
TransCanada Reports Solid Third Quarter Results From Its Three Core Businesses Announces \$4.7 Billion of New Capital Projects

CALGARY, Alberta – **November 4, 2014** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for third quarter 2014 of \$457 million or \$0.64 per share compared to \$481 million or \$0.68 per share for the same period in 2013. Comparable earnings for third quarter 2014 were \$450 million or \$0.63 per share compared to \$447 million or \$0.63 per share for the same period last year. TransCanada's Board of Directors also declared a quarterly dividend of \$0.48 per common share for the quarter ending December 31, 2014, equivalent to \$1.92 per common share on an annualized basis.

"Our three core businesses generated solid earnings and cash flow during the quarter," said Russ Girling, TransCanada's president and chief executive officer. "Contributions from new assets like the Keystone Gulf Coast Extension and the Tamazunchale Extension in Mexico, along with strong results from Bruce Power, highlight the benefits of a diversified and growing portfolio of pipeline and power assets. We are also pleased to have announced an additional \$4.7 billion of new capital projects highlighting the organic growth opportunities that are tied to our unparalleled asset footprint."

Since the beginning of 2014, we have captured \$6.6 billion of capital projects related to our Canadian regulated natural gas pipeline assets. This includes \$2.7 billion of new investment associated with the NGTL System, \$2 billion of expansions and facility modifications to the Canadian Mainline in Ontario and the previously announced \$1.9 billion Merrick Mainline Pipeline Project. With these additions, our capital program now totals \$46 billion of commercially secured projects, essentially all of which are backed by long-term contracts or cost of service business models. This growth portfolio includes \$24 billion of liquids pipelines, \$20 billion of natural gas pipelines and \$2 billion of power generation facilities. We continue to advance this unprecedented slate of growth initiatives, with many currently proceeding through their respective regulatory processes. Over the remainder of the decade, subject to required approvals, this blue-chip portfolio of contracted energy infrastructure is expected to generate significant sustainable growth in earnings, cash flow and dividends.

On October 1, 2014, we closed the sale of our remaining 30 per cent interest in Bison Pipeline LLC (Bison) to our master limited partnership, TC PipeLines, LP (the Partnership) for cash proceeds of US\$215 million. This transaction underscores our commitment to drop down all of our remaining U.S. natural gas pipeline assets to the Partnership on a more sizable and more frequent basis over the coming quarters and years. This will provide us with significant cash proceeds and is an important element of funding our unprecedented growth portfolio, while enhancing the size and diversity of the Partnership's asset base, positioning it with visible, high quality future growth.

Looking forward, our current asset base and financial strength positions us well to generate significant long-term shareholder value through execution of our industry-leading capital program and our commitment to continuously evaluate our approach to capital allocation.

Highlights

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

- Third quarter financial results
 - Net income attributable to common shares of \$457 million or \$0.64 per share
 - Comparable earnings of \$450 million or \$0.63 per share
 - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of \$1.4 billion
 - Funds generated from operations of \$1.1 billion
- Declared a quarterly dividend of \$0.48 per common share for the quarter ending December 31, 2014
- Filed regulatory applications with the National Energy Board (NEB) for the \$12 billion Energy East Project and the \$1.5 billion Eastern Mainline Project on October 30, 2014
- Announced an additional \$2.7 billion of expansion projects on the NGTL System

- Executed new short-haul contracts on the Canadian Mainline that require new, or modifications to existing, facilities totaling \$500 million
- Received regulatory approval for the \$800 million Northern Courier Pipeline Project in July
- Closed the \$181 million purchase of three additional solar facilities in Ontario in late September
- Received regulatory approval for the \$1.5 billion Grand Rapids Pipeline Project in October
- Advanced our master limited partnership strategy with the drop down of the remaining 30 per cent interest in Bison for US\$215 million

Net income attributable to common shares decreased by \$24 million to \$457 million or \$0.64 per share for the three months ended September 30, 2014 compared to the same period in 2013 and, in both years, included unrealized gains and losses from changes in certain risk management activities.

Comparable earnings for third quarter 2014 were \$450 million or \$0.63 per share compared to \$447 million or \$0.63 per share for the same period in 2013. Higher earnings from Keystone, Mexican Pipelines and U.S. Power were offset by lower contributions from Western Power, U.S. Pipelines and Gas Storage.

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

Liquids Pipelines:

- *Energy East Pipeline:* On October 30, 2014, we filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline project and terminal facilities with the NEB. The 1.1 million barrel per day (bbl/d) project received approximately 900,000 bbl/d of firm, long-term contracts during a binding open season to transport crude oil from Western Canada to eastern refineries and export terminals. The project is estimated to cost approximately \$12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries to Québec and New Brunswick by the end of 2018.
- *Keystone XL:* On January 31, 2014, the Department of State (DOS) released its Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is “unlikely to significantly impact the rate of extraction in the oil sands” and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period that was to last up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment. On April 18, 2014, the DOS announced that the National Interest Determination period has been extended indefinitely to allow them to consider the potential impact of the case discussed below on the Nebraska portion of the pipeline route.

In February 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL project. Nebraska’s Attorney General filed an appeal which was heard by the Nebraska State Supreme Court on September 5, 2014. It is not known when the Nebraska State Supreme Court will release its decision.

On September 15, 2014, we filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (PUC). This certification confirms that the conditions under which Keystone XL’s original June 2010 PUC construction permit was granted persist. It is unknown when the South Dakota PUC will release its decision.

Due to continued delays in acquiring U.S. regulatory approvals and increasing regulatory conditions, the estimated capital costs for the Keystone XL project have increased from US\$5.4 billion as provided in the DOS regulatory filing, to approximately US\$8.0 billion. As of September 30, 2014, we have invested US\$2.4 billion in the project.

