of Operations

Fourth Quarter Results

Comparable Earnings in fourth quarter 2011 were $366 million or $0.52 per share compared to $384 million or $0.55 per share for the same period in 2010. Comparable Earnings in fourth quarter 2011 excluded net unrealized after-tax gains of $9 million ($9 million pre-tax) (2010 - $12 million after-tax gains; $22 million pre-tax) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in fourth quarter 2010 also excluded the $127 million after tax ($146 million pre-tax) valuation provision on advances to the Aboriginal Pipeline Group (APG) for the Mackenzie Gas Project (MGP).

Comparable Earnings decreased $18 million or $0.03 per share in fourth quarter 2011 compared to the same period in 2010 and included the following:

- decreased Comparable EBIT from Natural Gas Pipelines reflecting lower incentive earnings from the Canadian Mainline and the Alberta System and lower revenues from certain U.S. Pipelines partially offset by incremental earnings from Bison and Guadalajara which were placed in service in January and June 2011, respectively;

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

- decreased Comparable EBIT from Energy reflecting lower Bruce A and B volumes and higher operating costs as well as lower realized prices at Bruce B, lower contributions from U.S. Power and lower Natural Gas Storage revenues partially offset by higher realized prices in Western Power and incremental earnings from the start-up of Coolidge in May 2011;

- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service in 2011;

- decreased Comparable Interest Income and Other, reflecting higher realized losses in 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income compared to gains in 2010; and

- increased Comparable Income Taxes due to higher positive income tax adjustments which reduced income taxes in fourth quarter 2010.

TransCanada's Net Income Attributable to Common Shares was $375 million or $0.53 per share in fourth quarter 2011 compared to $269 million or $0.39 per share in fourth quarter 2010.

Annual Results

Comparable Earnings were $1,565 million or $2.23 per share compared to $1,361 million or $1.97 per share for 2010. Comparable Earnings in 2011 excluded net unrealized after-tax losses of $38 million ($60 million pre-tax) (2010 – $7 million after-tax losses ($8 million pre-tax)) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in 2010 also excluded the $127 million after-tax ($146 million pre-tax) valuation provision on advances to the APG for the MGP.

Comparable Earnings increased $204 million or $0.26 per share in 2011 compared to 2010 and included the following:

- increased Comparable EBIT from Natural Gas Pipelines primarily due to incremental earnings from Bison and Guadalajara which were placed in service in January 2011 and June 2011, respectively, lower general, administrative and support costs as well as lower business development spending, partially offset by lower revenues from certain U.S. Pipelines and the negative impact of a weaker U.S. dollar;

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

- increased Comparable EBIT from Energy primarily due to higher realized power prices for Western Power and incremental earnings from Halton Hills and Coolidge, partially offset by lower contributions from Bruce B, Natural Gas Storage and U.S. Power;

- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service and higher interest expense on U.S. dollar-denominated debt issuances in June and September 2010, partially offset by gains on derivatives used to manage the Company's exposure to rising interest rates compared to losses incurred in 2010 and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;

- decreased Comparable Interest Income and Other primarily due to lower realized gains in 2011 compared to 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income;

- increased Comparable Income Taxes primarily due to higher pre-tax earnings in 2011 and higher positive income tax adjustments in 2010 compared to 2011;

- increased Non-Controlling Interests due to the sale of a 25 per cent interest in GTN LLC and Bison LLC to TC PipeLines, LP in May 2011 and the reduction in the Company's ownership interest in TC PipeLines, LP; and

- increased Preferred Share Dividends recorded on preferred shares issued in 2010.

For the year ended December 31, 2011, Net Income Attributable to Common Shares was $1,527 million or $2.18 per share compared to $1,227 million or $1.78 per share in 2010.

Further discussion of the financial results for the fourth quarter and year ended December 31, 2011 is included in the Natural Gas Pipelines, Oil Pipelines, Energy and Other Income Statement Items sections of this news release.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is significantly offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in the Canadian-U.S. foreign exchange rate. The average exchange rate to convert a U.S. dollar to a Canadian dollar for the fourth quarter and year ended December 31, 2011 was 1.02 and 0.99, respectively (2010 – 1.01 and 1.03, respectively).

