SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16 of
the Securities Exchange Act of 1934

For the month of January 2016
Commission File No. 1-31690

TransCanada Corporation

(Translation of Registrant's Name into English)

450 – 1 Street S.W., Calgary, Alberta, T2P 5H1, Canada
(Address of Principal Executive Offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F:

Form 20-F ☐ Form 40-F ☑

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): ☐

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ☐

Exhibit 99.1 to this report, furnished on Form 6-K, is furnished, not filed, and will not be incorporated by reference into any registration statement filed by the registrant under the Securities Act of 1933, as amended.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: January 29, 2016

TRANSCANADA CORPORATION

By: /s/ Christine R. Johnston
Christine R. Johnston
Vice-President, Law and Corporate Secretary

EXHIBIT INDEX

99.1	A copy of the registrant’s News Release dated January 29, 2016.

NewsRelease

TransCanada
In business to deliver

TransCanada Reports Fourth Quarter and Year-End 2015 Financial Results
Common Share Dividend Increased Nine Per Cent to $2.26 Per Share Annually

CALGARY, Alberta – **February 11, 2016** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced a net loss attributable to common shares for fourth quarter 2015 of $2.5 billion or $3.47 per share compared to net income of $458 million or $0.65 per share for the same period in 2014. For the year ended December 31, 2015, the net loss attributable to common shares was $1.2 billion or $1.75 per share compared to net income of $1.7 billion or $2.46 per share in 2014. Comparable earnings for fourth quarter 2015 were $453 million or $0.64 per share compared to $511 million or $0.72 per share for the same period last year. For the year ended December 31, 2015, comparable earnings were $1.8 billion or $2.48 per share compared to $1.7 billion or $2.42 per share in 2014. TransCanada's Board of Directors also declared a quarterly dividend of $0.565 per common share for the quarter ending March 31, 2016, equivalent to $2.26 per common share on an annualized basis, an increase of nine per cent. This is the sixteenth consecutive year the Board of Directors has raised the dividend.

“Although 2015 was a very challenging year for the energy industry, our $64 billion portfolio of high-quality energy infrastructure assets performed well," said Russ Girling, TransCanada’s president and chief executive officer. “Excluding specific items, comparable earnings and funds generated from operations reached record levels while we continued to safely and reliably meet the needs of our customers across North America.”

While we were extremely disappointed by the denial of a Presidential Permit for Keystone XL and the resulting $2.9 billion after-tax non-cash impairment charge, we are well positioned to continue to grow earnings and cash flow in the years ahead. Our assets are largely underpinned by cost of service regulated business models or long-term contracts with solid counterparties resulting in highly predictable cash flow streams with minimal commodity or volume throughput risk. In addition, we are proceeding with $13 billion of near-term growth opportunities that are expected to be in-service by 2018. Over the medium to longer-term we are advancing $45 billion of commercially secured, large-scale projects and various other initiatives that will create significant additional shareholder value.

“Based on the confidence we have in our future outlook, we recently repurchased 7.1 million common shares and are pleased to announce a nine per cent increase in the common share dividend,” added Girling. “Building upon the resiliency of our base business, our visible, near-term growth and our financial strength, our common share dividend is expected to rise at an average annual rate of eight to ten per cent through 2020. Success in advancing additional initiatives could further extend and augment future dividend growth.”

Fourth Quarter and Year-End Highlights

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

- Fourth quarter 2015 financial results:
  - Net loss attributable to common shares of $2.5 billion or $3.47 per share
  - Comparable earnings of $453 million or $0.64 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.5 billion
  - Funds generated from operations of $1.2 billion
  - Comparable distributable cash flow of $778 million or $1.10 per share
- For the year ended December 31, 2015:
  - Net loss attributable to common shares of $1.2 billion or $1.75 per share
  - Comparable earnings of $1.8 billion or $2.48 per share
  - Comparable EBITDA of $5.9 billion
  - Funds generated from operations of $4.5 billion
  - Comparable distributable cash flow of $3.5 billion or $5.00 per share

- Announced an increase in the quarterly common share dividend of nine per cent to $0.565 per common share for the quarter ending March 31, 2016
- Filed a normal course issuer bid to allow for the repurchase of up to 21.3 million common shares by November 22, 2016 and repurchased 7.1 million common shares for $307 million under this program as of February 10, 2016
- Acquired an additional interest in Bruce Power for $236 million, bringing our interest to 48.5 per cent
- Announced the Bruce Power Life Extension Agreement that will extend the operating life of the facility to 2064. TransCanada's estimated share of the capital investment over the life of the agreement is $6.5 billion (2014 dollars)
- Awarded a contract to build the US$500 million Tuxpan-Tula Pipeline in Mexico
- Announced the NGTL System reached a two-year revenue agreement with customers for 2016-2017 and signed contracts that will require a further expansion of approximately $600 million for 2018
- Sold a 49.9 per cent interest in Portland Natural Gas Transmission System (PNGTS) to TC PipeLines, LP for US$223 million
- Amended the application to the National Energy Board (NEB) for the Energy East Pipeline to reflect an adjusted route, schedule and capital cost
- Commenced legal actions following the U.S. Administration's denial of a Presidential Permit for the Keystone XL pipeline

Net income attributable to common shares decreased by $2.9 billion to a net loss of $2.5 billion or $3.47 per share for the three months ended December 31, 2015 compared to the same period last year. Fourth quarter 2015 included a net loss of $2.9 billion related to specific items including a $2.9 billion after-tax impairment charge related to Keystone XL, an $86 million after-tax loss provision related to the sale of TC Offshore, a $43 million after-tax charge related to an impairment of turbine equipment held for future use in Energy, a debt retirement charge of $27 million after-tax related to the merger of Bruce A and Bruce B, a $60 million after-tax charge for our business restructuring and transformation initiative and a positive $199 million adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes. Fourth quarter 2014 included an $8 million after-tax gain from the sale of Gas Pacifico/INNERGY. Both periods included unrealized gains and losses from changes in risk management activities. All of these specific items are excluded from comparable earnings.

Net loss attributable to common shares for the year ended December 31, 2015 was $1.2 billion or $1.75 per share compared to net income of $1.7 billion or $2.46 per share in 2014. Results in 2015 included a net loss of $3.0 billion related to specific items including those noted above for the fourth quarter as well as an Alberta corporate income tax rate increase of $34 million. Results in 2014 included a net after-tax gain of $99 million from the sale of Cancarb and its related power generation facility, an after-tax $32 million expense for terminating a natural gas storage contract and an $8 million after-tax gain from the sale of Gas Pacifico/INNERGY. These amounts, along with unrealized gains and losses on risk management activities, were excluded from comparable earnings.

Comparable earnings for fourth quarter 2015 were $453 million or $0.64 per share compared to $511 million or $0.72 per share for the same period in 2014. Lower contributions from Canadian Power and the Canadian Mainline were partially offset by higher earnings from the Keystone System.

Comparable earnings for the year ended December 31, 2015 were $1.8 billion or $2.48 per share compared to $1.7 billion or $2.42 per share in 2014. Higher earnings from the Keystone System, U.S. Power, ANR, Eastern Power and Mexico were partially offset by lower contributions from Western Power and Bruce Power.

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

Natural Gas Pipelines:

- *NGTL System:* In 2015, we placed approximately $350 million of facilities into service. Looking forward, the NGTL System continues to develop a further approximately $7.3 billion of new supply and demand facilities. We have approximately $2.3 billion of facilities that have received regulatory approval of which approximately $450 million are currently under construction. We have filed for approval for a further approximately $2.0 billion of facilities and are waiting for the regulatory review process. Applications for approval to construct and operate an additional $3.0 billion of facilities have yet to be filed.

  Included in our capital program is the recently announced 2018 expansion of a further $600 million of facilities required on the NGTL System. The 2018 expansion includes multiple projects totaling approximately 88 kilometres (km) (55 miles) of 20- to 48-inch diameter pipeline, one new compressor, approximately 35 new and expanded meter stations and other associated facilities. Applications to construct and operate the various components of the 2018 expansion program will be filed with the NEB between second quarter and fourth quarter 2016. Subject to regulatory approvals, construction is expected to start in 2017, with all facilities expected to be in service in 2018.

- *NGTL System Revenue Requirement Agreement:* In December, we reached a two-year revenue requirement agreement with customers and other interested parties on the annual costs, including return on equity and depreciation, required to operate the NGTL System for 2016 and 2017. The agreement fixes the equity return at 10.1 per cent on 40 per cent deemed common equity, establishes depreciation at a forecast composite rate of 3.16 per cent and fixes operating, maintenance and administration (OM&A) costs at $222.5 million annually. An incentive mechanism for variances will enable NGTL to capture savings from improved performance while providing for the flow-through of all other costs, including pipeline integrity expenses and emissions costs. On December 1, 2015, NGTL filed an application with the NEB for approval of the agreement.

- *Eastern Mainline Project and Energy East*: In October 2014, an application was filed for the Eastern Mainline Project, consisting of new gas facilities in southeastern Ontario required as a result of the proposed transfer of Canadian Mainline assets to crude oil service for the Energy East project. Application amendments were filed in December 2015 that reflect the agreement we announced in August 2015 with Eastern LDCs resolving their issues with Energy East and the Eastern Mainline Project. The agreement provides gas consumers in eastern Canada with sufficient natural gas transmission capacity to meet their needs and provides for reduced natural gas transmission costs. The Eastern Mainline Project capital cost is estimated to be $2.0 billion and is conditioned on the approval and construction of the Energy East pipeline.

- *Canadian Mainline Expansions*: In addition to the Eastern Mainline Project, new facilities totaling approximately $700 million over the 2016 to 2017 period in the Eastern Triangle portion of the Canadian Mainline are required to meet contractual commitments from shippers.

- *Tuxpan-Tula Pipeline*: In November 2015, we were awarded the contract to build, own and operate the US$500 million, 36-inch, 250 km (155 mile) Tuxpan-Tula pipeline under a 25-year contract with the Comision Federal de Electricidad (CFE). The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to each of those jurisdictions as well as the central region of Mexico. The pipeline will serve new power generating facilities as well as existing power plants that plan to switch from fuel oil to natural gas as their base fuel. Physical construction is expected to begin in 2016 with a planned in-service date in fourth quarter 2017.

- *Topolobampo and Mazatlan Pipelines*: The US$1 billion Topolobampo project and the US$400 million Mazatlan project are in their final construction stages. Both projects are supported by 25-year contracts with the CFE and are expected to be in-service in late 2016.