- *Grand Rapids Pipeline Project:* On October 9, 2014, the Alberta Energy Regulator (AER) issued a permit approving the majority of our application to construct and operate the Grand Rapids Pipeline Project. The \$3 billion Grand Rapids Pipeline Project is a 50/50 joint venture between us and Brion Energy Corporation (Brion), formerly Phoenix Energy Holdings Limited, to develop an oil and diluent pipeline system connecting the producing area northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland region. Brion has also entered into a long-term transportation service contract in support of the project. Construction is expected to begin in fourth quarter 2014 and the system is expected to become operational in stages, with initial crude oil transported by mid-2016. Once completed in 2017, the full system will have an ultimate capacity to move up to 900,000 bbl/d of crude oil and 330,000 bbl/d of diluent.
- *Northern Courier Pipeline Project:* On July 18, 2014, the AER issued a permit approving our application to construct and operate the Northern Courier Pipeline Project. Construction commenced in third quarter 2014 and the pipeline system is expected to begin service in 2017. The \$800 million pipeline will transport bitumen and diluent between the Fort Hills oil sands mining project and Suncor Energy's East Tank Farm located north of Fort McMurray, Alberta, and is fully contracted under a long-term agreement.

Natural Gas Pipelines:

- *NGTL System Expansions:* We continue to experience significant growth on the NGTL System as a result of increasing natural gas supply in northwestern Alberta and northeastern British Columbia (B.C.) from unconventional gas plays and substantive growth in intra-basin delivery markets driven primarily by oil sands development and demand for gas-fired electric power generation. This demand for NGTL System services is expected to result in a total of approximately 4.0 billion cubic feet per day (Bcf/d) of incremental firm service contracts. Approximately 3.1 Bcf/d of this volume relates to firm receipt service and 0.9 Bcf/d relates to firm delivery service. Significant new facilities consisting of approximately 540 kilometres (336 miles) of pipeline, seven compressor stations, and 40 meter stations will be required in 2016 and 2017 (2016/17 Facilities). The estimated total capital cost for the 2016/17 Facilities is approximately \$2.7 billion.

Approximately \$285 million of capital projects have been placed in service in the nine months ended September 30, 2014. Including the new 2016/17 Facilities capital requirements, we have approximately \$6.7 billion of projects in development that have, or will be filed with the NEB for approval. This includes the North Montney Mainline and the Merrick Mainline Pipeline projects, along with other new supply and demand facilities.

- *NGTL System Revenue Requirement Settlement:* We have reached a revenue requirement settlement with our shippers for 2015. The terms of the one year settlement include no changes to the return on equity of 10.1 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed operating, maintenance and administrative expense amount. The settlement was filed with the NEB on October 31, 2014.
- *Canadian Mainline - LDC Settlement:* In March 2014, the NEB responded to the LDC Settlement application we filed in December 2013. The NEB did not approve the application as a settlement but allowed us the option to continue with the application as a contested tolls application, amend the application or terminate the processing of the application. We amended the application with additional information. In May 2014, the NEB released a Hearing Order that set out a hearing process and schedule for the 2015 - 2030 Mainline Tolls application that incorporates the LDC Settlement. The hearing concluded September 25, 2014. We anticipate a decision from the NEB before the end of 2014.
- *Canadian Mainline Expansions:* On October 30, 2014 we filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario. The new facilities are a result of the proposed transfer of a portion of Canadian Mainline capacity to crude oil from natural gas service as part of our Energy East Pipeline and an open season that closed in January 2014. The \$1.5 billion Eastern Mainline Project will add 0.6 Bcf/d of new capacity and will ensure appropriate levels of capacity are available to meet the

requirements of existing shippers as well as new firm service commitments in the Eastern Triangle segment of the Canadian Mainline. Subject to regulatory approvals, the project is expected to be in service by second quarter 2017.

In addition to the Eastern Mainline Project, we have executed new short-haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new, or modifications to existing facilities with a total capital cost estimate of \$475 million. Approximately \$255 million of these projects have an expected in-service date of November 1, 2015 including the Kings North Connection, Parkway West Connection and the Hamilton Area Project. The Vaughan Loop and compressor station piping modifications, with a capital cost of approximately \$220 million, have an expected in-service date of November 1, 2016. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in Eastern Canada.

- *Bison Pipeline Sale:* On October 1, 2014, the remaining 30 per cent interest in Bison was sold to our master limited partnership, TC PipeLines, LP for cash proceeds of US\$215 million. This transaction advances our previously stated commitment to sell the remainder of TransCanada's U.S. natural gas pipeline assets to the Partnership to help fund our capital program and enhance the size and diversity of the Partnership's asset base, positioning it with visible, high quality future growth. The U.S. natural gas pipeline assets that remain directly-held by TransCanada are expected to generate approximately US\$480 million of EBITDA in 2016 and beyond.

At September 30, 2014, we hold a 28.3 per cent interest in TC PipeLines, LP.

- *Tamazunchale Pipeline Extension Project:* Construction of the US\$600 million extension is now expected to be completed in fourth quarter 2014 with delays attributed to archeological findings along the pipeline route. Under the terms of the Transportation Service Agreement, these delays are recognized as a force majeure with provisions allowing for collection of revenue as per the original service commencement date of March 9, 2014.
- *Coastal GasLink Pipeline Project:* On October 24, 2014, the B.C. Environmental Assessment Office (EAO) issued the Environmental Assessment Certificate which contains 32 conditions, the majority of which reflect current best practices for natural gas pipeline construction and operation.

In first quarter 2014, we commenced the phased filing of the B.C. Oil and Gas Commission applications required for the construction and operation of the pipeline facilities. Regulatory review of those applications is progressing on schedule, with permit decisions anticipated in first quarter 2015.

We are currently progressing the engineering design work to support the regulatory applications and refine the capital cost estimates for the final investment decision, which is expected to be made by LNG Canada in early 2016.

- *Prince Rupert Gas Transmission Project:* We continue to support information requests related to the regulatory applications with the B.C. EAO and B.C. Oil and Gas Commission. Work continues towards refining a capital cost estimate for the final investment decision, which is expected to be made by Pacific NorthWest LNG by the end of 2014.

Energy:

- *Genesee PPA Purchase:* In October 2014, we acquired a 100 megawatt (MW) energy contract from the Alberta Balancing Pool. The contract includes a monthly capacity payment for a three year term, commencing on November 1, 2014, and is derived from the 762 MW Genesee Power Purchase Arrangement held by the Alberta Balancing Pool.