Summary of Significant U.S. Dollar-Denominated Amounts

(unaudited) *(millions of U.S. dollars, pre-tax)*	Three months ended December 31		Year ended December 31	
	2011	2010	**2011**	2010
U.S. Natural Gas Pipelines Comparable EBIT[1]	**189**	188	**786**	710
U.S. Oil Pipelines Comparable EBIT[1]	**91**	-	**301**	-
U.S. Power Comparable EBIT[1]	**4**	23	**164**	187
Interest on U.S. dollar-denominated long-term debt	**(185)**	(183)	**(734)**	(680)
Capitalized interest on U.S. capital expenditures	**23**	79	**116**	290
U.S. non-controlling interests and other	**(49)**	(44)	**(192)**	(164)
	73	63	**441**	343

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBIT.

Natural Gas Pipelines

Natural Gas Pipelines' Comparable EBIT was $488 million in fourth quarter 2011 compared to $496 million for the same period in 2010. Comparable EBIT in 2010 excluded a $146 million pre-tax valuation provision on advances to the APG for the MGP.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2011**	2010	Year ended December 31 **2011**	2010
Canadian Natural Gas Pipelines				
Canadian Mainline	**262**	269	**1,058**	1,054
Alberta System	**185**	194	**742**	742
Foothills	**31**	33	**127**	135
Other (TQM, Ventures LP)	**12**	11	**50**	50
Canadian Natural Gas Pipelines Comparable EBITDA(1)	**490**	507	**1,977**	1,981
Depreciation and amortization	**(180)**	(180)	**(722)**	(715)
Canadian Natural Gas Pipelines Comparable EBIT(1)	**310**	327	**1,255**	1,266
U.S. Natural Gas Pipelines (in U.S. dollars)				
ANR	**73**	76	**312**	314
GTN(2)	**26**	45	**131**	171
Great Lakes(3)	**20**	26	**101**	109
TC PipeLines, LP(2)(4)(5)	**25**	26	**101**	99
Iroquois	**17**	16	**67**	67
Bison(5)	**14**	-	**49**	-
Portland(6)	**7**	10	**22**	22
International (Tamazunchale, Guadalajara, TransGas, Gas Pacifico/INNERGY)(7)	**25**	8	**77**	42
General, administrative and support costs(8)	**(3)**	(6)	**(9)**	(31)
Non-controlling interests(9)	**54**	48	**202**	173
U.S. Natural Gas Pipelines Comparable EBITDA(1)	**258**	249	**1,053**	966
Depreciation and amortization	**(69)**	(61)	**(267)**	(256)
U.S. Natural Gas Pipelines Comparable EBIT(1)	**189**	188	**786**	710
Foreign exchange	**4**	2	**(8)**	24
U.S. Natural Gas Pipelines Comparable EBIT(1) (in Canadian dollars)	**193**	190	**778**	734
Natural Gas Pipelines Business Development Comparable EBITDA(1)	**(15)**	(21)	**(52)**	(62)
Natural Gas Pipelines Comparable EBIT(1)	**488**	496	**1,981**	1,938
Summary:				
Natural Gas Pipelines Comparable EBITDA(1)	**739**	737	**2,967**	2,915
Depreciation and amortization	**(251)**	(241)	**(986)**	(977)
Natural Gas Pipelines Comparable EBIT(1)	**488**	496	**1,981**	1,938

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Results reflect TransCanada's direct ownership interest of 75 per cent of GTN effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent prior to that date.
(3) Represents TransCanada's 53.6 per cent direct ownership interest.
(4) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. As a result, TC PipeLines, LP's results include TransCanada's decreased ownership in TC PipeLines, LP and TransCanada's effective ownership through TC PipeLines, LP of 8.3 per cent of each of GTN and Bison since May 2011.
(5) Results reflect TransCanada's ownership of 75 per cent of Bison effective May 2011, when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison was placed in service.
(6) Represents TransCanada's 61.7 per cent ownership interest.
(7) Includes Guadalajara effective June 2011.

(8) Represents General, Administrative and Support Costs associated with certain of TransCanada'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.
(9) Non-Controlling Interests reflects Comparable EBITDA for the portions of TC PipeLines, LP and Portland not owned by TransCanada.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited) *(millions of dollars)*	Three months ended December 31		Year ended December 31	
	2011	2010	**2011**	2010
Canadian Mainline	**60**	71	**246**	267
Alberta System	**51**	53	**200**	198
Foothills	**4**	7	**22**	27

Canadian Natural Gas Pipelines

Canadian Mainline's net income in fourth quarter 2011 decreased $11 million to $60 million compared to the same period in 2010. This decrease was primarily due to lower incentive earnings, a lower rate of return on common equity (ROE) as determined by the National Energy Board (NEB) of 8.08 per cent in 2011 compared to 8.52 per cent in 2010, as well as a lower average investment base.