- *ANR Section 4 Rate Case***:** ANR Pipeline filed a Section 4 Rate Case with the Federal Energy Regulatory Commission (FERC) on January 29, 2016 that requests an increase to ANR's maximum transportation rates. Changes to ANR's traditional supply sources and markets, necessary operational changes, needed infrastructure updates, and evolving regulatory requirements are driving required investment in facility maintenance, reliability and system integrity as well as an increase in operating costs that have resulted in the current tariff rates not providing a reasonable return on our investment. We will also pursue a collaborative process to find a mutually beneficial outcome with our customers through settlement negotiations. ANR's last rate case filing was more than 20 years ago.

- *TC Offshore*: On December 18, 2015, we entered into an agreement to sell TC Offshore to a third party and expect the sale to close in early 2016. As a result, at December 31, 2015, the related assets and liabilities were classified as held for sale and recorded at their fair values less costs to sell, resulting in a loss on assets held for sale of $125 million ($86 million after-tax).

- *Sale of PNGTS to TC PipeLines, LP*: On January 1, 2016, we closed the sale of a 49.9 per cent interest of our total 61.7 per cent interest in PNGTS to TC PipeLines, LP for US$223 million including the assumption of US$35 million of proportional PNGTS debt.

- *Prince Rupert Gas Transmission*: In June 2015, Pacific Northwest LNG (PNW LNG) announced a positive Final Investment Decision (FID) for its proposed liquefaction and export facility, subject to two conditions. The first condition, approval by the Legislative Assembly of British Columbia of a Project Development Agreement between PNW LNG and the Province of B.C., was satisfied in July 2015. The second condition is a positive regulatory decision on PNW LNG's environmental assessment by the Government of Canada, which has not yet been received.

  Prince Rupert Gas Transmission (PRGT) has all of the primary regulatory permits required from the B.C. Oil and Gas Commission (BC OGC) and the B.C. Environmental Assessment Office for the project. We are continuing our engagement with Aboriginal groups and have now signed project agreements with ten First Nations along the pipeline route.

  We remain on target to begin construction following confirmation of a FID by PNW LNG. The in-service date for PRGT is estimated to be 2020 but will be aligned with PNW LNG's liquefaction facility timeline. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.

- *Coastal GasLink*: We continue to engage with stakeholders along the pipeline route and are progressing detailed engineering and construction planning work. We have received eight of ten pipeline and facilities permits from the BC OGC and anticipate receiving the remaining two permits in first quarter 2016. With these permits, Coastal GasLink will hold all of the required primary regulatory permits for the project. We are also continuing our engagement with Aboriginal groups along our pipeline route and have now signed long-term project agreements with eleven First Nations.

  Pending the receipt of regulatory approvals and a positive FID from the LNG Canada joint venture participants in 2016, we will begin construction. The pipeline in-service date will be scheduled to coincide with the operational requirements of the LNG Canada facility to be built in Kitimat, B.C. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.

- *Merrick Mainline***:** The proposed Merrick Mainline pipeline project that will transport natural gas sourced through the NGTL System to the inlet of the proposed Pacific Trail Pipeline terminating at the Kitimat LNG Terminal near Kitimat, B.C. has been delayed. In late 2015, the Kitimat LNG partners advised us that they are re-phasing the pace of Kitimat LNG facility development. Since the Merrick Mainline is dependent upon the construction of the downstream infrastructure, the in-service date of the Merrick Mainline will be no earlier than 2021.

Liquids Pipelines:

- *Keystone Pipeline System*: In fourth quarter 2015, we secured additional long term contracts bringing our total contract position to 545,000 Bbl/d.

- *Houston Lateral and Terminal*: On January 13, 2016, we entered into an agreement with Magellan Midstream Partners L.P. (Magellan) to connect our Houston Terminal to Magellan's Houston and Texas City, Texas delivery system. We will own 50 per cent of this US$50 million pipeline project which will enhance connections for our Keystone Pipeline System to the Houston market. The pipeline is expected to be operational during the first half of 2017, subject to the receipt of all necessary rights-of-way, permits and regulatory approvals.

- *CITGO Sour Lake Pipeline*: We have entered into an agreement with CITGO Petroleum (CITGO) to construct a US$65 million pipeline connection from the Keystone Pipeline System to provide access to CITGO’s Sour Lake, Texas terminal, which supplies their 425,000 Bbl/d Lake Charles, Louisiana refinery. The connection is targeted to be operational in fourth quarter 2016.

- *Keystone XL*: The decision on the Keystone XL permit application was delayed throughout 2015 by the U.S. Department of State and was ultimately denied in November 2015.

  At December 31, 2015, as a result of the denial of the Presidential permit, we evaluated our investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after-tax). The impairment charge was based on the excess of the carrying value over the fair value of $621 million, which includes a $93 million fair value for Keystone Hardisty Terminal. The Keystone Hardisty Terminal remains on hold with an estimated in-service date to be driven by market need.

  On January 6, 2016, we filed a Notice of Intent to initiate a claim under Chapter 11 of the North American Free Trade Agreement (NAFTA) in response to the U.S. Administration’s decision to deny a Presidential Permit for the Keystone XL Pipeline on the basis that the denial was arbitrary and unjustified. Through the NAFTA claim, we are seeking to recover more than US$15 billion in costs and damages that we have suffered as a result of the U.S. Administration’s breach of its NAFTA obligations.

  On the same day, we filed a lawsuit in the U.S. Federal Court in Houston, Texas, asserting that the U.S. President’s decision to deny construction of Keystone XL exceeded his power under the U.S. Constitution. The federal court lawsuit does not seek damages, but rather a declaration that the permit denial is without legal merit and that no further Presidential action is required before construction of the pipeline can proceed.

  We remain supportive of Keystone XL and continue to review our options, including filing a new application for a cross border permit.

- *Energy East Pipeline*: In December 2015, we filed an amendment to the existing Energy East Pipeline application with the NEB. The amendment adjusts the proposed route, scope and capital cost of the project reflecting refinement and scope change including the removal of a marine port in Québec. The project will continue to serve the three eastern Canadian refineries along the route in Montréal and Québec City, Québec and Saint John, New Brunswick. Changes to the project schedule and scope, as reflected in the amendment, have contributed to a new project capital cost of $15.7 billion, excluding the transfer of Canadian Mainline natural gas assets.

  Subject to regulatory approvals, the pipeline is anticipated to commence deliveries by the end of 2020. However, on January 27, 2016, the Canadian federal government announced interim measures for its review of the Energy East pipeline project. The government announced it will undertake additional consultations with aboriginal groups, help facilitate expanded public input into the NEB and assess Energy East's impact on upstream greenhouse gas emissions. The government will seek a six month extension to the NEB's legislative review and a three month extension to the legislative time limit for the government's decision which will extend the total review time to 27 months. We are reviewing these changes and will assess the impact to the project.

- *Northern Courier Pipeline:* Construction continues on the pipeline system to transport bitumen and diluent between the Fort Hills mine site and Suncor Energy’s terminal located north of Fort McMurray, Alberta. The project is fully underpinned by long term contracts with the Fort Hills partnership. We expect the pipeline system to be ready for service in 2017.

- *Grand Rapids Pipeline*: Grand Rapids Pipeline is a dual 36-inch/20-inch crude oil and diluent pipeline system connecting producing areas northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland, Alberta region. We have a joint partnership with Brion Energy to develop the Grand Rapids Pipeline with each owning 50 per cent of the pipeline project.

  Construction is progressing on phase one, which includes a 20-inch pipeline from northern Alberta to Edmonton, Alberta and a 36-inch pipeline between Edmonton and Fort Saskatchewan, Alberta. We anticipate phase one to begin crude oil transportation service in 2017. The construction of phase two, the larger 36-inch pipeline, is currently delayed and the in-service date will be subject to sufficient market demand.

Energy:

- *Bruce Power*: In December 2015, Bruce Power entered into an agreement with the Independent Electricity System Operator (IESO) to extend the operating life of the facility to the end of 2064. This new agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site.

  The amended agreement took effect on January 1, 2016 and allows Bruce Power to immediately invest in life extension activities for Units 3 through 8. Our share of investment in the Asset Management (AM) program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our share of investment in the Major Component Replacement (MCR) work, that is expected to occur between 2020 and 2033, is approximately $4 billion (2014 dollars). Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining MCR investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits. The agreement has been structured to account for changing cost inputs over time, including ongoing operating costs and additional capital investments. Beginning in 2016, Bruce Power receives a uniform price of $65.73 per MWh for all units. This price will be adjusted over the term of the agreement to incorporate incremental capital investment and cost changes.

  In connection with this opportunity, we exercised our option to acquire an additional 14.89 per cent ownership interest in Bruce B for $236 million from the Ontario Municipal Employees Retirement System (OMERS). Subsequent to this acquisition, Bruce A and Bruce B were merged to form a single partnership structure. In 2015 we recognized a charge of $36 million ($27 million after-tax), representing our proportionate share, on the retirement of Bruce Power debt in conjunction with this merger. TransCanada and OMERS each hold a 48.5 per cent interest in this newly merged partnership structure.

- *Ironwood*: On February 1, 2016, we acquired the 778 MW Ironwood natural gas fired, combined cycle power plant located in Lebanon, Pennsylvania from Talen Energy Corporation for US$657 million before post closing adjustments. The Ironwood power plant delivers energy into the PJM power market and will provide us with a solid platform from which to continue to grow our wholesale, commercial and industrial customer base in this market area.

- *Napanee Project*: Construction activities continue on the 900 MW Napanee natural gas-fired power plant in eastern Ontario. We expect to invest approximately $1.0 billion in the facility during construction and commercial operations are expected to begin in late 2017 or early 2018. Production from the facility is fully contracted with the IESO.

- *Turbine Equipment Impairment Charge*: In the fourth quarter of 2015 we recorded an impairment loss of $59 million for turbine equipment previously purchased for a new power development project that did not proceed.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.565 per share for the quarter ending March 31, 2016 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.26 per common share on an annualized basis and represents a nine per cent increase over the previous amount. This is the sixteenth consecutive year the Board of Directors has raised the dividend.

- *Common Share Repurchase*: On November 19, 2015, the Company announced that the Toronto Stock Exchange (TSX) had approved a normal course issuer bid which allows for the repurchase of up to 21.3 million common shares between November 23, 2015 and November 22, 2016 at prevailing market prices plus brokerage fees, or such other prices as may be permitted by the TSX. As at February 10, 2016, the Company had repurchased 7.1 million common shares for $307 million under this program.