- *Ravenswood:* In late September 2014, the 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings.
- *Ontario Solar:* In late September 2014, we completed the acquisition of three additional Ontario solar facilities for \$181 million. All power produced by the solar facilities is sold under 20-year contracts with the Ontario Power Authority.

Corporate:

- Our Board of Directors declared a quarterly dividend of \$0.48 per share for the quarter ending December 31, 2014 on TransCanada's outstanding common shares. The quarterly amount is equivalent to \$1.92 per common share on an annualized basis.

Teleconference – Audio and Slide Presentation:

We will hold a teleconference and webcast on Tuesday, November 4, 2014 to discuss our third quarter 2014 financial results. Russ Girling, TransCanada president and chief executive officer, and Don Marchand, executive vice-president and chief financial officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 9 a.m. (MT) / 11 a.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 November 11, 2014. Please call 800.408.3053 or 905.694.9451 and enter pass code 1306125.

The unaudited interim 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 60 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,500 kilometres (42,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with more than 400 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 11,800 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com or check us out on Twitter @TransCanada or <http://blog.transcanada.com>.

Forward Looking Information

This news release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no

obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to TransCanada's Quarterly Report to Shareholders dated November 3, 2014 and 2013 Annual Report on our website at www.transcanada.com or filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable EBITDA, funds generated from operations and comparable earnings per share, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated November 3, 2014.

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Quarterly report to shareholders

Third quarter 2014

Financial highlights

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Income				
Revenue	2,451	2,204	7,569	6,465
Net income attributable to common shares	457	481	1,285	1,292
per common share - basic and diluted	\$0.64	\$0.68	\$1.81	\$1.83
Comparable EBITDA ¹	1,387	1,257	4,000	3,568
Comparable earnings ¹	450	447	1,204	1,174
per common share ¹	\$0.63	\$0.63	\$1.70	\$1.66
Operating cash flow				
Funds generated from operations ¹	1,071	1,046	3,090	2,917
Decrease/(increase) in operating working capital	171	72	250	(252)
Net cash provided by operations	1,242	1,118	3,340	2,665
Investing activities				
Capital expenditures	(853)	(992)	(2,598)	(3,030)
Equity investments	(66)	(30)	(195)	(101)
Acquisitions	(181)	(99)	(181)	(154)
Proceeds from sale of assets, net of transaction costs	—	—	187	—
Dividends paid				
Per common share	\$0.48	\$0.46	\$1.44	\$1.38
Basic common shares outstanding (millions)				
Average for the period	708	707	708	707
End of period	709	707	709	707

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

Management's discussion and analysis

November 3, 2014

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2014, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2014 which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2013 audited consolidated financial statements and notes and the MD&A in our 2013 Annual Report, which have been prepared in accordance with U.S. GAAP.

About this document

Throughout this MD&A, the terms, *we*, *us*, *our* and *TransCanada* mean TransCanada Corporation and its subsidiaries.

Abbreviations and acronyms that are not defined in this MD&A are defined in the glossary in our 2013 Annual Report.

All information is as of November 3, 2014 and all amounts are in Canadian dollars, unless noted otherwise.

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 MD&A may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration 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 MD&A.

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 of our counterparties
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2013 Annual Report.

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

FOR MORE INFORMATION

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

NON-GAAP MEASURES

We use the following non-GAAP measures:

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

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

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting 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.

Comparable measures

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

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

Our decision not to include 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
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- write-downs of assets and investments.

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

Consolidated results - third quarter 2014

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Natural gas pipelines	484	436	1,566	1,383
Liquids pipelines ¹	226	152	613	443
Energy	359	370	832	812
Corporate	(37)	(30)	(107)	(89)
Total segmented earnings	1,032	928	2,904	2,549
Interest expense	(304)	(235)	(875)	(745)
Interest income and other	17	31	63	33
Income before income taxes	745	724	2,092	1,837
Income tax expense	(239)	(190)	(625)	(403)
Net income	506	534	1,467	1,434
Net income attributable to non-controlling interests	(25)	(33)	(110)	(87)
Net income attributable to controlling interests	481	501	1,357	1,347
Preferred share dividends	(24)	(20)	(72)	(55)
Net income attributable to common shares	457	481	1,285	1,292
Net income per common share - basic and diluted	\$0.64	\$0.68	\$1.81	\$1.83

1 Previously Oil Pipelines.

Net income attributable to common shares decreased by \$24 million for the three months ended September 30, 2014 compared to the same period in 2013. Net Income included unrealized gains and losses from changes in certain risk management activities. Excluding the impact of these items, comparable earnings in the three months ended September 30, 2014 increased slightly over the same period in 2013, as discussed below in Reconciliation of Net Income to Comparable Earnings.

Net income attributable to common shares decreased by \$7 million for the nine months ended September 30, 2014 compared to the same period in 2013. The 2014 results included:

- a gain on the sale of Cancarb Limited and its related power generation business of \$99 million after tax
- a net loss resulting from a termination payment to Niska Gas Storage for contract restructuring of \$32 million after tax
- unrealized gains and losses from changes in certain risk management activities.

The results for the first nine months of 2013 included \$84 million of Canadian Mainline net income related to 2012 resulting from an NEB decision in April 2013 (RH-003-2011) as well as a \$25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

The items discussed above are excluded from comparable earnings for the relevant periods. The remainder of net income is equivalent to comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

THIRD QUARTER 2014

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Net income attributable to common shares	457	481	1,285	1,292
Specific items (net of tax):				
Energy - Cancarb gain on sale	—	—	(99)	—
Energy - Niska contract termination	1	—	32	—
Risk management activities ¹	(8)	(34)	(14)	(9)
Natural gas pipelines - NEB decision - 2012	—	—	—	(84)
Part VI.I income tax adjustment	—	—	—	(25)
Comparable earnings	450	447	1,204	1,174
Net income per common share	\$0.64	\$0.68	\$1.81	\$1.83
Specific items (net of tax):				
Energy - Cancarb gain on sale	—	—	(0.14)	—
Energy - Niska contract termination	—	—	0.04	—
Risk management activities ¹	(0.01)	(0.05)	(0.01)	(0.01)
Natural gas pipelines - NEB decision - 2012	—	—	—	(0.12)
Part VI.I income tax adjustment	—	—	—	(0.04)
Comparable earnings per share	\$0.63	\$0.63	\$1.70	\$1.66

