NewsRelease

TransCanada Reports 19 Per Cent Increase in 2013 Comparable Earnings Increases Common Share Dividend by Four Per Cent

CALGARY, Alberta – **February 20, 2014** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for fourth quarter 2013 of $410 million or $0.58 per share compared to $318 million or $0.45 per share for the same period in 2012. For the year ended December 31, 2013, comparable earnings were $1.6 billion or $2.24 per share compared to $1.3 billion or $1.89 per share in 2012. Net income attributable to common shares for fourth quarter 2013 was $420 million or $0.59 per share compared to $306 million or $0.43 per share in fourth quarter 2012. For the year ended December 31, 2013, net income attributable to common shares was $1.7 billion or $2.42 per share compared to $1.3 billion or $1.84 per share in 2012. TransCanada's Board of Directors also declared a quarterly dividend of $0.48 per common share for the quarter ending March 31, 2014, equivalent to $1.92 per common share on an annualized basis, an increase of four per cent. This is the fourteenth consecutive year the Board of Directors has raised the dividend.

"Our diverse portfolio of critical energy infrastructure assets generated strong earnings and cash flow in 2013," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings increased 19 per cent to $1.6 billion and funds generated from operations were up 22 per cent to $4 billion. The strong year over year results reflect a return to an eight unit site at Bruce Power, higher Western Power volumes, an increase in New York capacity prices, growth in our NGTL System, and a higher Canadian Mainline return on equity."

During 2013 we also captured an additional $19 billion of commercially secured growth opportunities. They include the Prince Rupert Gas Transmission project that would move natural gas to Canada's West Coast for liquefaction and shipment to Asian markets, further expansion of the NGTL System, the Heartland and TC Terminals crude oil infrastructure projects in Alberta, and the Energy East Pipeline project which, in addition to new build, would include the conversion of a portion of our existing Canadian Mainline from natural gas to crude oil service and link growing crude oil production in Western Canada to refineries and export terminals in Eastern Canada.

"We now have a $38 billion portfolio of commercially secured projects backed by long-term contracts," added Girling. "Looking forward, we will remain focused on obtaining the necessary approvals and constructing this high-quality portfolio of energy infrastructure assets that are expected to generate significant growth in earnings and cash flow as they are placed into service over the remainder of the decade."

On January 22, 2014, we reached a significant milestone in advancing our unprecedented capital program when the approximate US$2.6 billion Gulf Coast Project began delivering crude oil from Cushing, Oklahoma to refineries on the U.S. Gulf Coast. This vital piece of infrastructure extends our existing Keystone Pipeline System which has safely delivered more than 550 million barrels of oil from Western Canada to key refining markets in the U.S. Midwest since it commenced operations in 2010.

Fourth Quarter and Year-End Highlights

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

- Fourth quarter financial results
    - Net income attributable to common shares of $420 million or $0.59 per share
    - Comparable earnings of $410 million or $0.58 per share
    - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.3 billion
    - Funds generated from operations of $1.1 billion

- For the year ended December 31, 2013
  - Net income attributable to common shares of $1.7 billion or $2.42 per share
  - Comparable earnings of $1.6 billion or $2.24 per share
  - Comparable EBITDA of $4.9 billion
  - Funds generated from operations of $4.0 billion
- Announced an increase in the quarterly common share dividend of four per cent to $0.48 per share for the quarter ending March 31, 2014
- Placed the US$2.6 billion Gulf Coast Project into service on January 22, 2014
- Received the U.S. Department of State (DOS) Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL Pipeline on January 31, 2014
- Acquired our fourth Ontario Solar facility for $62 million on December 31, 2013
- Signed a Heads of Agreement (HOA) with the State of Alaska and North Slope producers to advance the proposed Alaska LNG Project in January 2014
- Reached an agreement in January 2014 to sell Cancarb Limited (Cancarb) and its related power generation facility for aggregate gross proceeds of $190 million

Comparable earnings for fourth quarter 2013 were $410 million or $0.58 per share compared to $318 million or $0.45 per share for the same period in 2012. Higher earnings from the Canadian Mainline, the NGTL System, Keystone, and Bruce Power were partially offset by lower contributions from U.S. Natural Gas Pipelines and Western Power.

Comparable earnings for the year ended December 31, 2013 were $1.584 billion or $2.24 per share compared to $1.330 billion or $1.89 per share in 2012. Higher earnings from the Canadian Mainline, the NGTL System, Keystone, Bruce Power, U.S. Power, and Western Power were partially offset by lower contributions from U.S. Natural Gas Pipelines.

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

Oil Pipelines:

- *Gulf Coast Project*: On January 22, 2014 crude oil transportation service commenced on the 780 kilometre (km) (485 mile) 36-inch pipeline which extends from Cushing, Oklahoma to Nederland, Texas. The pipeline, which is expected to have an average capacity of 520,000 barrels per day (bbl/d) in its first year of operation, will play a critical role in connecting growing North American crude oil production with the continent's largest refining centre in the U.S. Gulf Coast.

  Construction continues on the US$400 million 77 km (48 mile) Houston Lateral pipeline and terminal to transport crude oil to Houston, Texas refineries. We anticipate the capacity of the lateral will be similar to that of the Gulf Coast Project and the terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in mid-2015.

- *Keystone XL:* On January 31, 2014, the DOS released its FSEIS for the Keystone XL Pipeline. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is "unlikely to significantly impact the rate of extraction in the oil sands" and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period of up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment.

  On February 19, 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL Pipeline. We are disappointed and disagree with the decision of the Nebraska district court and will now analyze the judgment and decide what next steps may be taken. Nebraska's Attorney General has filed an appeal.

  We anticipate the pipeline, which will extend from Hardisty, Alberta to Steele City, Nebraska, to be in service approximately two years following the receipt of the Presidential Permit. The US$5.4 billion cost estimate will increase depending on the timing and conditions of the permit. As of December 31, 2013, we have invested US$2.2 billion in the project.

- *Energy East Pipeline:* We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. We intend to file the necessary regulatory applications in mid-2014 for approvals to construct and operate the pipeline project and terminal facilities.

  The 1.1 million bbl/d Energy East Pipeline project received approximately 900,000 bbl/d of firm, long-term contracts during a binding open season to transport crude oil from Western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, it is anticipated to commence deliveries to Québec in 2018 with service to New Brunswick expected to follow in late 2018.

- *Northern Courier Pipeline:* In October 2013, Suncor Energy announced that the Fort Hills Energy Limited Partnership is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project, which is expected to be completed in advance of mine start-up and cost approximately $800 million, will transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.

  We filed a permit application for the project with the Alberta Energy Regulator (AER) after completing the required Aboriginal and stakeholder engagement and associated field work.

- *Heartland Pipeline and TC Terminals*: In October 2013, we filed a permit application with the AER for the Heartland Pipeline, after completing the required Aboriginal and stakeholder engagement and associated field work. In February 2014, the application for the TC Terminals facility was approved by the AER.

  The projects will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton. We anticipate the pipeline could transport up to 900,000 bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to be in service in 2016.