- *Corporate Restructuring and Business Transformation:* In mid-2015, we commenced a business restructuring and transformation initiative. While there is no change to our corporate strategy, we undertook this initiative to maximize the effectiveness and efficiency of our existing operations and reduce overall costs. In the fourth quarter, we recorded a charge of $60 million after-tax comprised of $28 million related to the 2015 program and a provision of $32 million for planned severance costs related to 2016 and expected losses under lease commitments. For the year ended December 31, 2015, the charge totaled $74 million after-tax.

- *Financing Activity*: In October 2015, we issued $400 million of medium-term notes maturing on November 15, 2041 bearing interest at 4.55 per cent and in November 2015, we issued US$1.0 billion of two-year fixed rate notes maturing on November 9, 2017 bearing interest at 1.625 per cent. In January 2016, we issued a further US$1.25 billion in the U.S. debt capital markets comprised of US$850 million of 10-year notes bearing interest at 4.875 per cent and US$400 million of 3-year notes bearing interest at 3.125 per cent.

Teleconference and Webcast:

We will hold a teleconference and webcast on Thursday, February 11, 2016 to discuss our fourth quarter 2015 financial results. Russ Girling, TransCanada President and Chief Executive Officer, and Don Marchand, Executive Vice-President, Corporate Development and Chief Financial Officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 1 p.m. (MT) / 3 p.m. (ET).

Analysts, members of the media and other interested parties are invited to participate by calling 866.223.7781 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 18, 2016. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 9573850.

The audited annual Consolidated Financial Statements and Management's Discussion and Analysis (MD&A) are available under TransCanada's profile on SEDAR at www.sedar.com, with the U.S. Securities and Exchange Commission on EDGAR at www.sec.gov/info/edgar.shtml and on the TransCanada website at www.transcanada.com.

With more than 65 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 67,000 kilometres (42,000 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with 368 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 13,100 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest liquids delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. Visit TransCanada.com and our blog to learn more, or connect with us on social media and 3BL Media.

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Fourth quarter 2015 financial highlights

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2015**	**2014**	**2015**	**2014**
Income				
Revenues	**2,851**	2,616	**11,300**	10,185
Net (loss)/income attributable to common shares	**(2,458)**	458	**(1,240)**	1,743
per common share - basic and diluted	**($3.47)**	$0.65	**($1.75)**	$2.46
Comparable EBITDA[1]	**1,527**	1,521	**5,908**	5,521
Comparable earnings[1]	**453**	511	**1,755**	1,715
per common share[1]	**$0.64**	$0.72	**$2.48**	$2.42
Operating cash flow				
Funds generated from operations[1]	**1,159**	1,178	**4,513**	4,268
(Increase)/decrease in operating working capital	**(20)**	12	**(398)**	(189)
Net cash provided by operations	**1,139**	1,190	**4,115**	4,079
Comparable distributable cash flow[1]	**778**	786	**3,546**	3,406
per common share[1]	**$1.10**	$1.11	**$5.00**	$4.81
Investing activities				
Capital spending - capital expenditures	**1,170**	1,108	**3,918**	3,489
Capital spending - projects in development	**46**	344	**511**	848
Contributions to equity investments	**190**	61	**493**	256
Acquisitions, net of cash acquired	**236**	60	**236**	241
Proceeds from sale of assets, net of transaction costs	**—**	9	**—**	196
Dividends declared				
Per common share	**$0.52**	$0.48	**$2.08**	$1.92
Basic common shares outstanding (millions)				
Average for the period	**708**	709	**709**	708
End of period	**703**	709	**703**	709

1 Comparable EBITDA, comparable earnings, comparable earnings per common share, funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. See the non-GAAP measures section for more information on the non-GAAP measures we use and the Reconciliation of non-GAAP measures section for reconciliations to their GAAP equivalents.

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 common share purchases under our normal course issuer bid
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- 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 and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- 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, tax 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 2014 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
- distributable cash flow
- distributable cash flow per common share
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable distributable cash flow
- comparable distributable cash flow per common share
- comparable income from equity investments
- comparable interest expense
- comparable interest income and other
- comparable income tax expense
- comparable net income attributable to non-controlling interests.

These measures do not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other entities. Please see the Reconciliation of non-GAAP measures section in this news release for a reconciliation of the GAAP measures to the non-GAAP measures.

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting 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 a useful measure of our performance and an effective tool for evaluating trends in each segment as it is equivalent to our segmented earnings. 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 a useful 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 and is used to provide a consistent measure of the cash generating performance of our assets. See the Financial condition section for a reconciliation to net cash provided by operations.

Distributable cash flow

Distributable cash flow is defined as funds generated from operations plus distributions in excess of equity earnings less preferred share dividends, distributions to non-controlling interests and maintenance capital expenditures. Maintenance capital expenditures represent costs which are necessary to preserve the operating ability of our assets and investments. We believe it is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. See the Reconciliation of non-GAAP measures section for a reconciliation to net cash provided by operations.

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	segmented earnings
comparable distributable cash flow	distributable cash flow
comparable distributable cash flow per common share	distributable cash flow per common share
comparable income from equity investments	income from equity investments
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income tax expense	income tax expense
comparable net income attributable to non-controlling interests	net income attributable to non-controlling interests

Our decision not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:
- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments and changes to enacted rates
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of assets and investments.

In calculating comparable earnings and other comparable measures we exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally 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 unrealized changes in fair value do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

Consolidated results - fourth quarter 2015

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2015**	**2014**	**2015**	**2014**
Natural Gas Pipelines	**572**	621	**2,220**	2,187
Liquids Pipelines	**(3,413)**	230	**(2,630)**	843
Energy	**82**	219	**812**	1,051
Corporate	**(161)**	(43)	**(301)**	(150)
Total segmented (losses)/earnings	**(2,920)**	1,027	**101**	3,931
Interest expense	**(380)**	(323)	**(1,370)**	(1,198)
Interest income and other	**80**	28	**163**	91
(Loss)/income before income taxes	**(3,220)**	732	**(1,106)**	2,824
Income tax recovery/(expense)	**646**	(206)	**(34)**	(831)
Net (loss)/income	**(2,574)**	526	**(1,140)**	1,993
Net loss/(income) attributable to non-controlling interests	**139**	(43)	**(6)**	(153)
Net (loss)/income attributable to controlling interests	**(2,435)**	483	**(1,146)**	1,840
Preferred share dividends	**(23)**	(25)	**(94)**	(97)
Net (loss)/income attributable to common shares	**(2,458)**	458	**(1,240)**	1,743
Net (loss)/income per common share - basic and diluted	**($3.47)**	$0.65	**($1.75)**	$2.46

Net income attributable to common shares decreased by $2,916 million to a net loss of $2,458 million for the three months ended December 31, 2015 compared to the same period in 2014. The 2015 results included:

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore expected to close in early 2016
- a net charge of $60 million after tax for our business restructuring and transformation initiative comprised of $28 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value on turbine equipment held for future use in our Energy business
- a charge of $27 million after-tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

The 2014 results included:

- an $8 million after-tax gain on sale of our 30 per cent interest in Gas Pacifico/INNERGY.

Net income in both periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above-noted items, to arrive at comparable earnings.

Comparable earnings decreased by $58 million for the three months ended December 31, 2015 compared to the same period in 2014 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	2015	2014	2015	2014
Net income attributable to common shares	**(2,458)**	458	**(1,240)**	1,743
Specific items (net of tax):				
Keystone XL impairment charge	**2,891**	—	**2,891**	—
TC Offshore loss on sale	**86**	—	**86**	—
Restructuring costs	**60**	—	**74**	—
Turbine equipment impairment charge	**43**	—	**43**	—
Alberta corporate income tax rate increase	**—**	—	**34**	—
Bruce Power merger - debt retirement charge	**27**	—	**27**	—
Non-controlling interests - (TC PipeLines, LP - Great Lakes impairment)	**(199)**	—	**(199)**	—
Cancarb gain on sale	**—**	—	**—**	(99)
Niska contract termination	**—**	—	**—**	32
Gas Pacifico/INNERGY gain on sale	**—**	(8)	**—**	(8)
Risk management activities[1]	**3**	61	**39**	47
Comparable earnings	**453**	511	**1,755**	1,715
Net (loss)/income per common share	**($3.47)**	$0.65	**($1.75)**	$2.46
Specific items (net of tax):				
Keystone XL impairment charge	**4.08**	—	**4.08**	—
TC Offshore loss on sale	**0.12**	—	**0.12**	—
Restructuring costs	**0.08**	—	**0.10**	—
Turbine equipment impairment charge	**0.06**	—	**0.06**	—
Alberta corporate income tax rate increase	**—**	—	**0.05**	—
Bruce Power merger - debt retirement charge	**0.04**	—	**0.04**	—
Non-controlling interests - (TC PipeLines, LP - Great Lakes impairment)	**(0.28)**	—	**(0.28)**	—
Cancarb gain on sale	**—**	—	**—**	(0.14)
Niska contract termination	**—**	—	**—**	0.04
Gas Pacifico/INNERGY gain on sale	**—**	(0.01)	**—**	(0.01)
Risk management activities[1]	**0.01**	0.08	**0.06**	0.07
Comparable earnings per common share	**$0.64**	$0.72	**$2.48**	$2.42

1

Risk management activities	three months ended December 31		year ended December 31	
(unaudited - millions of $)	2015	2014	2015	2014
Canadian Power	**(1)**	(11)	**(8)**	(11)
U.S. Power	**(8)**	(85)	**(30)**	(55)
Natural Gas Storage	**(1)**	9	**1**	13
Foreign exchange	**4**	(12)	**(21)**	(21)
Income tax attributable to risk management activities	**3**	38	**19**	27
Total losses from risk management activities	**(3)**	(61)	**(39)**	(47)

Comparable earnings decreased by $58 million for the three months ended December 31, 2015 compared to the same period in 2014. This was primarily the net effect of:

- lower Canadian Mainline incentive earnings
- lower earnings from Canadian Power due to lower realized power prices and PPA volumes from Western Power, lower earnings from Bruce Power due to higher planned outage days and higher operating expenses at Bruce A, partially offset by fewer planned outage days and lower lease expense at Bruce B and lower earnings on sale of unused natural gas transportation from Eastern Power

- higher earnings from Liquids Pipelines due to higher contracted volumes
- higher interest expense due to long-term debt issuances and the ceasing of capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential permit.

The stronger U.S. dollar in 2015 compared to 2014 positively impacted the translated results in our U.S. businesses, however, this impact was partially offset by a corresponding increase in interest expense on U.S. dollar-denominated debt as well as realized losses on foreign exchange hedges used to manage our exposure.