The Alberta System's net income of $51 million in fourth quarter 2011 decreased $2 million compared to the same period in 2010. The lower net income was primarily due to lower incentive earnings, partially offset by the positive impact of a higher average investment base.

Canadian Mainline's Comparable EBITDA of $262 million in fourth quarter 2011 decreased $7 million compared to the same period in 2010. The Alberta System's Comparable EBITDA was $185 million in fourth quarter 2011 compared to $194 million for the same period in 2010. EBITDA from the Canadian Mainline and the Alberta System includes net income variances discussed above as well as flow through items which do not affect net income.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA in fourth quarter 2011 was US$73 million compared to US$76 million for the same period in 2010. The decrease in fourth quarter 2011 was primarily due to higher operations, maintenance and administration (OM&A) costs.

GTN's Comparable EBITDA in fourth quarter 2011 from TransCanada's direct investment was US$26 million compared to US$45 million for the same period in 2010. The decrease was primarily due to TransCanada's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011 and lower revenues.

The Bison pipeline was placed in service on January 14, 2011. TransCanada's portion of Comparable EBITDA from its direct investment was US$14 million in fourth quarter 2011. EBITDA reflects TransCanada's 75 per cent direct interest in Bison subsequent to the sale of a 25 per cent interest in Bison to TC PipeLines, LP in May 2011 and 100 per cent prior to that date.

Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US$145 million in fourth quarter 2011 compared to US$128 million for the same period in 2010. The increases were primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011. In addition, lower general, administrative and support costs increased EBITDA in fourth quarter 2011, offset by lower earnings from Great Lakes and Portland.

Depreciation

Natural Gas Pipelines' Depreciation and Amortization increased $10 million in fourth quarter 2011 compared to the same period in 2010 primarily due to the Guadalajara and Bison pipelines being placed in service in 2011.

Business Development

Natural Gas Pipelines' Business Development Comparable EBITDA losses, resulting from business development expenses, decreased $6 million in fourth quarter 2011 compared to the same period in 2010 primarily due to decreased business development costs related to the Alaska Pipeline Project. Project applicable expenses and reimbursements are shared proportionately with Exxon Mobil Corporation, TransCanada's joint venture partner in developing the Alaska Pipeline Project.

Operating Statistics

Year ended December 31 *(unaudited)*	Canadian Mainline[(1)]		Alberta System[(2)]		Foothills		ANR[(3)]		GTN[(3)]	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Average investment base (millions of dollars)	**6,179**	6,466	**5,074**	4,989	**606**	655	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**1,887**	1,666	**3,517**	3,447	**1,289**	1,446	**1,706**	1,589	**679**	802
Average per day	**5.2**	4.6	**9.6**	9.4	**3.5**	4.0	**4.7**	4.4	**1.9**	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, 2011 were 1,160 billion cubic feet (Bcf) (2010 – 1,228 Bcf); average per day was 3.2 Bcf (2010 – 3.4 Bcf).

(2) Field receipt volumes for the Alberta System for the year ended December 31, 2011 were 3,622 Bcf (2010 – 3,471 Bcf); average per day was 9.9 Bcf (2010 – 9.5 Bcf).

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

Oil Pipelines

Oil Pipelines Comparable EBIT in fourth quarter 2011 was $144 million. At the beginning of February 2011, the Company commenced recording EBITDA for the Wood River/Patoka section of Keystone following the NEB's decision to remove the maximum operating pressure restriction along the conversion section of the system and completion of the required operational modifications. The Cushing Extension was also placed in service at that time.

Oil Pipelines Results

(unaudited)(millions of dollars)	Three months ended December 31 **2011**	Year ended December 31[1] **2011**
Canadian Oil Pipelines Comparable EBITDA[2]	**64**	210
Depreciation and amortization	**(13)**	(49)
Canadian Oil Pipelines Comparable EBIT[2]	**51**	161
U.S. Oil Pipelines Comparable EBITDA[2] (in U.S. dollars)	**113**	383
Depreciation and amortization	**(22)**	(82)
U.S. Oil Pipelines Comparable EBIT[2]	**91**	301
Foreign exchange	**2**	(3)
U.S. Oil Pipelines Comparable EBIT[2] (in Canadian dollars)	**93**	298
Oil Pipelines Business Development Comparable EBITDA and EBIT[2]	**-**	(2)
Oil Pipelines Comparable EBIT[2]	**144**	457
Summary:		
Oil Pipelines Comparable EBITDA[2]	**179**	587
Depreciation and amortization	**(35)**	(130)
Oil Pipelines Comparable EBIT[2]	**144**	457

(1) Results reflect eleven months of operations.
(2) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.