Natural Gas Pipelines:

- *Canadian Mainline:* In July 2013, we implemented the National Energy Board's (NEB) decision on our Canadian Mainline Restructuring Proposal application. The NEB decision introduced several new elements that were not part of our application, including fixing tolls for contracted capacity outside the time frame that was applied for and the ability to price discretionary services at market rates. Having secured additional firm transportation service contracts since July 2013, along with the ability to price discretionary services, allowed us to realize our net revenue requirement in 2013, which included a return on equity of 11.50 per cent on 40 per cent equity.

  In December 2013, we filed for NEB approval of a settlement reached with three eastern Canadian local natural gas distribution customers. The settlement is intended to provide a stable, long-term solution to meet demand growth in the Eastern Triangle and address anticipated lower demand for transportation service on the remainder of the system while providing a reasonable opportunity to recover our costs. Under the settlement, the base return on equity would be set at 10.10 per cent on 40 per cent equity. After a $20 million (after tax) annual contribution from 2015 to 2020 and various incentive mechanisms, the return on equity could range from 8.70 to 11.50 per cent.

  The Mainline is expected to operate under the current NEB tolling framework in 2014. The settlement, if approved, will address tolls from 2015 through 2020 with certain aspects of tolling to be applied through 2030, and resolve tolls for 2014.

On January 31, 2014, shippers on the Canadian Mainline elected to renew approximately 2.5 billion cubic feet a day of their contracts through November 2016.

- *NGTL System Expansion:* In addition to completing and placing into service approximately $730 million of pipeline projects in 2013 to expand and extend the NGTL System, the NEB approved approximately $290 million of additional expansions that are currently in various stages of development or construction, but not yet in-service.

  On November 8, 2013, we filed an application with the NEB to construct and operate the North Montney Project, which is an extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of British Columbia and underpinned by long-term contracts. The estimated capital cost of the project is $1.7 billion and it consists of approximately 300 km (186 miles) of pipeline.

- *NGTL System Rate Settlement:* On November 1, 2013, the NEB approved our NGTL System 2013-2014 settlement and final 2013 rates as filed. The settlement fixes the allowed return on equity at 10.10 per cent on 40 per cent deemed common equity, establishes an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixes the operations, maintenance and administration costs for 2013 at $190 million and 2014 at $198 million with any variance to our account.

- *Tamazunchale Pipeline Extension Project:* Construction is proceeding on the US$500 million Tamazunchale Pipeline Extension Project although delays have occurred due to a significant number of archeological finds along the pipeline route. It is expected these finds and the related impact on construction will move the project's scheduled in-service date to second quarter 2014. As these types of finds are not uncommon in significant infrastructure projects in Mexico, contractual relief for such delays is provided. We continue to work with local, state and federal authorities to minimize and mitigate ground disturbance at the specific sites as well as to minimize impact to the scheduled in-service date.

- *ANR Lebanon Lateral Reversal Project:* Following a successful binding open season which concluded in October 2013, we have executed firm transportation contracts for 350 million cubic feet per day at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal Project, which will entail modifications to existing facilities. The facility modifications are expected to be completed in first quarter 2014. Contracted volumes will increase over the course of 2014 generating incremental earnings. The project will substantially increase our ability to receive gas on ANR's southeast mainline from the Utica/Marcellus shale plays.

- *Great Lakes Rate Settlement*: In November 2013, we received Federal Energy Regulatory Commission (FERC) approval for a rate settlement with shippers on Great Lakes Gas Transmission. Commencing November 1, 2013, maximum recourse rates increased by approximately 21 per cent resulting in a modest increase in the portion of Great Lakes' revenue derived from recourse rate contracts. The settlement includes a 17 month moratorium through March 31, 2015 and requires Great Lakes to have new rates in effect by January 1, 2018.

- *Alaska LNG Project:* On January 14, 2014, the State of Alaska, TransCanada, the three major Alaska North Slope (ANS) gas producers, and the Alaska Gasline Development Corporation signed a HOA relating to a gas pipeline and liquefied natural gas project to bring ANS natural gas resources to market. Under the HOA and a related Memorandum of Understanding, the State of Alaska and TransCanada have agreed that an LNG export project, rather than a pipeline to Alberta, is currently the best opportunity to commercialize ANS gas resources, and that our license under the Alaska Gasline Inducement Act will be amicably terminated. The HOA seeks to establish a transparent set of principles and a roadmap outlining how all six parties will work together to advance the Alaska LNG Project. It is anticipated that two years of front end engineering will be completed before further commitments to commercialize the project will be made.

Energy:

- *Sundance A:* Units 1 and 2 returned to service in September and October 2013, respectively. The operator shut down both units in December 2010 under a claim of force majeure and was ordered by an arbitration panel in July 2012 to rebuild them. Combined, the units are capable of generating 560 megawatts (MW).

- *Ravenswood:* Capacity prices in the New York City Zone J market, where Ravenswood operates, are established through a series of forward auctions and utilize a demand curve administered price for purposes of setting the monthly spot price. The demand curve, among other inputs, uses assumptions with respect to the expected cost of the most likely peaking generation technology applicable to new entrants into the market. On January 28, 2014, the FERC accepted a new rate for the demand curve that was filed by the New York Independent System Operator as part of its triennial Demand Curve Reset (DCR) process. The filing changed the generation technology used in the DCR versus that used during the last reset process. We do not expect this change to impact capacity prices in 2014, however, this new assumption does have the potential to negatively affect New York City capacity prices in 2015 and 2016.

- *Ontario Solar:* In late 2011, we agreed to buy nine Ontario solar facilities (combined capacity of 86 MW) from Canadian Solar Solutions Inc. for approximately $500 million. On December 31, 2013, we completed the acquisition of our fourth facility for $62 million which has a capacity of 10 MW. We expect the acquisition of the remaining five facilities to close in 2014, subject to regulatory approvals and satisfactory completion of the related construction activities. All power produced by the facilities is sold under 20-year power purchase arrangements with the Ontario Power Authority.

- *Cancarb:* In January 2014, we reached an agreement to sell Cancarb and its related power generation facility for $190 million, subject to closing adjustments. The sale is expected to close late in first quarter 2014.

- *Bruce Power:* On January 31, 2014, Cameco announced it had agreed to sell its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We are considering our option to increase our Bruce B ownership percentage.

Corporate:

- *Common Dividend:* Our Board of Directors declared a quarterly dividend of $0.48 per share for the quarter ending March 31, 2014 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.92 per common share on an annualized basis and represents a four per cent increase over the previous amount.

- *Financing Activity:*
    - In October 2013, we redeemed all four million outstanding TransCanada PipeLines Limited (TCPL) 5.60 per cent Cumulative Redeemable First Preferred Shares Series U at a price of $50 per share plus $0.5907 of accrued and unpaid dividends. The total face value of the outstanding Series U Shares was $200 million and they carried an aggregate of $11 million in annualized dividends.

    - In October 2013, we issued US$625 million of senior notes maturing on October 16, 2023, bearing interest at 3.75 per cent, and US$625 million of senior notes maturing on October 16, 2043, bearing interest at 5.00 per cent.