CAPITAL PROGRAM

We are developing quality projects under our long-term capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cash flow.

Our capital program consists of $13 billion of near-term projects and $45 billion of commercially secured medium and longer-term projects. Amounts presented exclude the impact of foreign exchange, capitalized interest and AFUDC.

All project costs are subject to adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at December 31, 2015 (unaudited - billions of $)	Estimated Project Cost	Carrying Value
Summary		
Near-term projects	13.4	3.9
Medium to Longer-term projects	45.2	2.1
Total Capital Program	**58.6**	**6.0**
Foreign exchange impact on Capital Program[1]	4.5	0.8

1 Reflects foreign exchange rate of $1.38 at December 31, 2015.

Near-term projects

at December 31, 2015 (unaudited - billions of $)	Segment	Expected in-service date	Estimated project cost	Carrying value
Ironwood Acquisition	Energy	2016	US 0.7	—
Houston Lateral and Terminal	Liquids Pipelines	2016	US 0.6	US 0.5
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.9
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.3
Grand Rapids Phase 1[1]	Liquids Pipelines	2017	0.9	0.5
Northern Courier	Liquids Pipelines	2017	1.0	0.6
Tuxpan-Tula	Natural Gas Pipelines	2017	US 0.5	—
Canadian Mainline - Other	Natural Gas Pipelines	2016-2017	0.7	0.1
NGTL System - North Montney	Natural Gas Pipelines	2017	1.7	0.3
- 2016/17 Facilities	Natural Gas Pipelines	2016-2018	2.7	0.3
- 2018 Facilities	Natural Gas Pipelines	2018	0.6	—
- Other	Natural Gas Pipelines	2016-2017	0.4	0.1
Napanee	Energy	2017 or 2018	1.0	0.3
Bruce Power - life extension[1]	Energy	2016-2020	1.2	—
Total Near-term projects			**13.4**	**3.9**

1 Our proportionate share.

Medium to Longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are 2019 and beyond, and costs provided in the schedule below reflect the most recent costs for each project as filed with the various regulatory authorities or otherwise disclosed. These projects have all been commercially secured but are subject to approvals that include sponsor FID and/or complex regulatory processes.

at December 31, 2015 (unaudited - billions of $)	Segment	Estimated project cost	Carrying value
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Upland	Liquids Pipelines	US 0.6	—
Grand Rapids Phase 2[1]	Liquids Pipelines	0.7	—
Bruce Power - life extension[1]	Energy	5.3	—
Keystone projects			
Keystone XL[2]	Liquids Pipelines	US 8.0	US 0.4
Keystone Hardisty Terminal[2]	Liquids Pipelines	0.3	0.1
Energy East projects			
Energy East[3]	Liquids Pipelines	15.7	0.7
Eastern Mainline Project	Natural Gas Pipelines	2.0	0.1
BC west coast LNG-related projects			
Coastal GasLink	Natural Gas Pipelines	4.8	0.3
Prince Rupert Gas Transmission	Natural Gas Pipelines	5.0	0.4
NGTL System - Merrick	Natural Gas Pipelines	1.9	—
Total Medium to Longer-term projects		**45.2**	**2.1**

1 Our proportionate share.
2 Carrying value reflects amount remaining after impairment charge.
3 Excludes transfer of Canadian Mainline natural gas assets.

Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See the non-GAAP measures section for more information on the non-GAAP measures we use as well as the reconciliation of non-GAAP measures section for reconciliations to their GAAP equivalents.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable EBITDA	**984**	884	**3,477**	3,241
Depreciation and amortization	**(287)**	(272)	**(1,132)**	(1,063)
Comparable EBIT	**697**	612	**2,345**	2,178
Specific items:				
TC Offshore loss on sale	**(125)**	—	**(125)**	—
Gas Pacifico/INNERGY gain on sale	**—**	9	**—**	9
Segmented earnings	**572**	621	**2,220**	2,187

Natural Gas Pipelines segmented earnings decreased by $49 million for the three months ended December 31, 2015 compared to the same period in 2014 and included a $125 million pre-tax loss provision recorded as a result of a December 2015 agreement to sell TC Offshore, which is expected to close in early 2016. Segmented earnings in 2014 included a $9 million pre-tax gain related to the sale of Gas Pacifico/INNERGY in November 2014. These amounts have been excluded from our calculation of comparable EBIT. Comparable EBIT and comparable EBITDA are discussed below.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Canadian Pipelines				
Canadian Mainline	**354**	396	**1,230**	1,334
NGTL System	**259**	219	**934**	856
Foothills	**26**	26	**107**	106
Other Canadian pipelines[1]	**6**	5	**27**	22
Canadian Pipelines - comparable EBITDA	**645**	646	**2,298**	2,318
Depreciation and amortization	**(213)**	(208)	**(845)**	(821)
Canadian Pipelines - comparable EBIT	**432**	438	**1,453**	1,497
U.S. and International Pipelines (US$)				
ANR	**55**	47	**232**	189
TC PipeLines, LP[1,2]	**30**	23	**106**	88
Great Lakes[3]	**28**	13	**63**	49
Other U.S. pipelines (Bison[4], Iroquois[1], GTN[5], Portland[6])	**18**	32	**84**	132
Mexico (Guadalajara, Tamazunchale)	**43**	43	**181**	160
International and other[1,7]	**2**	(5)	**4**	(10)
Non-controlling interests[8]	**84**	65	**292**	241
U.S. and International Pipelines - comparable EBITDA	**260**	218	**962**	849
Depreciation and amortization	**(55)**	(57)	**(224)**	(219)
U.S. and International Pipelines - comparable EBIT	**205**	161	**738**	630
Foreign exchange impact	**68**	24	**206**	68
U.S. and International Pipelines - comparable EBIT (Cdn$)	**273**	185	**944**	698
Business Development comparable EBITDA and EBIT	**(8)**	(11)	**(52)**	(17)
Natural Gas Pipelines - comparable EBIT	**697**	612	**2,345**	2,178

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments. In November 2014, we sold our interest in Gas Pacifico/INNERGY.
2 Beginning in August 2014, TC PipeLines, LP began its at-the-market equity issuance program which, when utilized, decreases our ownership interest in TC PipeLines, LP. On October 1, 2014, we sold our remaining 30 per cent direct interest in Bison to TC PipeLines, LP. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of GTN, Bison and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of			
	December 31, 2015	**April 1, 2015**	**October 1, 2014**	**January 1, 2014**
TC PipeLines, LP	28.0	28.3	28.3	28.9
Effective ownership through TC PipeLines, LP:				
Bison	28.0	28.3	28.3	20.2
GTN	28.0	28.3	19.8	20.2
Great Lakes	13.0	13.1	13.1	13.4

3 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.
4 Effective October 1, 2014, we have no direct ownership in Bison. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013.
5 Effective April 1, 2015, we have no direct ownership in GTN. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013.
6 Represents our 61.7 per cent ownership interest.
7 Includes our share of the equity income from TransGas and Gas Pacifico/INNERGY as well as general and administration costs relating to our U.S. and International Pipelines. In November 2014, we sold our interest in Gas Pacifico/INNERGY.
8 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

CANADIAN PIPELINES

Net income and comparable EBITDA for our rate-regulated Canadian pipelines are generally affected by the approved ROE, investment base, level of deemed common equity, incentive earnings or losses and, if material, carrying charges on revenue and cost variances that are recovered in revenue on a flow-through basis. Changes in depreciation, financial charges and taxes also impact comparable EBITDA and comparable EBIT but do not have a significant impact in net income as they are almost entirely recovered in revenue on a flow-through basis.

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Canadian Mainline	**52**	115	**213**	300
NGTL System	**69**	59	**269**	241
Foothills	**4**	4	**15**	17

Net income for the Canadian Mainline decreased by $63 million for the three months ended December 31, 2015 compared to the same period in 2014 primarily due to a lower average investment base in 2015 and a lower ROE of 10.1 per cent in 2015 compared to 11.5 per cent in 2014. Incentive earnings of $59 million for 2014 were recorded in the fourth quarter 2014 contributing to the higher net income in that period.

Net income for the NGTL System increased by $10 million for the three months ended December 31, 2015 compared to the same period in 2014 mainly due to a higher average investment base and OM&A incentive losses realized in 2014.

U.S. AND INTERNATIONAL PIPELINES

Earnings for our U.S. natural gas pipelines operations are 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 contracting and pricing of its storage capacity and incidental commodity sales.

Comparable EBITDA for U.S. and International Pipelines increased by US$42 million for the three months ended December 31, 2015 compared to the same period in 2014. This increase was the net effect of higher ANR Southeast Mainline transportation revenue, partially offset by increased spending on ANR pipeline integrity work.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $15 million for the three months ended December 31, 2015 compared to the same period in 2014 mainly because of a higher investment base on the NGTL System, depreciation for the completed Tamazunchale Extension, and the effect of a stronger U.S. dollar.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

year ended December 31	**Canadian Mainline[1]**		**NGTL System[2]**		**ANR[3]**	
(unaudited)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Average investment base (millions of $)	**4,784**	5,690	**6,698**	6,236	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**1,595**	1,645	**3,884**	3,891	**1,600**	1,588
Average per day	**4.4**	4.5	**10.6**	10.7	**4.4**	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 year ended December 31, 2015 were 1,122 Bcf (2014 – 1,228 Bcf). Average per day was 3.1 Bcf (2014 – 3.4 Bcf).
2 Field receipt volumes for the NGTL System for the year ended December 31, 2015 were 4,029 Bcf (2014 – 3,888 Bcf). Average per day was 11.0 Bcf (2014 – 10.7 Bcf).
3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See the non-GAAP measures section for more information on the non-GAAP measures we use as well as the reconciliation of non-GAAP measures section for reconciliations to their GAAP equivalents.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable EBITDA	**342**	288	**1,322**	1,059
Depreciation and amortization	**(69)**	(58)	**(266)**	(216)
Comparable EBIT	**273**	230	**1,056**	843
Specific item:				
Keystone XL impairment charge	**(3,686)**	—	**(3,686)**	—
Segmented (losses)/earnings	**(3,413)**	230	**(2,630)**	843

Liquids Pipelines segmented earnings decreased by $3,643 million to a segmented loss of $3,413 million for the three months ended December 31, 2015 compared to the same period in 2014. The segmented loss in 2015 included a $3,686 million pre-tax impairment charge related to Keystone XL and related projects in connection with the denial of the U.S. Presidential permit. This amount has been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Keystone Pipeline System	**348**	294	**1,345**	1,073
Liquids Pipelines Business Development	**(6)**	(6)	**(23)**	(14)
Liquids Pipelines - comparable EBITDA	**342**	288	**1,322**	1,059
Depreciation and amortization	**(69)**	(58)	**(266)**	(216)
Liquids Pipelines - comparable EBIT	**273**	230	**1,056**	843

Comparable EBIT denominated as follows:				
Canadian dollars	**61**	58	**236**	215
U.S. dollars	**160**	153	**640**	570
Foreign exchange impact	**52**	19	**180**	58
	273	230	**1,056**	843

Comparable EBITDA for the Keystone Pipeline System is generated primarily by providing pipeline capacity to shippers 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 $54 million for the three months ended December 31, 2015 compared to the same period in 2014 and was primarily due to:

- higher contracted volumes
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $11 million for the three months ended December 31, 2015 compared to the same period in 2014 primarily due to the effect of a stronger U.S. dollar.