Operating Statistics

(unaudited)	Three months ended December 31 **2011**	Year ended December 31[1] **2011**
Delivery volumes (thousands of barrels)[2]		
Total	**45,050**	**137,384**
Average per day	**490**	**411**

(1) Results reflect eleven months of operations.
(2) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $195 million in fourth quarter 2011 compared to $198 million for the same period in 2010.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2011**	2010	Year ended December 31 **2011**	2010
Canadian Power				
Western Power[1]	**143**	48	**489**	220
Eastern Power[2]	**87**	77	**314**	231
Bruce Power	**33**	99	**252**	298
General, administrative and support costs	**(15)**	(9)	**(43)**	(38)
Canadian Power Comparable EBITDA[3]	**248**	215	**1,012**	711
Depreciation and amortization	**(68)**	(63)	**(276)**	(242)
Canadian Power Comparable EBIT[3]	**180**	152	**736**	469
U.S. Power (in U.S. dollars)				
Northeast Power[4]	**44**	67	**314**	335
General, administrative and support costs	**(12)**	(8)	**(41)**	(32)
U.S. Power Comparable EBITDA[3]	**32**	59	**273**	303
Depreciation and amortization	**(28)**	(36)	**(109)**	(116)
U.S. Power Comparable EBIT[3]	**4**	23	**164**	187
Foreign exchange	**(1)**	1	**(4)**	7
U.S. Power Comparable EBIT[3] (in Canadian dollars)	**3**	24	**160**	194
Natural Gas Storage				
Alberta Storage	**23**	39	**89**	140
General, administrative and support costs	**-**	(2)	**(6)**	(8)
Natural Gas Storage Comparable EBITDA[3]	**23**	37	**83**	132
Depreciation and amortization	**(3)**	(4)	**(14)**	(15)
Natural Gas Storage Comparable EBIT[3]	**20**	33	**69**	117
Energy Business Development Comparable EBITDA and EBIT[3]	**(8)**	(11)	**(25)**	(32)
Energy Comparable EBIT[3]	**195**	198	**940**	748
Summary:				
Energy Comparable EBITDA[3]	**295**	301	**1,338**	1,125
Depreciation and amortization	**(100)**	(103)	**(398)**	(377)
Energy Comparable EBIT[3]	**195**	198	**940**	748

(1) Includes Coolidge effective May 2011.
(2) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011 and Halton Hills effective September 2010.
(3) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(4) Includes phase two of Kibby Wind effective October 2010.

Canadian Power

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

(unaudited) (millions of dollars)	Three months ended December 31 2011	2010	Year ended December 31 2011	2010
Revenues				
Western power(2)	**294**	180	**1,081**	714
Eastern power(3)	**125**	113	**475**	330
Other(4)	**14**	20	**70**	84
	433	313	**1,626**	1,128
Commodity Purchases Resold				
Western power	**(137)**	(117)	**(538)**	(431)
Other(4)(5)	**4**	(2)	**(9)**	(26)
	(133)	(119)	**(547)**	(457)
Plant operating costs and other	**(70)**	(69)	**(276)**	(220)
General, administrative and support costs	**(15)**	(9)	**(43)**	(38)
Comparable EBITDA(1)	**215**	116	**760**	413
Depreciation and amortization	**(40)**	(39)	**(163)**	(140)
Comparable EBIT(1)	**175**	77	**597**	273

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge effective May 2011.
(3) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011 and Halton Hills effective September 2010.
(4) Includes sales of excess natural gas purchased for generation and thermal carbon black. The net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets are presented on a net basis in Other Revenues.
(5) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics

(unaudited)	Three months ended December 31 2011	2010	Year ended December 31 2011	2010
Sales Volumes (GWh)				
Supply				
Generation				
Western Power(1)	**669**	622	**2,606**	2,373
Eastern Power(2)	**852**	874	**3,714**	2,359
Purchased				
Sundance A & B and Sheerness PPAs(3)	**1,875**	3,030	**7,909**	10,785
Other purchases	**384**	118	**1,112**	429
	3,780	4,644	**15,341**	15,946
Sales				
Contracted				
Western Power	**2,464**	2,843	**9,245**	10,211
Eastern Power	**852**	875	**3,714**	2,375
Spot				
Western Power	**464**	926	**2,382**	3,360
	3,780	4,644	**15,341**	15,946
Plant Availability(4)				
Western Power(1)(5)	**97%**	96%	**97%**	95%
Eastern Power(2)(6)	**88%**	92%	**93%**	94%

(1) Includes Coolidge effective May 2011.
(2) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011 and Halton Hills effective September 2010.
(3) No volumes were delivered under the Sundance A PPA in 2011.
(4) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(5) Excludes facilities that provide power to TransCanada under PPAs.
(6) Bécancour has been excluded from the availability calculation as power generation at the facility has been suspended since 2008.

Western Power's Comparable EBITDA of $143 million and Power revenues of $294 million in fourth quarter 2011 increased $95 million and $114 million, respectively, compared to the same period in 2010, primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year power purchase arrangement (PPA) in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 65 per cent to $76 per megawatt hour (MWh) in fourth quarter 2011 compared to $46 per MWh in fourth quarter 2010.

Western Power's Comparable EBITDA in fourth quarter 2011 included $57 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA.

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

TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

Eastern Power's Comparable EBITDA of $87 million and Power Revenues of $125 million in fourth quarter 2011 increased $10 million and $12 million, respectively, compared to the same period in 2010 primarily due to higher Bécancour contractual earnings.

Western Power's Commodity Purchases Resold of $137 million increased $20 million, compared to the same period in 2010 due to increased direct sales to customers.

Approximately 84 per cent of Western Power sales volumes were sold under contract in fourth quarter 2011, compared to 75 per cent in fourth quarter 2010. To reduce its exposure to spot market prices in Alberta, as at December 31, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 8,400 gigawatt hours (GWh) for 2012 and 6,200 GWh for 2013.

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

Bruce Power Results

(TransCanada's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended December 31 **2011**	2010	Year ended December 31 **2011**	2010
Revenues[1]	**181**	228	**817**	862
Operating Expenses	**(148)**	(129)	**(565)**	(564)
Comparable EBITDA[2]	**33**	99	**252**	298
Bruce A Comparable EBITDA[2]	**(1)**	33	**98**	91
Bruce B Comparable EBITDA[2]	**34**	66	**154**	207
Comparable EBITDA[2]	**33**	99	**252**	298
Depreciation and amortization	**(28)**	(24)	**(113)**	(102)
Comparable EBIT[2]	**5**	75	**139**	196
Bruce Power – Other Information				
Plant availability[3]				
Bruce A	**68%**	94%	**90%**	81%
Bruce B	**89%**	91%	**88%**	91%
Combined Bruce Power	**82%**	92%	**89%**	88%
Planned outage days				
Bruce A	**55**	-	**60**	60
Bruce B	**43**	16	**135**	70
Unplanned outage days				
Bruce A	**3**	9	**16**	64
Bruce B	**-**	-	**24**	34
Sales volumes (GWh)				
Bruce A	**1,050**	1,470	**5,475**	5,026
Bruce B	**1,956**	2,082	**7,859**	8,184
	3,006	3,552	**13,334**	13,210
Results per MWh				
Bruce A power revenues	**$66**	$65	**$66**	$65
Bruce B power revenues[4]	**$53**	$60	**$54**	$58
Combined Bruce Power revenues	**$56**	$61	**$57**	$60

(1) Revenues include Bruce A's fuel cost recoveries of $3 million and $24 million for fourth quarter and year ended December 31, 2011, respectively (2010 – $8 million and $29 million, respectively).
(2) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(3) Plant availability represents the percentage of time in a year 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 as well as volumes and revenues associated with deemed generation.

TransCanada's proportionate share of Bruce A's Comparable EBITDA decreased $34 million to a loss of $1 million in fourth quarter 2011 compared to EBITDA of $33 million in fourth quarter 2010. The decrease was primarily due to lower volumes reflecting the November 6, 2011 commencement of the approximate six-month West Shift Plus planned outage as part of the life extension strategy for Unit 3.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $32 million to $34 million in fourth quarter 2011 compared to $66 million in fourth quarter 2010 due to higher operating costs, lower volumes due to increased planned outage days and lower realized prices resulting from the expiry of fixed-price contracts at higher prices.