      In January 2014, we completed a public offering of 18 million Series 9 Cumulative Redeemable First Preferred Shares. The Series 9 shares were issued at a price of $25 per share, resulting in gross proceeds of $450 million. The initial dividend rate is fixed to October 30, 2019 at $1.0625 per share per annum paid quarterly.

The net proceeds of these offerings will be used for general corporate purposes and to reduce short-term indebtedness, which was used to fund a portion of our capital program and for general corporate purposes.

  - Also in January 2014, we announced that we will redeem all four million outstanding TCPL 5.60 per cent Cumulative Redeemable First Preferred Shares Series Y at a price of $50 per share plus $0.2455 of accrued and unpaid dividends on March 5, 2014. The total face value of the outstanding Series Y Shares is $200 million and they carry an aggregate of $11 million in annualized dividends.

- *Management Changes:* Effective February 28, 2014, Greg Lohnes, Executive Vice-President, Operations and Major Projects and Sean McMaster, Executive Vice-President, Stakeholder Relations, General Counsel and Chief Compliance Officer will retire from the Company.

  Effective March 1, 2014, Alex Pourbaix is appointed Executive Vice-President and President, Development; Paul Miller is appointed Executive Vice-President and President, Liquids Pipelines; Bill Taylor is appointed Executive Vice-President and President, Energy; James Baggs is appointed Executive Vice-President, Operations and Engineering; and Kristine Delkus is appointed Executive Vice-President, General Counsel and Chief Compliance Officer.

Teleconference – Audio and Slide Presentation:

We will hold a teleconference and webcast on Thursday, February 20, 2014 to discuss our fourth quarter 2013 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 at 12 p.m. (MT) / 2 p.m. (ET).

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 (ET) on February 27, 2014. Please call 800.408.3053 or 905.694.9451 and enter pass code 6573719.

With more than 60 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,500 kilometres (42,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with more than 400 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 11,800 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 or **http://blog.transcanada.com**.

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Fourth quarter 2013 and financial highlights

Comparable EBITDA, comparable earnings, comparable earnings per common share and funds generated from operations are all non-GAAP measures. See the non-GAAP measures section for more information.

(unaudited - millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2013	2012	2013	2012
Revenue	**2,332**	2,089	**8,797**	8,007
Comparable EBITDA	**1,291**	1,052	**4,859**	4,245
Net income attributable to common shares	**420**	306	**1,712**	1,299
per common share - basic	**$0.59**	$0.43	**$2.42**	$1.84
Comparable earnings	**410**	318	**1,584**	1,330
per common share	**$0.58**	$0.45	**$2.24**	$1.89
Operating cash flow				
Funds generated from operations	**1,083**	818	**4,000**	3,284
(Increase)/decrease in operating working capital	**(74)**	207	**(326)**	287
Net cash provided by operations	**1,009**	1,025	**3,674**	3,571
Investing activities				
Capital expenditures	**1,431**	1,040	**4,461**	2,595
Equity investments	**62**	95	**163**	652
Acquisitions	**62**	214	**216**	214
Dividends Declared				
per common share	**0.46**	0.44	**1.84**	1.76
per Series 1 preferred share	**0.29**	0.29	**1.15**	1.15
per Series 3 preferred share	**0.25**	0.25	**1.00**	1.00
per Series 5 preferred share	**0.28**	0.28	**1.10**	1.10
per Series 7 preferred share[1]	**0.25**	—	**0.91**	—
Basic common shares outstanding (millions)				
Average for the period	**707**	705	**707**	705
End of period	**707**	705	**707**	705

1 Issued March 4, 2013.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are forward-looking are based on certain assumptions and on what we know and expect today and generally include words like *anticipate, expect, believe, may, will, should, estimate* or other similar words.

Forward-looking statements in this news release may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this news release.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- foreign exchange rates
- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of our counterparties
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects

- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2012 Annual Report.

As actual results could vary significantly from forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TransCanada in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable depreciation and amortization
- comparable interest expense
- comparable interest income and other
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by GAAP and therefore are unlikely to be comparable to similar measures presented by other entities.

EBITDA and EBIT
We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting interest and other financial charges, income tax, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is an effective measure of our performance and an effective tool for evaluating trends in each segment. It is calculated in the same way as EBITDA, less depreciation and amortization.

Funds generated from operations
Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is an effective measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period.

Comparable measures
We calculate the comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable EBITDA	EBITDA
comparable EBIT	EBIT
comparable depreciation and amortization	depreciation and amortization
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income tax expense	income tax expense/(recovery)

Our decision not to include a specific item is subjective and made after careful consideration. These may include:

- 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
- impact of regulatory or arbitration decisions relating to prior year earnings
- write-downs of assets and investments.

We calculate comparable earnings by excluding the unrealized gains and losses from changes in fair value of certain derivatives used to reduce our exposure to certain financial commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

Reconciliation of non-GAAP measures

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2013**	**2012**	**2013**	**2012**
EBITDA	**1,320**	1,040	**4,958**	4,224
Non-comparable risk management activities affecting EBITDA	**(29)**	12	**(44)**	21
NEB decision - 2012	**—**	**—**	**(55)**	**—**
Comparable EBITDA	**1,291**	1,052	**4,859**	4,245
Comparable depreciation and amortization	**(396)**	(343)	**(1,472)**	(1,375)
Comparable EBIT	**895**	709	**3,387**	2,870
Other income statement items				
Comparable interest expense	**(240)**	(246)	**(984)**	(976)
Comparable interest income and other	**10**	20	**42**	86
Comparable income tax expense	**(198)**	(123)	**(662)**	(477)
Net income attributable to non-controlling interests	**(38)**	(28)	**(125)**	(118)
Preferred share dividends	**(19)**	(14)	**(74)**	(55)
Comparable earnings	**410**	318	**1,584**	1,330
Specific items (net of tax):				
NEB decision - 2012	**—**	—	**84**	—
Part VI.I income tax adjustment	**—**	—	**25**	—
Sundance A PPA arbitration decision - 2011	**—**	—	**—**	(15)
Risk management activities[1]	**10**	(12)	**19**	(16)
Net income attributable to common shares	**420**	306	**1,712**	1,299
Comparable depreciation and amortization	**(396)**	(343)	**(1,472)**	(1,375)
Specific item:				
NEB decision - 2012	**—**	—	**(13)**	—
Depreciation and amortization	**(396)**	(343)	**(1,485)**	(1,375)
Comparable interest expense	**(240)**	(246)	**(984)**	(976)
Specific item:				
NEB decision - 2012	**—**	—	**(1)**	—
Interest expense	**(240)**	(246)	**(985)**	(976)
Comparable interest income and other	**10**	20	**42**	86
Specific items:				
NEB decision - 2012	**—**	—	**1**	—
Risk management activities[1]	**(9)**	(5)	**(9)**	(1)
Interest income and other	**1**	15	**34**	85
Comparable income tax expense	**(198)**	(123)	**(662)**	(477)
Specific items:				
NEB decision - 2012	**—**	—	**42**	—
Part VI.I income tax adjustment	**—**	—	**25**	—
Income taxes attributable to Sundance A PPA arbitration decision - 2011	**—**	—	**—**	5
Risk management activities[1]	**(10)**	5	**(16)**	6
Income tax expense	**(208)**	(118)	**(611)**	(466)
Comparable earnings per common share	**$0.58**	$0.45	**$2.24**	$1.89
Specific items (net of tax):				
NEB decision - 2012	**—**	—	**0.12**	—
Part VI.I income tax adjustment	**—**	—	**0.04**	—
Sundance A PPA arbitration decision - 2011	**—**	—	**—**	(0.02)
Risk management activities[1]	**0.01**	(0.02)	**0.02**	(0.03)
Net income per common share	**$0.59**	$0.43	**$2.42**	$1.84