Energy

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See the non-GAAP measures section for more information on the non-GAAP measures we use as well as the reconciliation of non-GAAP measures section for reconciliations to their GAAP equivalents.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable EBITDA	**275**	385	**1,280**	1,348
Depreciation and amortization	**(88)**	(79)	**(336)**	(309)
Comparable EBIT	**187**	306	**944**	1,039
Specific items (pre-tax):				
Turbine equipment impairment charge	**(59)**	—	**(59)**	—
Bruce Power merger - debt retirement charge	**(36)**	—	**(36)**	—
Cancarb gain on sale	**—**	—	**—**	108
Niska contract termination	**—**	—	**—**	(43)
Risk management activities	**(10)**	(87)	**(37)**	(53)
Segmented earnings	**82**	219	**812**	1,051

Energy segmented earnings decreased by $137 million for the three months ended December 31, 2015 compared to the same period in 2014 and included the following specific items:

- a $59 million pre-tax charge relating to an impairment in value on turbine equipment previously purchased for a new power development project that did not proceed. Various other projects have recently been evaluated for possible use of this equipment and those evaluations support the impairment of the carrying value. The evaluation included a comparison to similar assets available for sale on the market
- a pre-tax charge of $36 million related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- unrealized losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities	three months ended December 31		year ended December 31	
(unaudited - millions of $, pre-tax)	**2015**	**2014**	**2015**	**2014**
Canadian Power	**(1)**	(11)	**(8)**	(11)
U.S. Power	**(8)**	(85)	**(30)**	(55)
Natural Gas Storage	**(1)**	9	**1**	13
Total losses from risk management activities	**(10)**	(87)	**(37)**	(53)

The period-over-period variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our positions for these particular derivatives over a certain period of time; however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them representative of our underlying operations.

The specific items noted above have been excluded in our calculation of comparable EBIT. The remainder of the Energy segmented earnings are equivalent to comparable EBIT, which, along with EBITDA, are discussed below.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	2015	2014	2015	2014
Canadian Power				
Western Power	**(1)**	59	**72**	252
Eastern Power	**85**	111	**394**	350
Bruce Power	**83**	115	**285**	314
Canadian Power - comparable EBITDA[1]	**167**	285	**751**	916
Depreciation and amortization	**(49)**	(46)	**(190)**	(179)
Canadian Power - comparable EBIT[1]	**118**	239	**561**	737
U.S. Power (US$)				
U.S. Power - comparable EBITDA	**80**	85	**418**	376
Depreciation and amortization	**(27)**	(27)	**(105)**	(107)
U.S. Power - comparable EBIT	**53**	58	**313**	269
Foreign exchange impact	**19**	8	**87**	27
U.S. Power - comparable EBIT (Cdn$)	**72**	66	**400**	296
Natural Gas Storage and other - comparable EBITDA	**7**	12	**15**	44
Depreciation and amortization	**(3)**	(3)	**(12)**	(12)
Natural Gas Storage and other - comparable EBIT	**4**	9	**3**	32
Business Development comparable EBITDA and EBIT	**(7)**	(8)	**(20)**	(26)
Energy - comparable EBIT[1]	**187**	306	**944**	1,039

1 Includes our share of equity income from our investments in ASTC Power Partnership and Portlands Energy, and our share of comparable income from equity investments from Bruce Power.

Comparable EBITDA for Energy decreased by $110 million for the three months ended December 31, 2015 compared to the same period in 2014 due to the net effect of:

- lower earnings from Western Power as a result of lower realized power prices and PPA volumes
- lower earnings from Bruce Power due to lower volumes resulting from higher planned outage days and higher operating expenses at Bruce A, partially offset by higher volumes resulting from fewer planned outage days and lower lease expense at Bruce B
- lower earnings from Eastern Power primarily due to lower earnings on the sale of unused natural gas transportation
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

CANADIAN POWER

Western and Eastern Power

(unaudited - millions of $)	three months ended December 31 2015	three months ended December 31 2014	year ended December 31 2015	year ended December 31 2014
Revenue[1]				
Western Power	**122**	189	**534**	736
Eastern Power	**97**	106	**455**	428
Other[2]	**13**	28	**62**	85
	232	323	**1,051**	1,249
(Loss)/income from equity investments[3]	**(5)**	3	**8**	45
Commodity purchases resold	**(87)**	(108)	**(353)**	(404)
Plant operating costs and other	**(57)**	(59)	**(248)**	(299)
Exclude risk management activities[1]	**1**	11	**8**	11
Comparable EBITDA	**84**	170	**466**	602
Depreciation and amortization	**(49)**	(46)	**(190)**	(179)
Comparable EBIT	**35**	124	**276**	423
Breakdown of comparable EBITDA				
Western Power	**(1)**	59	**72**	252
Eastern Power	**85**	111	**394**	350
Comparable EBITDA	**84**	170	**466**	602

1 The realized and unrealized gains and losses from financial derivatives used to manage Canadian Power's assets are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives included in revenue are excluded to arrive at Comparable EBITDA.

2 Includes revenues from the sale of unused natural gas transportation, sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black up to April 15, 2014 when it was sold.

3 Includes our share of equity (loss)/income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy. Equity (loss)/income does not include any earnings related to our risk management activities.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

	three months ended December 31		year ended December 31	
(unaudited)	2015	2014	2015	2014
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**643**	660	**2,519**	2,517
Eastern Power	**766**	644	**3,911**	3,080
Purchased				
Sundance A & B and Sheerness PPAs[1]	**2,809**	3,283	**10,617**	11,472
Other purchases	**59**	7	**154**	16
	4,277	4,594	**17,201**	17,085
Sales				
Contracted				
Western Power	**2,080**	3,004	**7,707**	10,484
Eastern Power	**766**	644	**3,911**	3,080
Spot				
Western Power	**1,431**	946	**5,583**	3,521
	4,277	4,594	**17,201**	17,085
Plant availability[2]				
Western Power[3]	**97%**	97%	**97%**	96%
Eastern Power[4]	**96%**	93%	**97%**	91%

1 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Does not include facilities that provide power to us under PPAs.
4 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Comparable EBITDA for Western Power decreased by $60 million for the three months ended December 31, 2015 compared to the same period in 2014. The decrease was due to lower realized power prices and lower PPA volumes.

Average spot market power prices in Alberta decreased by 32 per cent from $31/MWh to $21/MWh for the three months ended December 31, 2015 compared to the same period in 2014. The addition of new natural gas-fired power plants in 2015 have contributed to a well supplied market and few higher priced hours were observed. 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.

The $8 million decrease in equity earnings for the three months ended December 31, 2015 compared to the same period in 2014 is primarily due to the impact of lower Alberta spot market prices on earnings from the ASTC Power Partnership which holds our 50 per cent ownership interest in the Sundance B PPA. Equity earnings do not include the impact of related contracting activities.

Fifty-nine per cent of Western Power sales volumes were sold under contract in fourth quarter 2015 compared to 76 per cent in fourth quarter 2014.

Eastern Power

Comparable EBITDA for Eastern Power decreased by $26 million for the three months ended December 31, 2015 compared to the same period in 2014 due to lower earnings on the sale of unused natural gas transportation and lower contractual earnings at Bécancour.

BRUCE POWER

Results reflect our proportionate share. Beginning in 2016, results from Bruce Power will be reported on a combined basis to reflect the merged entity. Comparable income from equity investments is a non-GAAP measure. See the non-GAAP measures section for more information on the non-GAAP measures we use.

	three months ended December 31		year ended December 31	
(unaudited - millions of $, unless noted otherwise)	**2015**	**2014**	**2015**	**2014**
Comparable income from equity investments[1]				
Bruce A	**42**	100	**205**	209
Bruce B	**41**	15	**80**	105
	83	115	**285**	314
Comprised of:				
Revenues	**356**	361	**1,301**	1,256
Operating expenses	**(193)**	(162)	**(691)**	(623)
Depreciation and other	**(80)**	(84)	**(325)**	(319)
Comparable income from equity investments[1]	**83**	115	**285**	314
Bruce Power merger - debt retirement charge	**(36)**	—	**(36)**	—
Income from equity investments[1]	**47**	115	**249**	314
Bruce Power - Other information				
Plant availability[2]				
Bruce A	**87%**	96%	**87%**	82%
Bruce B	**97%**	84%	**87%**	90%
Combined Bruce Power	**92%**	91%	**87%**	86%
Planned outage days				
Bruce A	**38**	—	**164**	118
Bruce B	**2**	53	**163**	127
Unplanned outage days				
Bruce A	**9**	13	**28**	123
Bruce B	**6**	4	**17**	4
Sales volumes (GWh)[1]				
Bruce A	**2,809**	3,299	**11,148**	10,526
Bruce B	**2,579**	1,915	**8,210**	8,197
	5,388	5,214	**19,358**	18,723
Realized sales price per MWh[3]				
Bruce A	**$67**	$72	**$71**	$72
Bruce B	**$57**	$58	**$55**	$56
Combined Bruce Power	**$61**	$65	**$63**	$63

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B up to December 3, 2015 when we increased our ownership percentage in Bruce B, and Bruce A and B were merged. Sales volumes include deemed generation.
2 The percentage of time in a year the plant was available to generate power, regardless of whether it was running.
3 Calculation based on actual and deemed generation. Bruce B realized sales price per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Comparable income from equity investments from Bruce A decreased by $58 million for the three months ended December 31, 2015 compared to the same period in 2014 mainly due to lower volumes resulting from higher planned outage days and higher operating expenses.