1 Risk management activities (unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Canadian Power	2	4	—	(2)
U.S. Power	41	31	30	14
Natural Gas Storage	7	2	4	3
Foreign exchange	(32)	15	(9)	—
Income tax attributable to risk management activities	(10)	(18)	(11)	(6)
Total gains from risk management activities	8	34	14	9

Comparable earnings increased by \$3 million for the three months ended September 30, 2014 compared to the same period in 2013. This was primarily the net effect of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- higher earnings from Mexico pipelines resulting from contract revenues recognized from the Tamazunchale Extension
- higher interest expense from debt issuances, higher foreign exchange on interest related to U.S. dollar-denominated debt and lower capitalized interest on projects placed in service
- lower earnings from Western Power as a result of lower realized power prices.

Comparable earnings increased by \$30 million or \$0.04 per share for the nine months ended September 30, 2014 compared to the same period in 2013. This was primarily the net effect of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from U.S. Power mainly because of higher realized capacity and power prices
- higher earnings from Mexico pipelines resulting from contract revenues recognized from the Tamazunchale Extension
- higher earnings from U.S. natural gas pipelines due to higher transportation revenues at Great Lakes and higher contributions from TC PipeLines, LP reflecting colder winter weather and increased demand
- higher interest expense from debt issuances, higher foreign exchange on interest related to U.S. dollar-denominated debt and lower capitalized interest on projects placed in service.

THIRD QUARTER 2014

The stronger U.S. dollar this quarter compared to the same period in 2013 positively impacted the translated results in our U.S. businesses, however this impact was mostly 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 net exposure through our hedging program.

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 cashflow.

Our capital program is comprised of \$17 billion of small to medium-sized projects and \$29 billion of large scale projects. Amounts presented exclude the impact of foreign exchange and capitalized interest. All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at September 30, 2014 (unaudited - billions of \$)	Segment	Expected In-Service Date	Estimated Project Cost	Amount Spent
Small to medium-sized projects				
Tamazunchale Extension ¹	Natural Gas Pipelines	2014	US 0.6	US 0.6
Ontario Solar	Energy	2014-2015	0.5	0.4
Houston Lateral and Terminal	Liquids Pipelines	2015	US 0.6	US 0.4
Heartland and TC Terminals	Liquids Pipelines	2016	0.9	0.1
Keystone Hardisty Terminal	Liquids Pipelines	²	0.3	0.1
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.6
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.1
Grand Rapids ³	Liquids Pipelines	2016-2017	1.5	0.2
Northern Courier	Liquids Pipelines	2017	0.8	0.1
Canadian Mainline - Eastern Mainline	Natural Gas Pipelines	2017	1.5	—
- Other	Natural Gas Pipelines	2015-2016	0.5	—
NGTL System - North Montney	Natural Gas Pipelines	2016-2017	1.7	0.1
- 2016/17 Facilities	Natural Gas Pipelines	2016-2017	2.7	—
- Merrick	Natural Gas Pipelines	2020	1.9	—
- Other	Natural Gas Pipelines	2014-2016	0.7	0.3
Napanee	Energy	2017 or 2018	1.0	—
			16.6	3.0
Large scale projects				
Keystone XL ⁴	Liquids Pipelines	²	US 8.0	US 2.4
Energy East ⁵	Liquids Pipelines	2018	12.0	0.3
Prince Rupert Gas Transmission	Natural Gas Pipelines	2018	5.0	0.3
Coastal GasLink	Natural Gas Pipelines	2018+	4.0	0.2
			29.0	3.2
			45.6	6.2

1 A force majeure has delayed completion of construction, however, revenue is being recorded from the original in service date of March 9, 2014 as per the terms of the Transportation Service Agreement.

2 Approximately two years from the date the Keystone XL permit is received.

3 Represents our 50 per cent share.

4 Estimated project cost dependent on the timing of the Presidential permit.

5 Excludes transfer of Canadian Mainline natural gas assets.

Outlook

The earnings outlook previously included in the 2013 Annual Report is expected to be impacted by:

- the gain on sale of Cancarb Limited and its related power generation facility
- the termination payment to Niska Gas Storage for the contract restructuring
- increased outage days at Bruce A.

We expect our capital expenditures to be \$4 billion for 2014, a decrease of \$1 billion from the outlook previously disclosed in our 2013 Annual Report.

See the MD&A in our 2013 Annual Report for further information about our outlook.

THIRD QUARTER 2014

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).

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable EBITDA	750	684	2,357	2,074
Comparable depreciation and amortization ¹	(266)	(248)	(791)	(733)
Comparable EBIT	484	436	1,566	1,341
Specific item:				
NEB decision - 2012	—	—	—	42
Segmented earnings	484	436	1,566	1,383

- 1 In 2014, comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization. In 2013, comparable depreciation and amortization for the nine months ended September 30, 2013 is adjusted by \$13 million relating to the impact of the NEB decision (RH-003-2011).

Natural Gas Pipelines segmented earnings increased by \$48 million and \$183 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. Natural Gas Pipelines segmented earnings for the nine months ended September 30, 2013 included \$42 million related to the 2012 impact of the NEB decision (RH-003-2011). This amount has been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT and comparable EBITDA and are discussed below.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Canadian Pipelines				
Canadian Mainline	311	273	938	816
NGTL System	213	210	637	585
Foothills	26	29	80	86
Other Canadian pipelines (TQM ¹ , Ventures LP)	7	7	17	20
Canadian Pipelines - comparable EBITDA	557	519	1,672	1,507
Comparable depreciation and amortization	(206)	(191)	(613)	(565)
Canadian Pipelines - comparable EBIT	351	328	1,059	942
U.S. and International Pipelines (US\$)				
ANR	31	33	142	155
TC PipeLines, LP ^{1,2}	18	21	65	51
Great Lakes ³	8	6	36	24
Other U.S. pipelines (Bison ⁴ , Iroquois ¹ , GTN ⁴ , Portland ⁵)	26	26	100	146
Mexico (Guadalajara, Tamazunchale)	43	25	117	77
International and other ^{1,6}	(3)	3	(5)	(3)
Non-controlling interests ⁷	49	52	176	126
U.S. and International Pipelines - comparable EBITDA	172	166	631	576
Comparable depreciation and amortization	(54)	(55)	(162)	(164)
U.S. and International Pipelines - comparable EBIT	118	111	469	412
Foreign exchange impact	10	4	44	8
U.S. and International Pipelines - comparable EBIT (Cdn\$)	128	115	513	420
Business Development comparable EBITDA and EBIT	5	(7)	(6)	(21)
Natural Gas Pipelines - comparable EBIT	484	436	1,566	1,341