	three months ended December 31		year ended December 31	
1 **(unaudited - millions of $)**	**2013**	**2012**	**2013**	**2012**
Canadian Power	**(2)**	(6)	**(4)**	4
U.S. Power	**36**	(5)	**50**	(1)
Natural Gas Storage	**(5)**	(1)	**(2)**	(24)
Foreign exchange	**(9)**	(5)	**(9)**	(1)
Income tax attributable to risk management activities	**(10)**	5	**(16)**	6
Total gains/(losses) from risk management activities	**10**	(12)	**19**	(16)

Comparable EBITDA and Comparable EBIT by business segment

three months ended December 31, 2013 (unaudited - millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**778**	**198**	**346**	**(31)**	**1,291**
Comparable depreciation and amortization	**(280)**	**(38)**	**(74)**	**(4)**	**(396)**
Comparable EBIT	**498**	**160**	**272**	**(35)**	**895**

three months ended December 31, 2012 (unaudited - millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	690	172	222	(32)	1,052
Comparable depreciation and amortization	(236)	(36)	(68)	(3)	(343)
Comparable EBIT	454	136	154	(35)	709

year ended December 31, 2013 (unaudited - millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**2,852**	**752**	**1,363**	**(108)**	**4,859**
Comparable depreciation and amortization	**(1,013)**	**(149)**	**(294)**	**(16)**	**(1,472)**
Comparable EBIT	**1,839**	**603**	**1,069**	**(124)**	**3,387**

year ended December 31, 2012 (unaudited - millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	2,741	698	903	(97)	4,245
Comparable depreciation and amortization	(933)	(145)	(283)	(14)	(1,375)
Comparable EBIT	1,808	553	620	(111)	2,870

Results - Fourth quarter 2013

Net income attributable to common shares was $420 million this quarter compared to $306 million in fourth quarter 2012.

Comparable earnings this quarter were $92 million or $0.13 per share higher than fourth quarter 2012.

This was primarily the result of:

- higher equity income from Bruce Power reflecting incremental earnings from Unit 4 due to fewer planned outage days and return to service of Units 1 and 2
- higher earnings from the Canadian Mainline due to the higher rate of return on common equity (ROE) of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the NEB decision on the Canadian Mainline Restructuring Proposal (NEB decision)
- higher earnings from the NGTL System because of a higher average investment base associated with 2012 and 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013 which included a higher ROE and incentive earnings
- higher earnings from the Keystone Pipeline System primarily due to higher volumes.

These increases were partly offset by:

- lower contribution from U.S. natural gas pipelines due to lower transportation revenue at ANR as well as reduced earnings from GTN and Bison due to the reduction of our effective ownership from 83 per cent to 50 per cent, effective in July 2013
- lower earnings from Western Power primarily due to lower realized power prices.

Results - Annual

Comparable earnings in 2013 were $254 million higher than in 2012, an increase of $0.35 per share.

The increase in comparable earnings was the result of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4
- higher earnings from the Canadian Mainline reflecting a higher ROE of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the NEB decision
- higher earnings from U.S. Power because of higher capacity prices in New York and higher realized power prices
- higher earnings from the NGTL System reflecting a higher investment base and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013
- higher earnings from the Keystone Pipeline System primarily due to higher volumes
- higher earnings from Western Power because of higher purchased volumes under the power purchase arrangements (PPA).

These increases were partly offset by lower contributions from U.S. natural gas pipelines because of lower earnings contributions at ANR and Great Lakes.

Net income attributable to common shares was $1,712 million in 2013 compared to $1,299 million in 2012.

Net income includes comparable earnings discussed above as well as other specific items which are excluded from comparable earnings. The following specific items were recognized in net income in 2013 and 2012:

- $84 million of net income in 2013 related to 2012 from the NEB decision
- $25 million favourable tax adjustment in 2013 due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax
- $15 million after-tax charge ($20 million pre-tax) in 2012 related to the Sundance A PPA arbitration decision. This charge was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011
- the impact of certain risk management activities each year.

Natural Gas Pipelines

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	2013	2012	2013	2012
Canadian Pipelines				
Canadian Mainline	**305**	250	**1,121**	994
NGTL System	**261**	195	**846**	749
Foothills	**28**	30	**114**	120
Other Canadian (TQM[1], Ventures LP)	**6**	7	**26**	29
Canadian Pipelines - comparable EBITDA	**600**	482	**2,107**	1,892
Comparable depreciation and amortization	**(225)**	(182)	**(790)**	(715)
Canadian Pipelines - comparable EBIT	**375**	300	**1,317**	1,177
U.S. and International Pipelines (US$)				
ANR	**33**	63	**188**	254
GTN[2]	**11**	28	**76**	112
Great Lakes[3]	**10**	11	**34**	62
TC PipeLines, LP[1,4]	**21**	17	**72**	74
Other U.S. pipelines (Iroquois[1], Bison[2], Portland[5])	**26**	32	**107**	111
International (Gas Pacifico/INNERGY[1], Guadalajara[6], Tamazunchale, TransGas[1])	**25**	27	**106**	112
General, administrative and support costs	**(3)**	(4)	**(10)**	(8)
Non-controlling interests[7]	**60**	39	**186**	161
U.S. and International Pipelines - comparable EBITDA	**183**	213	**759**	878
Comparable depreciation and amortization	**(53)**	(54)	**(217)**	(218)
U.S. and International Pipelines - comparable EBIT	**130**	159	**542**	660
Foreign exchange impact	**7**	(1)	**15**	—
U.S. and International Pipelines - comparable EBIT (Cdn$)	**137**	158	**557**	660
Business Development comparable EBITDA and EBIT	**(14)**	(4)	**(35)**	(29)
Natural Gas Pipelines - comparable EBIT	**498**	454	**1,839**	1,808
Summary				
Natural Gas Pipelines - comparable EBITDA	**778**	690	**2,852**	2,741
Comparable depreciation and amortization	**(280)**	(236)	**(1,013)**	(933)
Natural Gas Pipelines - comparable EBIT	**498**	454	**1,839**	1,808

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.

2 Effective July 1, 2013, represents our 30 per cent direct ownership interest. Prior to July 1, 2013, our direct ownership interest was 75 per cent.

3 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.