Comparable income from equity investments from Bruce B increased by $26 million for the three months ended December 31, 2015 compared to the same period in 2014 mainly due to higher volumes resulting from lower planned outage days and lower lease expense based on the terms of the lease agreement with Ontario Power Generation.

On December 3, 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 2064. This new agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site.

The amended agreement, which took economic effect on January 1, 2016, allows Bruce Power to immediately invest in life extension activities for Units 3 through 8 to support the long-term refurbishment program. This early investment in the Asset Management program will result in near-term life extension, allowing later investment in the Major Component Replacement work that is expected to begin in 2020.

As part of the life extension and refurbishment agreement, Bruce Power began receiving a uniform price of $65.73 per MWh for all units in January 2016. Over time, the price will be subject to adjustments for the return of and on capital invested under the Asset Management and Major Component Replacement capital programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term.

Our estimated share of investment related to the Asset Management program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our estimated share of investment in the Major Component Replacement work for Units 3 through 8 over the 2020 to 2033 timeframe is approximately a further $4 billion (2014 dollars).

Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining Major Component Replacement investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits. The agreement has been structured to account for changing cost inputs over time, including ongoing operating costs and larger capital investments.

On December 3, 2015, we exercised our option to acquire an additional 14.89 per cent ownership interest in Bruce B for $236 million from the Ontario Municipal Employees Retirement System. On December 4, 2015, Bruce B and Bruce A were merged to form a single partnership structure through Bruce Power LP with us now owning a 48.5 per cent ownership interest. Prior to the acquisition of additional Bruce B ownership and the merger, we owned 48.9 per cent of Bruce A and 31.6 per cent of Bruce B.

Prior to the amended agreement with the IESO, all of the output from Bruce A Units 1 to 4 was sold at a fixed price/MWh which was adjusted annually on April 1 for inflation and other provisions under the contract. Bruce A also recovered fuel costs from the IESO.

Bruce A fixed price	**per MWh**
April 1, 2015 - December 31, 2015	$73.42
April 1, 2014 - March 31, 2015	$71.70
April 1, 2013 - March 31, 2014	$70.99

Prior to the amended agreement with the IESO, all output from Bruce B Units 5 to 8 was subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price	**per MWh**
April 1, 2015 - December 31, 2015	$54.13
April 1, 2014 - March 31, 2015	$52.86
April 1, 2013 - March 31, 2014	$52.34

Amounts received under the Bruce B Units 5 - 8 floor price mechanism within a calendar year were subject to repayment if the average spot price in a month exceeded the floor price. The average spot power price in each month of 2015 was less than the floor price and therefore no amounts received under the floor price mechanism in 2015 are subject to repayment.

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 contract also provides for payment if the IESO reduces Bruce Power's generation to balance the supply of and demand for electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered "deemed generation", for which Bruce Power is paid the contract price.

U.S. POWER

	three months ended December 31		year ended December 31	
(unaudited - millions of US$)	2015	2014	2015	2014
Revenue				
Power[1]	**423**	301	**1,975**	1,794
Capacity	**63**	84	**317**	362
	486	385	**2,292**	2,156
Commodity purchases resold	**(315)**	(270)	**(1,474)**	(1,297)
Plant operating costs and other[2]	**(96)**	(103)	**(422)**	(529)
Exclude risk management activities[1]	**5**	73	**22**	46
Comparable EBITDA	**80**	85	**418**	376
Depreciation and amortization	**(27)**	(27)	**(105)**	(107)
Comparable EBIT	**53**	58	**313**	269

1 The realized and unrealized gains and losses from financial derivatives used to manage U.S. Power's assets are presented on a net basis in Power revenues. The unrealized gains and losses from financial derivatives included in revenue are excluded to arrive at Comparable EBITDA.
2 Includes the cost of fuel consumed in generation.

Sales volumes and plant availability

	three months ended December 31		year ended December 31	
(unaudited)	2015	2014	2015	2014
Physical sales volumes (GWh)				
Supply				
Generation	**2,093**	1,580	**7,849**	7,742
Purchased	**5,137**	3,866	**20,937**	13,798
	7,230	5,446	**28,786**	21,540
Plant availability[1,2]	**79%**	60%	**78%**	82%

1 The percentage of time the plant was available to generate power, regardless of whether it was running.
2 Plant availability was higher in the three months ended December 31, 2015 than the same period in 2014 due to an unplanned outage at the Ravenswood facility from September 2014 - May 2015.

U.S. Power - other information

	three months ended December 31		year ended December 31	
(unaudited)	2015	2014	2015	2014
Average Spot Power Prices (US$ per MWh)				
New England[1]	30	41	42	65
New York[2]	24	36	39	61
Average New York[2] Spot Capacity Prices (US$ per KW-M)	9.22	11.92	11.44	13.96

1 New England ISO all hours Mass Hub price.
2 Zone J market in New York City where the Ravenswood plant operates.

Comparable EBITDA for U.S. Power decreased US$5 million for the three months ended December 31, 2015 compared to the same period in 2014 primarily due to the net effect of:

- lower capacity revenue at Ravenswood due to lower realized capacity prices in New York and the impact of lower availability at the facility
- lower realized power prices at our New England facilities
- higher generation at our Ravenswood facility
- higher sales to wholesale, commercial and industrial customers in both the PJM and New England markets.

Average New York Zone J spot capacity prices were approximately 23 per cent lower for the three months ended December 31, 2015 compared to the same period in 2014. The decrease in spot prices and the impact of hedging activities resulted in lower realized capacity prices in New York in 2015. This was primarily due to increased available operational supply in New York City's Zone J market.

Capacity revenues were also negatively impacted by an outage from September 2014 to May 2015 at Ravenswood. The calculation used by the NYISO to determine the capacity volume for which a generator is compensated utilizes a rolling average forced outage rate. As a result of this methodology, outages impact capacity volumes and associated revenues on a lagged basis. Accordingly, capacity revenues for the three months ended December 31, 2015 were negatively impacted compared to the same period in 2014. The outage continues to be included in the rolling average forced outage rate.

Wholesale electricity prices in New York and New England were lower for the three months ended December 31, 2015 compared to the same period in 2014. In New England, spot power prices for the three months ended December 31, 2015 were 27 per cent lower compared to the same period in 2014. In New York City, spot power prices were 33 per cent lower for the three months ended December 31, 2015 compared to the same period in 2014. Both markets have experienced lower natural gas commodity prices throughout 2015 compared to 2014.

Physical sales volumes and purchased volumes sold to wholesale, commercial and industrial customers were higher for the three months ended December 31, 2015 than the same period in 2014 as we have expanded our customer base in both the PJM and New England markets.

As at December 31, 2015, approximately 6,600 GWh or 70 per cent of U.S. Power's planned generation is contracted for 2016, and 3,000 GWh or 33 per cent for 2017. 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 for Natural Gas Storage and Other decreased by $5 million for the three months ended December 31, 2015 compared to the same period in 2014 mainly due to decreased proprietary revenue as a result of lower realized natural gas storage price spreads.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). See the non-GAAP measures section for more information on the non-GAAP measures we use as well as the reconciliation of non-GAAP measures section for reconciliations to their GAAP equivalent.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable EBITDA	**(74)**	(36)	**(171)**	(127)
Depreciation and amortization	**(8)**	(7)	**(31)**	(23)
Comparable EBIT	**(82)**	(43)	**(202)**	(150)
Specific items:				
Restructuring costs	**(79)**	—	**(99)**	—
Segmented losses	**(161)**	(43)	**(301)**	(150)

Corporate segmented losses for the three months ended December 31, 2015 increased by $118 million compared to the same period in 2014 and included a charge of $79 million before tax for restructuring charges comprised of $36 million related to 2015 severance costs and a provision of $43 million for 2016 planned severance costs and expected future losses under lease commitments. This amount has been excluded from our calculation of comparable EBIT and EBITDA.

Other income statement items

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures for other income statement items. See the non-GAAP measures section for more information on the non-GAAP measures we use.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian-dollar denominated	**(113)**	(108)	**(437)**	(443)
U.S. dollar-denominated	**(234)**	(216)	**(911)**	(854)
Foreign exchange	**(78)**	(30)	**(255)**	(90)
	(425)	(354)	**(1,603)**	(1,387)
Other interest and amortization expense	**(12)**	(29)	**(47)**	(70)
Capitalized interest	**57**	60	**280**	259
Comparable interest expense	**(380)**	(323)	**(1,370)**	(1,198)
Specific items[1]	**—**	—	**—**	—
Interest expense	**(380)**	(323)	**(1,370)**	(1,198)

1 There were no specific items in any of these periods.

Comparable interest expense increased by $57 million for the three months ended December 31, 2015 compared to the same period in 2014 due to the net effect of:

- higher interest expense reflecting debt issues of:
  - US$1.0 billion in November 2015
  - $400 million in October 2015
  - $750 million in July 2015
  - US$750 million in May 2015
  - US$750 million in March 2015
  - US$350 million in March 2015 by TC PipeLines, LP
  - US$750 million in January 2015
- partially offset by U.S. dollar-denominated debt maturities

- a stronger U.S. dollar and its effect on the foreign exchange impact on interest expense related to U.S. dollar-denominated debt
- lower carrying charges to shippers in 2015 on positive net revenue variance for Canadian Mainline
- higher capitalized interest primarily due to LNG projects and the Napanee power generating facility, partially offset by the ceasing of capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential permit.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable interest income and other	**76**	40	**184**	112
Specific items (pre-tax):				
Risk management activities	**4**	(12)	**(21)**	(21)
Interest income and other	**80**	28	**163**	91

Comparable interest income and other increased by $36 million for the three months ended December 31, 2015 compared to the same period in 2014 due to the net effect of:

- increased AFUDC related to our rate-regulated projects, primarily the Energy East Pipeline and our Mexico pipelines
- higher realized losses in 2015 compared to 2014 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on the U.S. dollar-denominated income
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable income tax expense	**(235)**	(243)	**(903)**	(859)
Specific items:				
Keystone XL impairment charge	**795**	—	**795**	—
TC Offshore loss on sale	**39**	—	**39**	—
Restructuring costs	**19**	—	**25**	—
Turbine equipment impairment charge	**16**	—	**16**	—
Alberta corporate income tax rate increase	**—**	—	**(34)**	—
Bruce Power merger - debt retirement charge	**9**	—	**9**	—
Cancarb gain on sale	**—**	—	**—**	(9)
Niska contract termination	**—**	—	**—**	11
Gas Pacifico/ INNERGY gain on sale	**—**	(1)	**—**	(1)
Risk management activities	**3**	38	**19**	27
Income tax recovery/(expense)	**646**	(206)	**(34)**	(831)

Comparable income tax expense decreased by $8 million for the three months ended December 31, 2015 compared to the same period in 2014 and was mainly the result of lower pre-tax earnings and changes in the proportion of income earned between Canadian and foreign jurisdictions.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable net income attributable to non-controlling interests	**(60)**	(43)	**(205)**	(153)
Specific item:				
TC PipeLines, LP - Great Lakes impairment	**199**	—	**199**	—
Net loss/(income) attributable to non-controlling interests	**139**	(43)	**(6)**	(153)

Net income attributable to non-controlling interests decreased by $182 million for the three months ended December 31, 2015 compared to the same period in 2014 due to an impairment charge recorded by TC PipeLines, LP related to their equity investment goodwill in Great Lakes. At December 31, 2015, TC PipeLines, LP recorded an impairment of US$199 million. On consolidation, we recorded the non-controlling interest's 72 per cent of this TC PipeLines, LP impairment charge which was US$143 million or $199 million (in Canadian dollars). The TC PipeLines, LP impairment charge is not recognized at the TransCanada consolidation level as a result of our lower carrying value of Great Lakes. This $199 million positive impact to net income attributable to non-controlling interests is excluded from comparable net income attributable to non-controlling interests.