THIRD QUARTER 2014

- 1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.
- 2 Beginning in August 2014, TC PipeLines, LP began its at-the-market equity issuance program which will decrease our ownership interest in TC PipeLines, LP going forward. Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	September 30, 2014	July 1, 2013	May 22, 2013	January 1, 2013
TC PipeLines, LP	28.3	28.9	28.9	33.3
Effective ownership through TC PipeLines, LP:				
GTN/Bison	19.8	20.2	7.2	8.3
Great Lakes	13.2	13.4	13.4	15.5

- 3 Represents our 53.6 per cent direct ownership interest.
- 4 Effective July 1, 2013, represents our 30 per cent direct ownership interest. Prior to July 1, 2013, our direct ownership interest was 75 per cent.
- 5 Represents our 61.7 per cent ownership interest.
- 6 Includes our share of the equity income from Gas Pacifico/INNERGY and TransGas as well as general and administration costs relating to our U.S. and International Pipelines.
- 7 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 affected by the approved ROE, investment base, level of deemed common equity, carrying charges accrued to shippers on the Tolls Stabilization Account (TSA), and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA and comparable EBIT but do not impact net income as they are recovered in revenue on a flow-through basis.

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Canadian Mainline - net income	61	67	185	285
Canadian Mainline - comparable earnings	61	67	185	201
NGTL System	61	57	182	171
Foothills	5	4	13	13

Net income for the Canadian Mainline decreased by \$6 million and \$100 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. Net income in first quarter 2013 included \$84 million related to the 2012 impact of the NEB decision (RH-003-2011), which was excluded from comparable earnings. Comparable earnings in both years reflect an ROE of 11.50 per cent on deemed common equity of 40 per cent and have decreased by \$6 million and \$16 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 because of a lower average investment base as well as carrying charges accrued to shippers on the positive TSA.

Net income for the NGTL System increased by \$4 million and \$11 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. A higher average investment base as well as an increase in the ROE had a positive impact on earnings. These increases were partially offset by increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. The Settlement included an ROE of 10.10 per cent on deemed common equity of 40 per cent and included annual fixed amounts for certain OM&A costs. Results for the three and nine months ended September 30, 2013 reflect the previously approved ROE of 9.70 per cent on deemed common equity of 40 per cent.

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 the U.S. and international pipelines increased by US\$6 million and US\$55 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. This was the net effect of:

- contract revenues recognized from the Tamazunchale Extension from the original in-service date of March 9, 2014. The Tamazunchale Extension project has experienced delays in completing construction due to archeological findings along the pipeline route. The CFE agreed that, under the terms of the TSA, these delays constitute force majeure and, as a result, collection and recognition of revenue commenced on March 9, 2014.
- higher transportation revenues at Great Lakes mainly due to colder winter weather and increased demand.
- higher OM&A costs at ANR as well as lower storage revenues.

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

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by \$18 million and \$58 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 mainly because of a higher investment base and higher depreciation rates on the NGTL System.

BUSINESS DEVELOPMENT

Business development expenses were lower by \$12 million and \$15 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 mainly due to recovery of amounts from partners for 2013 *Alaska Gasline Inducement Act* costs in 2014 and lower general and administrative expenses.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

nine months ended September 30 (unaudited)	Canadian Mainline ¹		NGTL System ²		ANR ³	
	2014	2013	2014	2013	2014	2013
Average investment base (millions of \$)	5,632	5,855	6,205	5,913	n/a	n/a
Delivery volumes (Bcf)						
Total	1,264	992	2,857	2,658	1,202	1,182
Average per day	4.6	3.6	10.5	9.7	4.4	4.3

- 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 nine months ended September 30, 2014 were 940 Bcf (2013 – 547 Bcf). Average per day was 3.5 Bcf (2013 – 2.0 Bcf).
- 2 Field receipt volumes for the NGTL System for the nine months ended September 30, 2014 were 2,857 Bcf (2013 – 2,748 Bcf). Average per day was 10.5 Bcf (2013 – 10.1 Bcf).
- 3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

Liquids Pipelines¹

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable EBITDA	281	189	771	554
Comparable depreciation and amortization ²	(55)	(37)	(158)	(111)
Comparable EBIT	226	152	613	443
Specific items	—	—	—	—
Segmented earnings	226	152	613	443

1 Previously Oil Pipelines.

2 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.

Liquids Pipelines segmented earnings increased by \$74 million and \$170 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. Liquids Pipelines segmented earnings are equivalent to comparable EBIT and comparable EBITDA and are discussed below.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Keystone Pipeline System	275	193	779	566
Liquids Pipelines Business Development	6	(4)	(8)	(12)
Liquids Pipelines - comparable EBITDA	281	189	771	554
Comparable depreciation and amortization	(55)	(37)	(158)	(111)
Liquids Pipelines - comparable EBIT	226	152	613	443

Comparable EBIT denominated as follows:				
Canadian dollars	58	50	157	149
U.S. dollars	155	98	417	287
Foreign exchange impact	13	4	39	7
	226	152	613	443

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 \$82 million and \$213 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. These increases were primarily due to:

- incremental earnings from the Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

BUSINESS DEVELOPMENT

Business development expenses for the three and nine months ended September 30, 2014 were \$10 million and \$4 million lower than the same periods in 2013 mainly due to lower general and administrative expenses and an increased focus on capital projects.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by \$18 million and \$47 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 due to the Gulf Coast extension being placed in service.