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

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues were subject to repayment in 2011 or 2010.

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 decreased by $7 per MWh to $53 per MWh in fourth quarter 2011 compared to fourth quarter 2010, and reflected revenues recognized from the floor price mechanism, contract sales and deemed generation. The decrease was the result of the majority of higher-priced contracts entered into in previous years expiring by the end of December 2010.

As at December 31, 2011, TransCanada's share of the total capital cost of the Bruce A refurbishment and restart of Units 1 and 2 was approximately $2.3 billion.

U.S. Power

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

(unaudited) *(millions of U.S. dollars)*	Three months ended December 31 **2011**	2010	Year ended December 31 **2011**	2010
Revenues				
Power[3]	**160**	238	**919**	1,090
Capacity	**44**	51	**227**	231
Other[3][4]	**26**	24	**80**	78
	230	313	**1,226**	1,399
Commodity purchases resold[3]	**(71)**	(123)	**(398)**	(543)
Plant operating costs and other[4]	**(115)**	(123)	**(514)**	(521)
General, administrative and support costs	**(12)**	(8)	**(41)**	(32)
Comparable EBITDA[1]	**32**	59	**273**	303
Depreciation and amortization	**(28)**	(36)	**(109)**	(116)
Comparable EBIT[1]	**4**	23	**164**	187

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

U.S. Power Operating Statistics[1]

(unaudited)	Three months ended December 31 **2011**	2010	Year ended December 31 **2011**	2010
Physical Sales Volumes (GWh)				
Supply				
Generation	**1,511**	1,672	**6,880**	6,755
Purchased	**1,241**	1,838	**6,018**	8,899
	2,752	3,510	**12,898**	15,654
Plant Availability[2][3]	**83%**	70%	**87%**	86%

(1) Includes phase two of Kibby Wind effective October 2010.

(2) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(3) Plant availability in fourth quarter 2011 and 2010 was primarily affected by planned outages at Ravenswood.

U.S. Power's Comparable EBITDA in fourth quarter 2011 of US$32 million decreased US$27 million compared to the same period in 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes partially offset by new sales activity in the PJM Interconnection area (PJM).

Physical sales volumes decreased in fourth quarter 2011 compared to the same period in 2010 due to decreased demand as a result of unseasonable weather and reduced opportunities for wholesale contracts. As well, fewer physical transactions were used to cover power sales commitments during fourth quarter 2011, in favour of financial transactions, compared to the same period in 2010.

U.S. Power's Power Revenues in fourth quarter 2011 of US$160 million decreased US$78 million from US$238 million in the same period in 2010 primarily due to lower physical sales volumes and lower prices partially offset by new sales activity in the New York and PJM markets.

Capacity Revenues of US$44 million decreased US$7 million in fourth quarter 2011 compared to fourth quarter 2010. Capacity prices have been negatively impacted since July 2011 by the manner in which the New York Independent System Operator (NYISO) has applied pricing rules in this market. TransCanada and others have filed formal complaints with the Federal Energy Regulatory Commission (FERC) alleging that the NYISO has inappropriately applied these pricing rules. The complaints are currently pending before the FERC. Reduced capacity prices were partially offset by lower forced outage rates at Ravenswood.

Commodity Purchases Resold of US$71 million in fourth quarter 2011 decreased US$52 million from US$123 million in the same period in 2010 primarily due to a decrease in the quantity of physical power purchased for resale under U.S. Power's power sales commitments to wholesale, commercial and industrial customers in New England partially offset by new activity in the New York and PJM markets.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, in fourth quarter 2011 of US$115 million decreased US$8 million from the same period in 2010 primarily due to decreased fuel costs as a result of decreased generation and commodity prices.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM power markets. Exposures to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts. As at December 31, 2011, approximately 3,600 GWh or 30 per cent for 2012 and 1,000 GWh or 10 per cent for 2013 of U.S. Power's planned generation is contracted forward. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets, and power sales fluctuate based on customer usage.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA in fourth quarter 2011 was $23 million compared to $37 million for the same period in 2010. The decrease of $14 million in Comparable EBITDA in fourth quarter 2011 was primarily due to decreased proprietary natural gas and third party storage revenues as a result of lower realized natural gas price spreads.