4 Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. The following table shows our ownership interest in TC PipeLines,LP and our ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of		
	July 1, 2013	May 22, 2013	January 1, 2012
TC PipeLines, LP	28.9	28.9	33.3
Effective ownership through TC PipeLines, LP:			
GTN/Bison	20.2	7.2	8.3
Great Lakes	13.4	13.4	15.5

5 Represents our 61.7 per cent ownership interest.

6 Included as of June 2011.

7 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	2013	2012	2013	2012
Canadian Mainline - net income	**76**	47	**361**	187
Canadian Mainline - comparable earnings	**76**	47	**277**	187
NGTL System	**72**	55	**243**	208
Foothills	**5**	4	**18**	19

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

year ended December 31	Canadian Mainline[1]		NGTL System[2]		ANR[3]	
(unaudited)	2013	2012	2013	2012	2013	2012
Average investment base (millions of $)	**5,841**	5,737	**5,938**	5,501	**n/a**	n/a
Delivery volumes (Bcf):						
Total	**1,339**	1,551	**3,683**	3,645	**1,566**	1,620
Average per day	**3.7**	4.2	**10.1**	10.0	**4.3**	4.4

1 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the twelve months ended December 31, 2013 were 803 Bcf (2012 – 859 Bcf). Average per day was 2.2 Bcf (2012 – 2.3 Bcf).

2 Field receipt volumes for the NGTL System for the twelve months ended December 31, 2013 were 3,680 Bcf (2012 – 3,660 Bcf). Average per day was 10.1 Bcf (2012 – 10.0 Bcf).

3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

CANADIAN PIPELINES

Comparable EBITDA and net income for our rate-regulated Canadian Pipelines are primarily affected by our approved ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA and EBIT but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

Canadian Mainline's comparable earnings increased by $29 million for the three months ended December 31, 2013 compared to the same period in 2012 because of the impact of the NEB decision. Among other items, the NEB approved an ROE of 11.50 per cent on 40 per cent deemed common equity for the years 2012 through to 2017 compared to the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent that was used to record earnings in 2012, as well as an incentive mechanism based on total net revenues. The increase in comparable earnings is mainly due to the higher ROE plus incentive earnings.

Net income for the NGTL System increased by $17 million for the three months ended December 31, 2013 compared to the same period in 2012 because of the impact of the 2013-2014 NGTL Settlement which included higher ROE and incentive earnings and a higher average investment base associated with 2012 and 2013 capital expenditures. The 2013-2014 NGTL Settlement, approved by the NEB in November 2013, included an ROE of 10.10 per cent on 40 per cent deemed common equity compared to an ROE of 9.70 per cent on 40 per cent deemed common equity in 2012. The 2013-2014 NGTL Settlement also included annual fixed amounts for certain OM&A costs.

U.S. PIPELINES AND INTERNATIONAL

EBITDA for our U.S. operations is generally affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services, including OM&A and property taxes.

ANR is also affected by the level of contracting and the determination of rates driven by the market value of our services for its storage capacity, storage related transportation services, and incidental commodity sales. ANR's pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of its business.

Comparable EBITDA for the U.S. and International Pipelines decreased US$30 million for the three months ended December 31, 2013 compared to the same period in 2012. This was the net effect of:

- lower transportation and storage revenues at ANR
- higher OM&A and costs relating to services provided by other pipelines at ANR
- lower contributions from GTN and Bison as a result of a reduction of our effective ownership in each pipeline from 83 per cent in 2012 to 50 per cent, effective July 1, 2013
- higher contributions from Portland due to higher short term revenues.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased $44 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to a 2013 true-up for the higher composite depreciation rate in the 2013-2014 NGTL Settlement approved in November 2013, higher investment base on the NGTL System, and the impact of the NEB decision.

Oil Pipelines

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Keystone Pipeline System	**200**	180	**766**	712
Oil Pipelines Business Development	**(2)**	(8)	**(14)**	(14)
Oil Pipelines - comparable EBITDA	**198**	172	**752**	698
Comparable depreciation and amortization	**(38)**	(36)	**(149)**	(145)
Oil Pipelines - comparable EBIT	**160**	136	**603**	553
Comparable EBIT denominated as follows:				
Canadian dollars	**53**	44	**201**	191
U.S. dollars	**102**	94	**389**	363
Foreign exchange impact	**5**	(2)	**13**	(1)
	160	136	**603**	553

Comparable EBITDA from our Keystone Pipeline System is generated primarily by providing pipeline capacity to shippers in exchange for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis and provides opportunities to generate incremental earnings.

Comparable EBITDA for the Keystone Pipeline System increased by $20 million for the three months ended December 31, 2013 compared to the same period in 2012, primarily because of higher volumes.

BUSINESS DEVELOPMENT

Business development expenses for the three months ended December 31, 2013 were $6 million lower than the same period in 2012 due to greater capitalization of oil pipeline development project costs in fourth quarter 2013.

Energy

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2013	2012	2013	2012
Canadian Power				
Western Power	**60**	84	**380**	335
Eastern Power[1]	**99**	94	**347**	345
Bruce Power	**115**	(8)	**310**	14
General, administrative and support costs	**(17)**	(14)	**(50)**	(48)
Canadian Power - comparable EBITDA[2]	**257**	156	**987**	646
Comparable depreciation and amortization	**(43)**	(35)	**(172)**	(152)
Canadian Power - comparable EBIT[2]	**214**	121	**815**	494
U.S. Power (US$)				
Northeast Power	**79**	62	**370**	257
General, administrative and support costs	**(14)**	(14)	**(47)**	(48)
U.S. Power - comparable EBITDA	**65**	48	**323**	209
Comparable depreciation and amortization	**(27)**	(31)	**(107)**	(121)
U.S. Power - comparable EBIT	**38**	17	**216**	88
Foreign exchange impact	**2**	—	**7**	—
U.S. Power - comparable EBIT (Cdn$)	**40**	17	**223**	88
Natural Gas Storage and other				
Natural Gas Storage and other	**30**	23	**73**	77
General, administrative and support costs	**(3)**	(3)	**(10)**	(10)
Natural Gas Storage and other - comparable EBITDA[2]	**27**	20	**63**	67
Comparable depreciation and amortization	**(3)**	(2)	**(12)**	(10)
Natural Gas Storage and other- comparable EBIT[2]	**24**	18	**51**	57
Business Development comparable EBITDA and EBIT	**(6)**	(2)	**(20)**	(19)
Energy - comparable EBIT[2]	**272**	154	**1,069**	620
Summary				
Energy - comparable EBITDA[2]	**346**	222	**1,363**	903
Comparable depreciation and amortization	**(74)**	(68)	**(294)**	(283)
Energy - comparable EBIT[2]	**272**	154	**1,069**	620

1 Includes the acquisition of four Ontario Solar facilities in 2013 and Cartier phase two of Gros-Morne starting in November 2012.

2 Includes our share of equity income from our equity accounted for investments in ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta up to December 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent and commenced consolidating their operations.

Comparable EBITDA for Energy increased by $124 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was the net effect of:

- higher equity income from Bruce Power mainly because of incremental earnings from Unit 4 due to fewer planned outage days and the return to service of Units 1 and 2
- higher earnings from U.S. Power mainly because of higher capacity prices in New York offset by lower volumes, primarily at the Ravenswood facility
- lower earnings from Western Power mainly because of lower realized power prices partly offset by the return to service of Sundance A Unit 1 in early September 2013 and Unit 2 in early October 2013.