Energy

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable EBITDA	387	410	963	1,017
Comparable depreciation and amortization ¹	(76)	(77)	(230)	(220)
Comparable EBIT	311	333	733	797
Specific items (pre-tax):				
Cancarb gain on sale	—	—	108	—
Niska contract termination	(2)	—	(43)	—
Risk management activities	50	37	34	15
Segmented earnings	359	370	832	812

1 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.

Energy segmented earnings decreased by \$11 million for the three months ended September 30, 2014 and increased by \$20 million for the nine months ended September 30, 2014 compared to the same periods in 2013.

Energy segmented earnings included the following specific items:

- a gain of \$108 million (\$99 million after tax) on the sale of Cancarb Limited and its related power generation business, which closed on April 15, 2014
- a net loss resulting from the contract termination payment to Niska Gas Storage of \$43 million (\$32 million after-tax) effective April 30, 2014
- unrealized gains and 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 (unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Canadian Power	2	4	—	(2)
U.S. Power	41	31	30	14
Natural Gas Storage	7	2	4	3
Total gains from risk management activities	50	37	34	15

THIRD QUARTER 2014

The remainder of the Energy segmented earnings are equivalent to comparable EBITDA and comparable EBIT and are discussed below.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable EBITDA	387	410	963	1,017
Comparable depreciation and amortization ¹	(76)	(77)	(230)	(220)
Comparable EBIT	311	333	733	797
Canadian Power				
Western Power	75	113	193	304
Eastern Power ¹	76	72	239	231
Bruce Power	111	105	199	195
Canadian Power - comparable EBITDA²	262	290	631	730
Comparable depreciation and amortization	(44)	(43)	(133)	(129)
Canadian Power - comparable EBIT²	218	247	498	601
U.S. Power (US\$)				
U.S. Power - comparable EBITDA	117	111	291	258
Comparable depreciation and amortization	(26)	(29)	(80)	(80)
U.S. Power - comparable EBIT	91	82	211	178
Foreign exchange impact	8	3	19	5
U.S. Power - comparable EBIT (Cdn\$)	99	85	230	183
Natural Gas Storage and other				
Natural Gas Storage and other - comparable EBITDA	3	9	32	36
Comparable depreciation and amortization	(3)	(4)	(9)	(9)
Natural Gas Storage and other - comparable EBIT	—	5	23	27
Business Development comparable EBITDA and EBIT	(6)	(4)	(18)	(14)
Energy - comparable EBIT²	311	333	733	797

1 Includes four Ontario solar facilities acquired between June and December 2013. Three additional solar facilities were acquired at the end of September 2014.

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

Comparable EBITDA for Energy decreased by \$23 million and \$54 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 due to:

- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from U.S. Power mainly because of higher realized capacity prices
- incremental earnings from Ontario solar facilities acquired in 2013.

Results for the nine months ended September 30, 2014 were also impacted by higher realized power prices at U.S. Power.

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

THIRD QUARTER 2014

CANADIAN POWER**Western and Eastern Power**

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Revenue¹				
Western Power	206	142	547	439
Eastern Power ²	92	96	322	296
Other ³	—	21	57	74
	298	259	926	809
Income from equity investments ⁴	14	38	42	126
Commodity purchases resold	(105)	(39)	(296)	(189)
Plant operating costs and other	(54)	(69)	(240)	(213)
Exclude risk management activities ¹	(2)	(4)	—	2
Comparable EBITDA	151	185	432	535
Comparable depreciation and amortization	(44)	(43)	(133)	(129)
Comparable EBIT	107	142	299	406

Breakdown of comparable EBITDA				
Western Power	75	113	193	304
Eastern Power	76	72	239	231
Comparable EBITDA	151	185	432	535

- 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 are excluded to arrive at Comparable EBITDA.
- 2 Includes four Ontario solar facilities acquired between June and December 2013. Three additional solar facilities were acquired at the end of September 2014.
- 3 Includes sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black. Cancarb was sold on April 15, 2014.
- 4 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.

THIRD QUARTER 2014

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

(unaudited)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Sales volumes (GWh)				
Supply				
Generation				
Western Power	637	680	1,857	2,037
Eastern Power ¹	563	872	2,436	2,968
Purchased				
Sundance A & B and Sheerness PPAs ²	2,791	1,957	8,189	5,452
Other purchases	2	1	9	1
	3,993	3,510	12,491	10,458
Sales				
Contracted				
Western Power	2,585	1,846	7,480	5,492
Eastern Power ¹	563	872	2,436	2,968
Spot				
Western Power	845	792	2,575	1,998
	3,993	3,510	12,491	10,458
Plant availability³				
Western Power ⁴	96%	94%	95%	94%
Eastern Power ^{1,5}	99%	94%	90%	90%

- 1 Includes four Ontario solar facilities acquired between June and December 2013. Three additional solar facilities were acquired at the end of September 2014.
- 2 Sundance A Unit 1 returned to service in September 2013 and Unit 2 returned to service in October 2013.
- 3 The percentage of time the plant was available to generate power, regardless of whether it was running.
- 4 Does not include facilities that provide power to TransCanada under PPAs.
- 5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Comparable EBITDA for Western Power decreased by \$38 million and \$111 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of the Sundance A PPA Unit 1 in September 2013 and Unit 2 in October 2013 which also resulted in increased volume purchases
- sale of Cancarb in April 2014.

Average spot market power prices in Alberta decreased by 24 per cent from \$84/MWh to \$64/MWh for the three months ended September 30, 2014 and 38 per cent from \$90/MWh to \$56/MWh for the nine months ended September 30, 2014, compared to the same periods in 2013. Strong coal fleet availability and new wind capacity in the Alberta market have resulted in significantly lower prices despite strong growth in Alberta power demand. 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.

Seventy-five per cent of Western Power sales volumes were sold under contract in third quarter 2014 and 70 per cent in third quarter 2013.

Eastern Power

Comparable EBITDA for Eastern Power increased by \$4 million and \$8 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 mainly due to the incremental earnings from the four Ontario solar facilities acquired in 2013. Comparable EBITDA for the nine months ended September 30, 2014 was also impacted by lower earnings from Halton Hills.