Other Income Statement Items

Comparable Interest Expense

(unaudited) *(millions of dollars)*	Three months ended December 31 **2011**	 2010	Year ended December 31 **2011**	 2010
Interest on long-term debt[2]				
Canadian dollar-denominated	**125**	126	**490**	514
U.S. dollar-denominated	**185**	183	**734**	680
Foreign exchange	**4**	2	**(7)**	20
	314	311	**1,217**	1,214
Other interest and amortization	**8**	12	**24**	74
Capitalized interest	**(71)**	(150)	**(302)**	(587)
Comparable Interest Expense[1]	**251**	173	**939**	701

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

Comparable Interest Expense in fourth quarter 2011 increased $78 million to $251 million from $173 million in fourth quarter 2010. The increase primarily reflected lower capitalized interest upon placing Keystone and other new assets in service in 2011.

Comparable Interest Income and Other in fourth quarter 2011 decreased $53 million to $8 million from income of $61 million in fourth quarter 2010. The decrease in fourth quarter reflected realized losses in 2011 compared to gains in 2010 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable Income Taxes were $123 million in fourth quarter 2011 compared to $103 million for the same period in 2010. The increase was primarily due to higher positive income tax adjustments that reduced income taxes in fourth quarter 2010 compared to 2011.

Consolidated Income

(unaudited) *(millions of dollars except per share amounts)*	Three months ended December 31 2011	Three months ended December 31 2010	Year ended December 31 2011	Year ended December 31 2010
Revenues	**2,360**	2,057	**9,139**	8,064
Operating and Other Expenses				
Plant operating costs and other	**993**	786	**3,449**	3,114
Commodity purchases resold	**209**	244	**941**	1,017
Depreciation and amortization	**390**	344	**1,528**	1,354
Valuation provision for MGP	**-**	146	**-**	146
	1,592	1,520	**5,918**	5,631
Financial Charges/(Income)				
Interest expense	**251**	173	**937**	701
Interest expense of joint ventures	**15**	15	**55**	59
Interest income and other	**(43)**	(61)	**(55)**	(94)
	223	127	**937**	666
Income before Income Taxes	**545**	410	**2,284**	1,767
Income Taxes Expense/(Recovery)				
Current	**12**	26	**209**	(141)
Future	**111**	68	**364**	521
	123	94	**573**	380
Net Income	**422**	316	**1,711**	1,387
Net Income Attributable to Non-Controlling Interests	**33**	33	**129**	115
Net Income Attributable to Controlling Interests	**389**	283	**1,582**	1,272
Preferred Share Dividends	**14**	14	**55**	45
Net Income Attributable to Common Shares	**375**	269	**1,527**	1,227
Net Income per Common Share				
Basic	**$0.53**	$0.39	**$2.18**	$1.78
Diluted	**$0.53**	$0.39	**$2.17**	$1.77
Average Common Shares Outstanding – Basic (millions)	**703**	695	**702**	691
Average Common Shares Outstanding – Diluted (millions)	**704**	696	**703**	692

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended December 31 **2011**	2010	Year ended December 31 **2011**	2010
Cash Generated From Operations				
Net income	**422**	316	**1,711**	1,387
Depreciation and amortization	**390**	344	**1,528**	1,354
Future income taxes	**111**	68	**364**	521
Employee future benefits funding in excess of expense	**(5)**	(33)	**(3)**	(69)
Valuation provision for MGP	**-**	146	**-**	146
Other	**(37)**	(29)	**63**	(8)
	881	812	**3,663**	3,331
Decrease/(increase) in operating working capital	**118**	22	**310**	(249)
Net cash provided by operations	**999**	834	**3,973**	3,082
Investing Activities				
Capital expenditures	**(1,139)**	(1,471)	**(3,274)**	(5,036)
Deferred amounts and other	**(90)**	46	**(14)**	(384)
Net cash used in investing activities	**(1,229)**	(1,425)	**(3,288)**	(5,420)
Financing Activities				
Dividends on common and preferred shares	**(310)**	(187)	**(1,016)**	(754)
Distributions paid to non-controlling interests	**(44)**	(29)	**(131)**	(112)
Notes payable issued/(repaid), net	**37**	527	**(218)**	474
Long-term debt issued, net of issue costs	**1,049**	34	**1,622**	2,371
Repayment of long-term debt	**(326)**	(65)	**(1,272)**	(494)
Long-term debt of joint ventures issued	**2**	13	**48**	177
Repayment of long-term debt of joint ventures	**(20)**	(22)	**(102)**	(254)
Common shares issued, net of issue costs	**19**	6	**58**	26
Preferred shares issued, net of issue costs	**-**	-	**-**	679
Partnership units of subsidiary issued, net of issue costs	**-**	-	**321**	-
Net cash provided by/(used in) financing activities	**407**	277	**(690)**	2,113
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(8)**	(16)	**6**	(8)
Increase/(Decrease) in Cash and Cash Equivalents	**169**	(330)	**1**	(233)
Cash and Cash Equivalents				
Beginning of period	**596**	1,094	**764**	997
Cash and Cash Equivalents				
End of period	**765**	764	**765**	764