CANADIAN POWER

Western and Eastern Power[1]

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2013	**2012**	**2013**	**2012**
Revenue				
Western Power	**168**	158	**609**	640
Eastern Power[1]	**104**	106	**400**	415
Other[2]	**34**	25	**108**	91
	306	289	**1,117**	1,146
Income from equity investments[3]	**15**	23	**141**	68
Commodity purchases resold				
Western power	**(92)**	(74)	**(277)**	(281)
Other[4]	**(2)**	(2)	**(6)**	(5)
	(94)	(76)	**(283)**	(286)
Plant operating costs and other	**(68)**	(58)	**(248)**	(218)
Sundance A PPA arbitration decision - 2012	**—**	—	**—**	(30)
General, administrative and support costs	**(17)**	(14)	**(50)**	(48)
Comparable EBITDA	**142**	164	**677**	632
Comparable depreciation and amortization	**(43)**	(35)	**(172)**	(152)
Comparable EBIT	**99**	129	**505**	480
Breakdown of comparable EBITDA				
Western Power	**60**	84	**380**	335
Eastern Power	**99**	94	**347**	345
General, administrative and support costs	**(17)**	(14)	**(50)**	(48)
Comparable EBITDA	**142**	**164**	**677**	**632**

1 Includes the acquisition of four Ontario Solar facilities in 2013 and Cartier phase two of Gros-Morne starting in November 2012.

2 Includes sale of excess natural gas purchased for generation and sales of thermal carbon black.

3 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.

4 Includes the cost of excess natural gas not used in operations.

Sales volumes and plant availability[1,2]

Includes our share of volumes from our equity investments.

(unaudited)	three months ended December 31 2013	2012	year ended December 31 2013	2012
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**691**	714	**2,728**	2,691
Eastern Power[1]	**854**	908	**3,822**	4,384
Purchased				
Sundance A & B and Sheerness PPAs[2]	**2,771**	2,017	**8,223**	6,906
Other purchases	**12**	—	**13**	46
	4,328	3,639	**14,786**	14,027
Sales				
Contracted				
Western Power	**2,372**	2,192	**7,864**	8,240
Eastern Power[1]	**854**	908	**3,822**	4,384
Spot				
Western Power	**1,102**	539	**3,100**	1,403
	4,328	3,639	**14,786**	14,027
Plant availability[3]				
Western Power[4]	**96%**	97%	**95%**	96%
Eastern Power[1,5]	**90%**	93%	**90%**	90%

1 Includes the acquisition of four Ontario Solar facilities in 2013 and Cartier phase two of Gros-Morne starting in November 2012.

2 Includes our 50 per cent ownership of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in early September 2013 and Unit 2 returned to service in early October 2013.

3 The percentage of time in a period that the plant is available to generate power, regardless of whether it is running.

4 Does not include facilities that provide power to us under PPAs.

5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA decreased by $24 million for the three months ended December 31, 2013 compared to the same period in 2012 due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of Sundance A Unit 1 in early September 2013 and Unit 2 in early October 2013.

Average spot market power prices in Alberta decreased by 39 per cent to $48 per MWh for the three months ended December 31, 2013 compared to the same period in 2012. This decrease was the result of changes in the Alberta power supply and demand balance reflecting the return of Sundance A Units 1 and 2, significantly fewer coal plant outages and higher wind output in fourth quarter 2013 compared to fourth quarter 2012. Realized power prices on power sales can be higher or lower than spot market power prices in any given period, as a result of contracting activities.

Approximately 68 per cent of Western Power sales volumes were sold under contract this quarter compared to 80 per cent in fourth quarter 2012. To reduce exposure to spot market prices in Alberta, Western Power enters into fixed price forward sales to secure future revenue and a portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium and large industrial and commercial companies and other market participants and will affect our average realized price (versus spot price) in future periods.

Eastern Power

Eastern Power's comparable EBITDA increased by $5 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to higher earnings at Bécancour and the acquisition of four Ontario Solar facilities in 2013.

BRUCE POWER

Our proportionate share.

	three months ended December 31		year ended December 31	
(unaudited - millions of $ unless noted otherwise)	2013	2012	2013	2012
Income/(loss) from equity investments[1]				
Bruce A	**70**	(54)	**202**	(149)
Bruce B	**45**	46	**108**	163
	115	(8)	**310**	14
Comprised of:				
Revenues	**342**	228	**1,258**	763
Operating expenses	**(145)**	(165)	**(618)**	(567)
Depreciation and other	**(82)**	(71)	**(330)**	(182)
	115	(8)	**310**	14
Bruce Power - Other information				
Plant availability[2]				
Bruce A[3]	**90%**	52%	**82%**	54%
Bruce B	**98%**	100%	**89%**	95%
Combined Bruce Power	**94%**	79%	**86%**	81%
Planned outage days				
Bruce A	**—**	123	**123**	336
Bruce B	**—**	—	**140**	46
Unplanned outage days				
Bruce A	**18**	11	**63**	18
Bruce B	**7**	—	**20**	25
Sales volumes (GWh)[1]				
Bruce A[3]	**2,907**	1,609	**10,033**	4,194
Bruce B	**2,177**	2,278	**7,824**	8,475
	5,084	3,887	**17,857**	12,669
Realized sales price per MWh[4]				
Bruce A	**$71**	$68	**$70**	$68
Bruce B	**$54**	$54	**$54**	$55
Combined Bruce Power	**$62**	$57	**$62**	$57

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes exclude deemed generation.

2 The percentage of time the plant was available to generate power, regardless of whether it was running.

3 Plant availability and sales volumes for 2013 and 2012 include the incremental impact of Units 1 and 2 which were returned to service in October 2012.

4 Calculated based on actual and deemed generation. Bruce B realized sales prices per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Equity income from Bruce A increased by $124 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was mainly due to:

- incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013
- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher realized prices.

Under the contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh. The fixed price is adjusted annually on April 1 for inflation and other provisions under the OPA contract. Bruce A also recovers fuel costs from the OPA.

Bruce A Fixed price	Per MWh
April 1, 2013 - March 31, 2014	$70.99
April 1, 2012 - March 31, 2013	$68.23
April 1, 2011 - March 31, 2012	$66.33

Under the same contract, all output from Bruce B is subject to a floor price adjusted annually for inflation on April 1.

Bruce B Floor price	Per MWh
April 1, 2013 - March 31, 2014	$52.34
April 1, 2012 - March 31, 2013	$51.62
April 1, 2011 - March 31, 2012	$50.18

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. Bruce Power has not had to repay any amounts in the past three years.

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

The overall plant availability percentage in 2014 is expected to be in the high 80s for both Bruce A and Bruce B. Planned maintenance on a Bruce A unit is scheduled to occur in the first half of 2014. Planned maintenance on two Bruce B units is scheduled to occur in first and fourth quarters 2014.