Comparable net income attributable to non-controlling interests increased by $17 million for the three months ended December 31, 2015 compared to the same period in 2014 primarily due to higher earnings resulting from the sale of our remaining 30 per cent direct interests in GTN in April 2015 to TC PipeLines, LP along with the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP.

Preferred share dividends were $23 million for the three months and $94 million for the year ended December 31, 2015 (2014 - $25 million and $97 million, respectively).

Reconciliation of non-GAAP measures

(unaudited - millions of $, except per share amounts)	three months ended December 31 2015	three months ended December 31 2014	year ended December 31 2015	year ended December 31 2014
EBITDA	**(2,468)**	1,443	**1,866**	5,542
Specific items:				
Keystone XL impairment charge	**3,686**	—	**3,686**	—
TC Offshore loss on sale	**125**	—	**125**	—
Restructuring costs	**79**	—	**99**	—
Turbine equipment impairment charge	**59**	—	**59**	—
Bruce Power merger - debt retirement charge	**36**	—	**36**	—
Cancarb gain on sale	**—**	—	**—**	(108)
Niska contract termination	**—**	—	**—**	43
Gas Pacifico/ INNERGY gain on sale	**—**	(9)	**—**	(9)
Risk management activities[1]	**10**	87	**37**	53
Comparable EBITDA	**1,527**	1,521	**5,908**	5,521
Depreciation and amortization	**452**	416	**1,765**	1,611
Comparable EBIT	**1,075**	1,105	**4,143**	3,910
Other income statement items				
Comparable interest expense	**(380)**	(323)	**(1,370)**	(1,198)
Comparable interest income and other	**76**	40	**184**	112
Comparable income tax expense	**(235)**	(243)	**(903)**	(859)
Comparable net income attributable to non-controlling interests	**(60)**	(43)	**(205)**	(153)
Preferred share dividends	**(23)**	(25)	**(94)**	(97)
Comparable earnings	**453**	511	**1,755**	1,715
Specific items (net of tax):				
Keystone XL impairment charge	**(2,891)**	—	**(2,891)**	—
TC Offshore loss on sale	**(86)**	—	**(86)**	—
Restructuring costs	**(60)**	—	**(74)**	—
Turbine equipment impairment charge	**(43)**	—	**(43)**	—
Alberta corporate income tax rate increase	**—**	—	**(34)**	—
Bruce Power merger - debt retirement charge	**(27)**	—	**(27)**	—
Non-controlling interests (TC PipeLines, LP - Great Lakes impairment)	**199**	—	**199**	—
Cancarb gain on sale	**—**	—	**—**	99
Niska contract termination	**—**	—	**—**	(32)
Gas Pacifico/ INNERGY gain on sale	**—**	8	**—**	8
Risk management activities[1]	**(3)**	(61)	**(39)**	(47)
Net (loss)/income attributable to common shares	**(2,458)**	458	**(1,240)**	1,743
Comparable interest income and other	**76**	40	**184**	112
Specific items:				
Risk management activities[1]	**4**	(12)	**(21)**	(21)
Interest income and other	**80**	28	**163**	91

(unaudited - millions of $, except per share amounts)	three months ended December 31				year ended December 31			
		2015		**2014**		**2015**		**2014**
Comparable income tax expense		**(235)**		(243)		**(903)**		(859)
Specific items:								
Keystone XL impairment charge		**795**		—		**795**		—
TC Offshore loss on sale		**39**		—		**39**		—
Restructuring costs		**19**		—		**25**		—
Turbine equipment impairment charge		**16**		—		**16**		—
Bruce Power merger - debt retirement charge		**9**		—		**9**		—
Alberta corporate income tax rate increase		**—**		—		**(34)**		—
Cancarb gain on sale		**—**		—		**—**		(9)
Niska contract termination		**—**		—		**—**		11
Gas Pacifico/ INNERGY gain on sale		**—**		(1)		**—**		(1)
Risk management activities[1]		**3**		38		**19**		27
Income tax recovery/(expense)		**646**		(206)		**(34)**		(831)
Comparable earnings per common share	**$**	**0.64**	$	0.72	**$**	**2.48**	$	2.42
Specific items (net of tax):								
Keystone XL impairment charge		**(4.08)**		—		**(4.08)**		—
TC Offshore loss on sale		**(0.12)**		—		**(0.12)**		—
Restructuring costs		**(0.08)**		—		**(0.10)**		—
Turbine equipment impairment charge		**(0.06)**		—		**(0.06)**		—
Alberta corporate income tax rate increase		**—**		—		**(0.05)**		—
Bruce Power merger - debt retirement charge		**(0.04)**		—		**(0.04)**		—
Non-controlling interests (TC PipeLines, LP - Great Lakes impairment)		**0.28**		—		**0.28**		—
Cancarb gain on sale		**—**		—		**—**		0.14
Niska contract termination		**—**		—		**—**		(0.04)
Gas Pacifico/ INNERGY gain on sale		**—**		0.01		**—**		0.01
Risk management activities[1]		**(0.01)**		(0.08)		**(0.06)**		(0.07)
Net (loss)/income per common share	**$**	**(3.47)**	$	0.65	**$**	**(1.75)**	$	2.46

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Risk management activities	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Canadian Power	**(1)**	(11)	**(8)**	(11)
U.S. Power	**(8)**	(85)	**(30)**	(55)
Natural Gas Storage	**(1)**	9	**1**	13
Foreign exchange	**4**	(12)	**(21)**	(21)
Income tax attributable to risk management activities	**3**	38	**19**	27
Total losses from risk management activities	**(3)**	(61)	**(39)**	(47)

Comparable EBITDA and EBIT by business segment

three months ended December 31, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**859**	**(3,344)**	**170**	**(153)**	**(2,468)**
Specific items:					
Keystone XL impairment charge	**—**	**3,686**	**—**	**—**	**3,686**
TC Offshore loss on sale	**125**	**—**	**—**	**—**	**125**
Restructuring costs	**—**	**—**	**—**	**79**	**79**
Turbine equipment impairment charge	**—**	**—**	**59**	**—**	**59**
Bruce Power merger - debt retirement charge	**—**	**—**	**36**	**—**	**36**
Risk management activities	**—**	**—**	**10**	**—**	**10**
Comparable EBITDA	**984**	**342**	**275**	**(74)**	**1,527**
Depreciation and amortization	**(287)**	**(69)**	**(88)**	**(8)**	**(452)**
Comparable EBIT	**697**	**273**	**187**	**(82)**	**1,075**

three months ended December 31, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	893	288	298	(36)	1,443
Specific items:					
Gas Pacifico/INNERGY gain on sale	(9)	—	—	—	(9)
Risk management activities	—	—	87	—	87
Comparable EBITDA	884	288	385	(36)	1,521
Depreciation and amortization	(272)	(58)	(79)	(7)	(416)
Comparable EBIT	612	230	306	(43)	1,105

year ended December 31, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**3,352**	**(2,364)**	**1,148**	**(270)**	**1,866**
Specific items:					
Keystone XL impairment charge	**—**	**3,686**	**—**	**—**	**3,686**
TC Offshore loss on sale	**125**	**—**	**—**	**—**	**125**
Restructuring costs	**—**	**—**	**—**	**99**	**99**
Turbine equipment impairment charge	**—**	**—**	**59**	**—**	**59**
Bruce Power merger - debt retirement charge	**—**	—	**36**	—	**36**
Risk management activities	**—**	**—**	**37**	**—**	**37**
Comparable EBITDA	**3,477**	**1,322**	**1,280**	**(171)**	**5,908**
Depreciation and amortization	**(1,132)**	**(266)**	**(336)**	**(31)**	**(1,765)**
Comparable EBIT	**2,345**	**1,056**	**944**	**(202)**	**4,143**

year ended December 31, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	3,250	1,059	1,360	(127)	5,542
Specific items:					
Cancarb gain on sale	—	—	(108)	—	(108)
Niska contract termination	—	—	43	—	43
Gas Pacifico/INNERGY gain on sale	(9)	—	—	—	(9)
Risk management activities	—	—	53	—	53
Comparable EBITDA	3,241	1,059	1,348	(127)	5,521
Depreciation and amortization	(1,063)	(216)	(309)	(23)	(1,611)
Comparable EBIT	2,178	843	1,039	(150)	3,910

Comparable Distributable Cash Flow

(unaudited - millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2015	**2014**	**2015**	**2014**
Net cash provided by operations	**1,139**	1,190	**4,115**	4,079
Increase/(decrease) in operating working capital	**20**	(12)	**398**	189
Funds generated from operations	**1,159**	1,178	**4,513**	4,268
Distributions in excess of equity earnings	**5**	10	**226**	159
Preferred share dividends paid	**(23)**	(25)	**(92)**	(94)
Distributions paid to non-controlling interests	**(56)**	(44)	**(224)**	(178)
Maintenance capital expenditures including equity investments	**(353)**	(333)	**(937)**	(781)
Distributable cash flow	**732**	786	**3,486**	3,374
Specific items impacting distributable cash flow (net of tax):				
Restructuring costs	**46**	—	**60**	—
Niska contract termination	**—**	—	**—**	32
Comparable distributable cash flow	**778**	786	**3,546**	3,406
Comparable distributable cash flow per common share	**$1.10**	$1.11	**$5.00**	$4.81