BRUCE POWER

Our proportionate share

(unaudited - millions of \$, unless noted otherwise)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Income from equity investments¹				
Bruce A	62	45	109	132
Bruce B	49	60	90	63
	111	105	199	195
Comprised of:				
Revenues	330	322	895	916
Operating expenses	(140)	(129)	(461)	(473)
Depreciation and other	(79)	(88)	(235)	(248)
	111	105	199	195
Bruce Power - Other information				
Plant availability ²				
Bruce A	83%	81%	76%	78%
Bruce B	99%	99%	92%	85%
Combined Bruce Power	91%	91%	84%	82%
Planned outage days				
Bruce A	34	—	118	123
Bruce B	—	—	74	140
Unplanned outage days				
Bruce A	25	37	130	45
Bruce B	—	1	—	13
Sales volumes (GWh) ¹				
Bruce A	2,512	2,566	7,076	7,127
Bruce B	2,152	2,187	6,124	5,647
	4,664	4,753	13,200	12,774
Realized sales price per MWh ³				
Bruce A	\$72	\$71	\$72	\$70
Bruce B	\$55	\$55	\$55	\$54
Combined Bruce Power	\$62	\$62	\$62	\$61

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

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

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

Equity income from Bruce A increased by \$17 million for the three months ended September 30, 2014 compared to the same period in 2013. The increase was mainly due to lower depreciation and operating expenses. The negative impact of increased outage days was generally offset by higher generation levels while operating.

Equity income from Bruce A decreased by \$23 million for the nine months ended September 30, 2014 compared to the same period in 2013 mainly due to:

- lower earnings from Unit 3 due to a planned outage which began in April 2014 and was completed in early August 2014
- lower volumes due to increased unplanned outage days, primarily on Units 1 and 2.

These decreases were partially offset by higher earnings from Unit 4 following the completion of the planned life extension outage which began in third quarter 2012 and was completed in April 2013.

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Equity income from Bruce B decreased \$11 million for the three months ended September 30, 2014 compared to the same period in 2013 mainly due to higher lease expense recognized in third quarter 2014 based on the terms of the lease agreement with Ontario Power Generation.

Equity income from Bruce B increased \$27 million for the nine months ended September 30, 2014 compared to the same period in 2013 mainly due to higher volumes and lower operating costs resulting from fewer planned and unplanned outage days, partially offset by higher lease expense.

Under the contract with the OPA, all of the output from Bruce A Units 1 to 4 is sold at a fixed price per MWh. The fixed price is adjusted annually on April 1 for inflation and other provisions under the OPA contract. Bruce A also recovers fuel costs from the OPA.

Bruce A fixed price	per MWh
April 1, 2014 - March 31, 2015	\$71.70
April 1, 2013 - March 31, 2014	\$70.99
April 1, 2012 - March 31, 2013	\$68.23

Under the same contract, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price	per MWh
April 1, 2014 - March 31, 2015	\$52.86
April 1, 2013 - March 31, 2014	\$52.34
April 1, 2012 - March 31, 2013	\$51.62

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the average spot price in a month exceeds the floor price. While the first quarter 2014 average spot price exceeded the floor price, spot prices have since fallen below the floor price and are expected to remain there for the remainder of 2014. As a result, Bruce B is expected to recognize annual revenues at the floor price and amounts equivalent to that received above the floor in first quarter 2014 are expected to be repaid to the OPA in early 2015.

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

The overall plant availability percentage in 2014 is expected to be in the high 70s for Bruce A and high 80s for Bruce B. Bruce B Unit 5 was removed from service early in October 2014 for a planned maintenance outage which is scheduled for approximately two months.

U.S. POWER

(unaudited - millions of US\$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Revenue				
Power ¹	439	437	1,493	1,216
Capacity	112	93	278	217
	551	530	1,771	1,433
Commodity purchases resold	(260)	(249)	(1,027)	(752)
Plant operating costs and other ²	(137)	(139)	(426)	(409)
Exclude risk management activities ¹	(37)	(31)	(27)	(14)
Comparable EBITDA	117	111	291	258
Comparable depreciation and amortization	(26)	(29)	(80)	(80)
Comparable EBIT	91	82	211	178

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

Sales volumes and plant availability

(unaudited)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Physical sales volumes (GWh)				
Supply				
Generation	2,918	2,209	6,162	5,021
Purchased	3,020	2,385	7,714	6,742
	5,938	4,594	13,876	11,763
Plant availability¹	94%	94%	89%	88%

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

Comparable EBITDA for U.S. Power increased US\$6 million for the three months ended September 30, 2014 compared to the same period in 2013. The increase was the net effect of:

- higher realized capacity prices in New York
- higher generation at our Ravenswood facility offset by lower realized power prices
- higher costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers
- lower generation and lower realized power prices at our hydro facilities.

Comparable EBITDA for U.S. Power increased US\$33 million for the nine months ended September 30, 2014 compared to the same period in 2013. The increase was the net effect of:

- higher realized capacity prices in New York
- higher realized power prices and higher generation at our Ravenswood facility offset by higher fuel prices
- higher realized power prices in New England
- higher prices and related costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers.

Wholesale electricity prices in New York and New England were lower for the three months ended September 30, 2014 compared to the same period in 2013 primarily due to cooler summer temperatures. Wholesale electricity prices in New York and New England were higher for the nine months ended September 30, 2014 compared to the same period in 2013 primarily due to significantly higher spot power prices in first quarter 2014. Colder winter temperatures and gas transmission constraints resulted in higher natural gas prices in the predominantly gas-fired New England and New York power markets in first quarter 2014 compared to the same period in 2013.

Average spot power prices for the three months ended September 30, 2014 in New England of US\$34/MWh were 20 per cent lower and in New York City spot power prices decreased 34 per cent to an average of US\$34/MWh compared to the same period in 2013. Average spot power prices for the nine months ended September 30, 2014 in New England increased 29 per cent to US\$73/MWh and in New York City spot power prices increased 20 per cent to an average of US\$66/MWh compared to the same period in 2013.

Average spot capacity prices in New York City of US\$18 and US\$15 per kilowatt-month were on average 17 per cent and 32 per cent higher for the three and nine months ended September 30, 2014 compared to the same periods in 2013. This, and the impact of hedging activities, resulted in higher realized capacity prices in New York compared to the same period in 2013.