U.S. POWER

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended December 31		year ended December 31	
(unaudited - millions of US$)	**2013**	**2012**	**2013**	**2012**
Revenue				
Power[1]	**333**	353	**1,484**	1,189
Capacity	**78**	53	**295**	234
Other[2]	**5**	22	**56**	51
	416	428	**1,835**	1,474
Commodity purchases resold	**(251)**	(217)	**(1,003)**	(765)
Plant operating costs and other[2]	**(86)**	(149)	**(462)**	(452)
General, administrative and support costs	**(14)**	(14)	**(47)**	(48)
Comparable EBITDA	**65**	48	**323**	209
Comparable depreciation and amortization	**(27)**	(31)	**(107)**	(121)
Comparable EBIT	**38**	17	**216**	88

1 The realized gains and losses from financial derivatives used to buy and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in power revenues.

2 Includes revenues and costs related to a third party service agreement at Ravenswood.

Sales volumes and plant availability

(unaudited)	three months ended December 31 2013	2012	year ended December 31 2013	2012
Physical sales volumes (GWh)				
Supply				
Generation	**1,152**	2,276	**6,173**	7,567
Purchased	**2,259**	2,550	**9,001**	9,408
	3,411	4,826	**15,174**	16,975
Plant availability[1, 2]	**71%**	81%	**84%**	85%

1 The percentage of time the plant was available to generate power, regardless of whether it was running.

2 Plant availability decreased in the three months ended December 31, 2013 due to the impact of planned outages at Ravenswood.

U.S. Power's comparable EBITDA was US$17 million higher for the three months ended December 31, 2013 compared to the same period in 2012. The increase was the net effect of:

- higher realized capacity prices in New York
- higher realized power prices in New England offset by the impact of higher fuel costs
- lower generation, primarily at the Ravenswood facility.

Spot capacity prices in New York City were approximately 91 per cent higher in fourth quarter 2013 compared to the same period in 2012. This increase in spot capacity prices and the impact of hedging activities resulted in higher realized prices in New York.

Commodity prices in U.S. Power were higher in 2013 as natural gas prices recovered from low levels in 2012. Higher natural gas prices and fuel transportation constraints in the Northeast United States were factors that contributed to ISO power prices in New England increasing by approximately 33 per cent in fourth quarter 2013 compared to the same period in 2012. Revenue, commodity purchases resold, and plant operating costs and other, which includes fuel gas consumed in generation, were impacted by this increase in commodity prices.

Physical sales volumes in the three months ended December 31, 2013 decreased compared to the same period in 2012. Generation volumes decreased primarily due to lower generation at the Ravenswood facility in fourth quarter 2013 compared to fourth quarter 2012, when Ravenswood ran at higher than normal levels during and following Superstorm Sandy when damage at several other power and transmission facilities reduced power supply in New York City. Purchased volumes were lower in fourth quarter 2013 compared to the same period in 2012 as volumes purchased to serve the commercial and industrial customers in the New England market decreased, partially offset by higher volumes in the PJM market. Both Revenue and Plant operating costs and other were impacted by these lower volumes.

As at December 31, 2013, approximately 4,300 GWh or 53 per cent of U.S. Power's planned generation is contracted for 2014, and 1,800 GWh or 24 per cent for 2015. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2013	**2012**	**2013**	**2012**
Natural Gas Storage and other[1]	**30**	23	**73**	77
General, administrative and support costs	**(3)**	(3)	**(10)**	(10)
Comparable EBITDA	**27**	20	**63**	67
Comparable depreciation and amortization	**(3)**	(2)	**(12)**	(10)
Comparable EBIT	**24**	18	**51**	57

1 Includes our share of equity income from our investment in CrossAlta up to December 18, 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent and commenced consolidating their operations.

Comparable EBITDA increased by $7 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to higher volumes at higher realized natural gas storage spreads and incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

Other income statement items

(unaudited - millions of $)	three months ended December 31 2013	three months ended December 31 2012	year ended December 31 2013	year ended December 31 2012
Comparable interest expense	**240**	246	**984**	976
Comparable interest income and other	**(10)**	(20)	**(42)**	(86)
Comparable income tax expense	**198**	123	**662**	477
Net income attributable to non-controlling interests	**38**	28	**125**	118

(unaudited - millions of $)	three months ended December 31 2013	three months ended December 31 2012	year ended December 31 2013	year ended December 31 2012
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian dollar-denominated	**123**	128	**495**	513
U.S. dollar-denominated (US$)	**205**	186	**766**	740
Foreign exchange	**7**	(1)	**20**	—
	335	313	**1,281**	1,253
Other interest and amortization (recovery)/ expense	**(3)**	9	**(10)**	23
Capitalized interest	**(92)**	(76)	**(287)**	(300)
Comparable interest expense	**240**	246	**984**	976

Comparable interest expense was $6 million lower for the three months ended December 31, 2013 compared to the same period in 2012 because of:

- higher capitalized interest primarily for the Gulf Coast project and Mexican projects partially offset by the refurbished units at Bruce Power being placed in service
- higher interest expense due to debt issues of US$1.25 billion in October 2013, US$500 million in July 2013, $750 million in July 2013, US$750 million in January 2013, a TC Pipelines, LP debt issue of US$500 million in July 2013 and higher foreign exchange on interest expense related to U.S. denominated debt, partially offset by Canadian and U.S. dollar-denominated debt maturities.

Comparable income tax expense was $75 million higher for the three months ended December 31, 2013 compared to the same period in 2012. The increase was mainly the result of higher pre-tax earnings in 2013 compared to 2012 combined with changes in the proportion of income earned between Canadian and foreign jurisdictions.

Net income attributable to non-controlling interests was $10 million higher for the three months ended December 31, 2013 compared to the same period in 2012. The increase is because of the sale of a 45 percent interest in each of GTN LLC and Bison to TC PipeLines, LP in July 2013.

Condensed consolidated statement of income

(unaudited - millions of Canadian $ except per share amounts)	three months ended December 31		year ended December 31	
	2013	2012	2013	2012
Revenues				
Natural gas pipelines	**1,226**	1,087	**4,497**	4,264
Oil pipelines	**294**	270	**1,124**	1,039
Energy	**812**	732	**3,176**	2,704
	2,332	2,089	**8,797**	8,007
Income from Equity Investments	**174**	61	**597**	257
Operating and Other Expenses				
Plant operating costs and other	**735**	731	**2,674**	2,577
Commodity purchases resold	**359**	291	**1,317**	1,049
Property taxes	**92**	88	**445**	434
Depreciation and amortization	**396**	343	**1,485**	1,375
	1,582	1,453	**5,921**	5,435
Financial Charges/(Income)				
Interest expense	**240**	246	**985**	976
Interest income and other	**(1)**	(15)	**(34)**	(85)
	239	231	**951**	891
Income before Income Taxes	**685**	466	**2,522**	1,938
Income Tax Expense				
Current	**3**	80	**43**	181
Deferred	**205**	38	**568**	285
	208	118	**611**	466
Net Income	**477**	348	**1,911**	1,472
Net income attributable to non-controlling interests	**38**	28	**125**	118
Net Income Attributable to Controlling Interests	**439**	320	**1,786**	1,354
Preferred share dividends	**19**	14	**74**	55
Net Income Attributable to Common Shares	**420**	306	**1,712**	1,299
Net Income per Common Share				
Basic and diluted	**$0.59**	$0.43	**$2.42**	$1.84
Dividends Declared per Common Share	**$0.46**	$0.44	**$1.84**	$1.76
Weighted Average Number of Common Shares (millions)				
Basic	**707**	705	**707**	705
Diluted	**708**	705	**708**	706