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended December 31		year ended December 31	
	2015	**2014**	**2015**	**2014**
Revenues				
Natural Gas Pipelines	**1,487**	1,399	**5,383**	4,913
Liquids Pipelines	**469**	435	**1,879**	1,547
Energy	**895**	782	**4,038**	3,725
	2,851	2,616	**11,300**	10,185
Income from Equity Investments	**90**	160	**440**	522
Operating and Other Expenses				
Plant operating costs and other	**906**	810	**3,250**	2,973
Commodity purchases resold	**506**	414	**2,237**	1,836
Property taxes	**127**	118	**517**	473
Depreciation and amortization	**452**	416	**1,765**	1,611
Asset impairment charges	**3,745**	—	**3,745**	—
	5,736	1,758	**11,514**	6,893
(Loss)/Gain on Assets Held for Sale/Sold	**(125)**	9	**(125)**	117
Financial Charges				
Interest expense	**380**	323	**1,370**	1,198
Interest income and other	**(80)**	(28)	**(163)**	(91)
	300	295	**1,207**	1,107
(Loss)/Income before Income Taxes	**(3,220)**	732	**(1,106)**	2,824
Income Tax (Recovery)/Expense				
Current	**12**	41	**136**	145
Deferred	**(658)**	165	**(102)**	686
	(646)	206	**34**	831
Net (Loss)/Income	**(2,574)**	526	**(1,140)**	1,993
Net (loss)/income attributable to non-controlling interests	**(139)**	43	**6**	153
Net (Loss)/Income Attributable to Controlling Interests	**(2,435)**	483	**(1,146)**	1,840
Preferred share dividends	**23**	25	**94**	97
Net (Loss)/Income Attributable to Common Shares	**(2,458)**	458	**(1,240)**	1,743
Net (Loss)/Income per Common Share				
Basic and diluted	**($3.47)**	$0.65	**($1.75)**	$2.46
Dividends Declared per Common Share	**$0.52**	$0.48	**$2.08**	$1.92
Weighted Average Number of Common Shares (millions)				
Basic	**708**	709	**709**	708
Diluted	**708**	710	**709**	710

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended December 31 2015	three months ended December 31 2014	year ended December 31 2015	year ended December 31 2014
Cash Generated from Operations				
Net (loss)/income	**(2,574)**	526	**(1,140)**	1,993
Depreciation and amortization	**452**	416	**1,765**	1,611
Asset impairment charges	**3,745**	—	**3,745**	—
Deferred income taxes	**(658)**	165	**(102)**	686
Income from equity investments	**(90)**	(160)	**(440)**	(522)
Distributed earnings received from equity investments	**179**	164	**576**	579
Employee post-retirement benefits expense, net of funding	**3**	9	**44**	37
Loss/(gain) on assets held for sale/sold	**125**	(9)	**125**	(117)
Equity allowance for funds used during construction	**(50)**	(36)	**(165)**	(95)
Unrealized losses on financial instruments	**6**	99	**58**	74
Other	**21**	4	**47**	22
(Increase)/decrease in operating working capital	**(20)**	12	**(398)**	(189)
Net cash provided by operations	**1,139**	1,190	**4,115**	4,079
Investing Activities				
Capital expenditures	**(1,170)**	(1,108)	**(3,918)**	(3,489)
Capital projects in development	**(46)**	(344)	**(511)**	(848)
Contributions to equity investments	**(190)**	(61)	**(493)**	(256)
Acquisitions, net of cash acquired	**(236)**	(60)	**(236)**	(241)
Proceeds from sale of assets, net of transaction costs	**—**	9	**—**	196
Distributions in excess of equity earnings	**5**	10	**226**	159
Deferred amounts and other	**82**	(106)	**322**	335
Net cash used in investing activities	**(1,555)**	(1,660)	**(4,610)**	(4,144)
Financing Activities				
Notes payable (repaid)/issued, net	**(554)**	689	**(1,382)**	544
Long-term debt issued, net of issue costs	**1,722**	23	**5,045**	1,403
Long-term debt repaid	**(39)**	(49)	**(2,105)**	(1,069)
Junior subordinated notes issued, net of issue costs	**—**	—	**917**	—
Dividends on common shares	**(368)**	(340)	**(1,446)**	(1,345)
Dividends on preferred shares	**(23)**	(25)	**(92)**	(94)
Distributions paid to non-controlling interests	**(56)**	(44)	**(224)**	(178)
Common shares issued	**15**	4	**27**	47
Common shares repurchased	**(294)**	—	**(294)**	—
Preferred shares issued, net of issue costs	**—**	—	**243**	440
Partnership units of subsidiary issued, net of issue costs	**24**	—	**55**	79
Preferred shares of subsidiary redeemed	**—**	—	**—**	(200)
Net cash provided by/(used in) financing activities	**427**	258	**744**	(373)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**84**	3	**112**	—
Increase/(Decrease) in Cash and Cash Equivalents	**95**	(209)	**361**	(438)
Cash and Cash Equivalents				
Beginning of period	**755**	698	**489**	927
Cash and Cash Equivalents				
End of period	**850**	489	**850**	489

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		December 31, 2015	December 31, 2014
ASSETS			
Current Assets			
Cash and cash equivalents		**850**	489
Accounts receivable		**1,388**	1,313
Inventories		**323**	292
Other		**1,353**	1,019
		3,914	3,113
Plant, Property and Equipment	net of accumulated depreciation of $22,299 and $19,864, respectively	**44,817**	41,774
Equity Investments		**6,214**	5,598
Regulatory Assets		**1,184**	1,297
Goodwill		**4,812**	4,034
Intangible and Other Assets		**3,191**	2,646
Restricted Investments		**351**	63
		64,483	58,525
LIABILITIES			
Current Liabilities			
Notes payable		**1,218**	2,467
Accounts payable and other		**3,021**	2,892
Accrued interest		**520**	424
Current portion of long-term debt		**2,547**	1,797
		7,306	7,580
Regulatory Liabilities		**1,159**	263
Other Long-Term Liabilities		**1,260**	1,052
Deferred Income Tax Liabilities		**5,144**	4,857
Long-Term Debt		**29,037**	22,960
Junior Subordinated Notes		**2,422**	1,160
		46,328	37,872
EQUITY			
Common shares, no par value		**12,102**	12,202
Issued and outstanding:	December 31, 2015 - 703 million shares		
	December 31, 2014 - 709 million shares		
Preferred shares		**2,499**	2,255
Additional paid-in capital		**7**	370
Retained earnings		**2,769**	5,478
Accumulated other comprehensive loss		**(939)**	(1,235)
Controlling Interests		**16,438**	19,070
Non-controlling interests		**1,717**	1,583
		18,155	20,653
		64,483	58,525

Segmented information

three months ended December 31	Natural Gas Pipelines		Liquids Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Revenues	**1,487**	1,399	**469**	435	**895**	782	**—**	—	**2,851**	2,616
Income from equity investments	**45**	39	**—**	—	**45**	121	**—**	—	**90**	160
Plant operating costs and other	**(463)**	(471)	**(109)**	(133)	**(181)**	(170)	**(153)**	(36)	**(906)**	(810)
Commodity purchases resold	**—**	—	**—**	—	**(506)**	(414)	**—**	—	**(506)**	(414)
Property taxes	**(85)**	(83)	**(18)**	(14)	**(24)**	(21)	**—**	—	**(127)**	(118)
Depreciation and amortization	**(287)**	(272)	**(69)**	(58)	**(88)**	(79)	**(8)**	(7)	**(452)**	(416)
Asset impairment charges	**—**	—	**(3,686)**	—	**(59)**	—	**—**	—	**(3,745)**	—
(Loss)/gain on assets held for sale/sold	**(125)**	9	**—**	—	**—**	—	**—**	—	**(125)**	9
Segmented earnings/(losses)	**572**	621	**(3,413)**	230	**82**	219	**(161)**	(43)	**(2,920)**	1,027
Interest expense									**(380)**	(323)
Interest income and other									**80**	28
(Loss)/Income before income taxes									**(3,220)**	732
Income tax recovery/(expense)									**646**	(206)
Net (loss)/income									**(2,574)**	526
Net loss/(income) attributable to non-controlling interests									**139**	(43)
Net (loss)/income attributable to controlling interests									**(2,435)**	483
Preferred share dividends									**(23)**	(25)
Net (loss)/income attributable to common shares									**(2,458)**	458

year ended December 31	Natural Gas Pipelines		Liquids Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Revenues	**5,383**	4,913	**1,879**	1,547	**4,038**	3,725	**—**	—	**11,300**	10,185
Income from equity investments	**179**	163	**—**	—	**261**	359	**—**	—	**440**	522
Plant operating costs and other	**(1,736)**	(1,501)	**(478)**	(426)	**(766)**	(919)	**(270)**	(127)	**(3,250)**	(2,973)
Commodity purchases resold	**—**	—	**—**	—	**(2,237)**	(1,836)	**—**	—	**(2,237)**	(1,836)
Property taxes	**(349)**	(334)	**(79)**	(62)	**(89)**	(77)	**—**	—	**(517)**	(473)
Depreciation and amortization	**(1,132)**	(1,063)	**(266)**	(216)	**(336)**	(309)	**(31)**	(23)	**(1,765)**	(1,611)
Asset impairment charges	**—**	—	**(3,686)**	—	**(59)**	—	**—**	—	**(3,745)**	—
(Loss)/gain on assets held for sale/sold	**(125)**	9	**—**	—	**—**	108	**—**	—	**(125)**	117
Segmented earnings/(loss)	**2,220**	2,187	**(2,630)**	843	**812**	1,051	**(301)**	(150)	**101**	3,931
Interest expense									**(1,370)**	(1,198)
Interest income and other									**163**	91
(Loss)/Income before income taxes									**(1,106)**	2,824
Income tax expense									**(34)**	(831)
Net (loss)/income									**(1,140)**	1,993
Net income attributable to non-controlling interests									**(6)**	(153)
Net (loss)/income attributable to controlling interests									**(1,146)**	1,840
Preferred share dividends									**(94)**	(97)
Net (loss)/income attributable to common shares									**(1,240)**	1,743

TOTAL ASSETS

(unaudited - millions of Canadian $)	December 31, 2015	December 31, 2014
Natural Gas Pipelines	**31,072**	27,103
Liquids Pipelines	**16,046**	16,116
Energy	**15,558**	14,197
Corporate	**1,807**	1,109
	64,483	58,525