Consolidated Balance Sheet

December 31 *(unaudited)(millions of dollars)*	**2011**	2010
ASSETS		
Current Assets		
Cash and cash equivalents	**765**	764
Accounts receivable	**1,265**	1,271
Inventories	**416**	425
Other	**1,194**	870
	3,640	3,330
Plant, Property and Equipment	**38,262**	36,244
Goodwill	**3,650**	3,570
Regulatory Assets	**1,405**	1,512
Intangibles and Other Assets	**2,038**	2,138
	48,995	46,794
LIABILITIES		
Current Liabilities		
Notes payable	**1,880**	2,092
Accounts payable	**2,659**	2,272
Accrued interest	**373**	367
Current portion of long-term debt	**935**	894
Current portion of long-term debt of joint ventures	**33**	65
	5,880	5,690
Regulatory Liabilities	**303**	314
Deferred Amounts	**805**	694
Future Income Taxes	**3,788**	3,398
Long-Term Debt	**17,632**	17,028
Long-Term Debt of Joint Ventures	**789**	801
Junior Subordinated Notes	**1,009**	985
	30,206	28,910
EQUITY		
Controlling Interests	**17,324**	16,727
Non-controlling interests	**1,465**	1,157
	18,789	17,884
	48,995	46,794

Segmented Information

Three months ended December 31 (unaudited) (millions of dollars)	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines[1] 2011	Oil Pipelines[1] 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Revenues	1,206	1,103	252	-	902	954	-	-	2,360	2,057
Plant operating costs and other[2]	(467)	(366)	(73)	-	(424)	(387)	(29)	(33)	(993)	(786)
Commodity purchases resold	-	-	-	-	(209)	(244)	-	-	(209)	(244)
Depreciation and amortization	(251)	(241)	(35)	-	(100)	(103)	(4)	-	(390)	(344)
Valuation provision for MGP	-	(146)	-	-	-	-	-	-	-	(146)
	488	350	144	-	169	220	(33)	(33)	768	537
Interest expense									(251)	(173)
Interest expense of joint ventures									(15)	(15)
Interest income and other									43	61
Income taxes expense									(123)	(94)
Net Income									422	316
Net Income Attributable to Non-Controlling Interests									(33)	(33)
Net Income Attributable to Controlling Interests									389	283
Preferred Share Dividends									(14)	(14)
Net Income Attributable to Common Shares									375	269

Year ended December 31 (unaudited) (millions of dollars)	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines[1] 2011	Oil Pipelines[1] 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Revenues	4,500	4,373	827	-	3,812	3,691	-	-	9,139	8,064
Plant operating costs and other[2]	(1,533)	(1,458)	(240)	-	(1,590)	(1,557)	(86)	(99)	(3,449)	(3,114)
Commodity purchases resold	-	-	-	-	(941)	(1,017)	-	-	(941)	(1,017)
Depreciation and amortization	(986)	(977)	(130)	-	(398)	(377)	(14)	-	(1,528)	(1,354)
Valuation provision for MGP	-	(146)	-	-	-	-	-	-	-	(146)
	1,981	1,792	457	-	883	740	(100)	(99)	3,221	2,433
Interest expense									(937)	(701)
Interest expense of joint ventures									(55)	(59)
Interest income and other									55	94
Income taxes expense									(573)	(380)
Net Income									1,711	1,387
Net Income Attributable to Non-Controlling Interests									(129)	(115)
Net Income Attributable to Controlling Interests									1,582	1,272
Preferred Share Dividends									(55)	(45)
Net Income Attributable to Common Shares									1,527	1,227

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

(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.