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended December 31		year ended December 31	
	2013	**2012**	**2013**	**2012**
Cash Generated from Operations				
Net income	**477**	348	**1,911**	1,472
Depreciation and amortization	**396**	343	**1,485**	1,375
Deferred income taxes	**205**	38	**568**	285
Income from equity investments	**(174)**	(61)	**(597)**	(257)
Distributed earnings received from equity investments	**178**	124	**605**	376
Employee post-retirement benefits funding lower than expense	**17**	22	**50**	9
Other	**(16)**	4	**(22)**	24
(Increase)/decrease in operating working capital	**(74)**	207	**(326)**	287
Net cash provided by operations	**1,009**	1,025	**3,674**	3,571
Investing Activities				
Capital expenditures	**(1,431)**	(1,040)	**(4,461)**	(2,595)
Equity investments	**(62)**	(95)	**(163)**	(652)
Acquisitions, net of cash acquired	**(62)**	(214)	**(216)**	(214)
Deferred amounts and other	**(13)**	123	**(280)**	205
Net cash used in investing activities	**(1,568)**	(1,226)	**(5,120)**	(3,256)
Financing Activities				
Dividends on common and preferred shares	**(344)**	(325)	**(1,356)**	(1,281)
Distributions paid to non-controlling interests	**(52)**	(34)	**(166)**	(135)
Notes payable issued/(repaid), net	**126**	790	**(492)**	449
Long-term debt issued, net of issue costs	**1,336**	3	**4,253**	1,491
Repayment of long-term debt	**(56)**	(198)	**(1,286)**	(980)
Common shares issued	**13**	18	**72**	53
Preferred shares issued, net of issue costs	**—**	—	**585**	—
Partnership units of subsidiary issued, net of issue costs	**—**	—	**384**	—
Preferred shares of subsidiary redeemed	**(200)**	—	**(200)**	—
Net cash provided by/(used in) financing activities	**823**	254	**1,794**	(403)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**18**	4	**28**	(15)
Increase/(Decrease) in Cash and Cash Equivalents	**282**	57	**376**	(103)
Cash and Cash Equivalents				
Beginning of period	**645**	494	**551**	654
Cash and Cash Equivalents				
End of period	**927**	551	**927**	551

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)	December 31 2013	December 31 2012
ASSETS		
Current Assets		
Cash and cash equivalents	**927**	551
Accounts receivable	**1,122**	1,052
Inventories	**251**	224
Other	**847**	997
	3,147	2,824
Plant, Property and Equipment, net of accumulated depreciation of $17,851 and $16,540, respectively	**37,606**	33,713
Equity Investments	**5,759**	5,366
Regulatory Assets	**1,735**	1,629
Goodwill	**3,696**	3,458
Intangible and Other Assets	**1,955**	1,406
	53,898	48,396
LIABILITIES		
Current Liabilities		
Notes payable	**1,842**	2,275
Accounts payable and other	**2,155**	2,344
Accrued interest	**388**	368
Current portion of long-term debt	**973**	894
	5,358	5,881
Regulatory Liabilities	**229**	268
Other Long-Term Liabilities	**656**	882
Deferred Income Tax Liabilities	**4,564**	4,016
Long-Term Debt	**21,892**	18,019
Junior Subordinated Notes	**1,063**	994
	33,762	30,060
EQUITY		
Common shares, no par value	**12,149**	12,069
Issued and outstanding: December 31, 2013 - 707 million shares		
December 31, 2012 - 705 million shares		
Preferred shares	**1,813**	1,224
Additional paid-in capital	**401**	379
Retained earnings	**5,096**	4,687
Accumulated other comprehensive loss	**(934)**	(1,448)
Controlling Interests	**18,525**	16,911
Non-controlling interests	**1,611**	1,425
	20,136	18,336
	53,898	48,396

Segmented Information

three months ended December 31	Natural Gas Pipelines		Oil Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
Revenues	**1,226**	1,087	**294**	270	**812**	732	**—**	—	**2,332**	2,089
Income from equity investments	**40**	37	**—**	—	**134**	24	**—**	—	**174**	61
Plant operating costs and other	**(423)**	(373)	**(86)**	(88)	**(195)**	(238)	**(31)**	(32)	**(735)**	(731)
Commodity purchases resold	**—**	—	**—**	—	**(359)**	(291)	**—**	—	**(359)**	(291)
Property taxes	**(65)**	(61)	**(10)**	(10)	**(17)**	(17)	**—**	—	**(92)**	(88)
Depreciation and amortization	**(280)**	(236)	**(38)**	(36)	**(74)**	(68)	**(4)**	(3)	**(396)**	(343)
	498	454	**160**	136	**301**	142	**(35)**	(35)	**924**	697
Interest expense									**(240)**	(246)
Interest income and other									**1**	15
Income before income taxes									**685**	466
Income tax expense									**(208)**	(118)
Net Income									**477**	348
Net Income Attributable to Non-Controlling Interests									**(38)**	(28)
Net Income Attributable to Controlling Interests									**439**	320
Preferred Share Dividends									**(19)**	(14)
Net Income Attributable to Common Shares									**420**	306

year ended December 31	Natural Gas Pipelines		Oil Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
Revenues	**4,497**	4,264	**1,124**	1,039	**3,176**	2,704	**—**	—	**8,797**	8,007
Income from equity investments	**145**	157	**—**	—	**452**	100	**—**	—	**597**	257
Plant operating costs and other	**(1,405)**	(1,365)	**(328)**	(296)	**(833)**	(819)	**(108)**	(97)	**(2,674)**	(2,577)
Commodity purchases resold	**—**	—	**—**	—	**(1,317)**	(1,049)	**—**	—	**(1,317)**	(1,049)
Property taxes	**(329)**	(315)	**(44)**	(45)	**(72)**	(74)	**—**	—	**(445)**	(434)
Depreciation and amortization	**(1,027)**	(933)	**(149)**	(145)	**(293)**	(283)	**(16)**	(14)	**(1,485)**	(1,375)
	1,881	1,808	**603**	553	**1,113**	579	**(124)**	(111)	**3,473**	2,829
Interest expense									**(985)**	(976)
Interest income and other									**34**	85
Income before income taxes									**2,522**	1,938
Income tax expense									**(611)**	(466)
Net Income									**1,911**	1,472
Net Income Attributable to Non-Controlling Interests									**(125)**	(118)
Net Income Attributable to Controlling Interests									**1,786**	1,354
Preferred Share Dividends									**(74)**	(55)
Net Income Attributable to Common Shares									**1,712**	1,299