Physical sales volumes for the three and nine months ended September 30, 2014 were higher than the same periods in 2013. For the three months ended September 30, 2014, generation volumes at our Ravenswood facility and purchased volumes sold to wholesale, commercial and industrial customers were higher than the same period in 2013. For the nine months ended September 30, 2014, generation at our Ravenswood and Kibby facilities and

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purchased volumes sold to wholesale, commercial and industrial customers were also higher than in the same period in 2013.

As at September 30, 2014, approximately 1,500 GWh or 70 per cent of U.S. Power's planned generation was contracted for the remainder of 2014, and 3,500 GWh or 35 per cent for 2015. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA decreased \$6 million and \$4 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. The decrease was primarily due to lower realized natural gas storage spreads. The seasonal nature of natural gas storage generally results in higher revenues in the winter season.

Recent developments

NATURAL GAS PIPELINES

Canadian Regulated Pipelines

NGTL System

We continue to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern B.C. from unconventional gas plays and substantive growth in intra-basin delivery markets. This is driven primarily by oil sands development and demand for gas-fired electric power generation. This demand for NGTL System services is expected to result in approximately 4.0 Bcf/d of incremental firm receipt and firm delivery services. Approximately 3.1 Bcf/d relates to firm receipt services and 0.9 Bcf/d relates to firm delivery services. As a result, following NEB approval, we will be constructing new facilities to meet these service requests of approximately 540 km (336 miles) of pipeline, seven compressor stations, and 40 meter stations which will be required in 2016 and 2017 (2016/17 Facilities). The estimated total capital costs for the facilities is approximately \$2.7 billion.

Approximately \$285 million of capital projects have been placed in service in the nine months ended September 30, 2014. Including the new 2016/17 Facilities capital requirements, we have approximately \$6.7 billion of projects in development or under construction, which have been or will be filed with the NEB for approval. This includes the North Montney Mainline and the Merrick Mainline Pipeline, along with other new supply and demand facilities.

North Montney Mainline Project

The NEB issued a Hearing Order in February 2014 for the \$1.7 billion North Montney Pipeline Project, which is an extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. The proposed project consists of approximately 300 km (186 miles) of pipeline and is expected to be in service in two sections, Aitken Creek in second quarter 2016 and Kahta in second quarter 2017.

On June 17, 2014, the NEB revised the procedural schedule which has resulted in the oral portion of the hearing being rescheduled. The Calgary phase began October 14, 2014 and the Fort St. John phase is to be begin in mid-November. We now anticipate an NEB decision on the application in first quarter 2015.

Merrick Mainline Pipeline Project

On June 4, 2014, we announced the signing of agreements for approximately 1.9 Bcf/d of firm natural gas transportation services to underpin the development of a major extension of our NGTL System.

The proposed Merrick Mainline Pipeline Project will transport natural gas sourced through the NGTL System to the inlet of a proposed Pacific Trail Pipeline that will terminate at the Kitimat LNG Terminal at Bish Cove near Kitimat, B.C. The proposed project will be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C. The \$1.9 billion project consists of approximately 260 km (161 miles) of 48-inch diameter pipe.

The filing of the application for approvals to build and operate the system with the NEB is under review and is likely to be delayed to first quarter 2015. Subject to the necessary approvals, including a positive final investment decision for the Kitimat LNG project, we expect the Merrick Mainline to be in service in first quarter 2020.

2015 Revenue Requirement Settlement

We have reached a revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include no changes to the return on equity of 10.10 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed operating, maintenance and administrative expense amount. The settlement was filed with the NEB on October 31, 2014.

Canadian Mainline

LDC Settlement

In March 2014, the NEB responded to the LDC Settlement application we filed in December 2013. The NEB did not approve the application as a settlement but allowed us the option to continue with the application as a contested tolls application, amend the application or terminate the processing of the application. We amended the application with additional information. In May 2014, the NEB released a Hearing Order that set out a hearing process and schedule for the 2015 - 2030 Mainline Tolls application that incorporates the LDC Settlement. The hearing concluded September 25, 2014 and we anticipate a decision from the NEB before the end of 2014.

Eastern Mainline Project

In May 2014, we filed a project description with the NEB for the Eastern Mainline Project. On October 30, 2014 we filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario. The new facilities are a result of the proposed transfer of a portion of the Canadian Mainline capacity to crude oil from natural gas service as part of our Energy East Pipeline and an open season that closed in January 2014. The \$1.5 billion capital project will add 0.6 Bcf/d of new capacity and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments in the Eastern Triangle segment of the Canadian Mainline. Subject to regulatory approvals, the project is expected to be in service by second quarter 2017.

Other Canadian Mainline Expansions

In addition to the Eastern Mainline Project, we have executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new, or modifications to existing facilities with a total capital cost estimate of \$475 million. Approximately \$255 million of these projects have an expected in-service date of November 1, 2015 including the Kings North Connection, Parkway West Connection and the Hamilton Area Project. The Vaughan Loop and compressor station piping modifications, with a capital cost of approximately \$220 million, have an expected in-service date of November 1, 2016. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in Eastern Canada.

U.S. Pipelines

Sale of Bison Pipeline to TC PipeLines, LP

On October 1, 2014, we closed the sale of our remaining 30 per cent interest in Bison Pipeline LLC to TC PipeLines, LP for cash proceeds of US\$215 million plus purchase price adjustments.

At September 30, 2014, we held a 28.3 per cent interest in TC PipeLines, LP for which we are the General Partner.

ANR Pipeline

We have secured almost 2.0 Bcf/d of firm natural gas transportation commitments on the ANR Pipeline's Southeast Main Line at maximum rates for an average term of 23 years. Approximately 1.25 Bcf/d of new contracts will commence in late 2014 including volume commitments from the ANR Lebanon Lateral Reversal project, with the remaining volume commencing in 2015. These contracts will enable growing Utica and Marcellus shale gas supply to move to both northern delivery points and southbound to the U.S. Gulf Coast. As a result, approximately US\$100 million of capital investment will be required to bring this additional supply to market.

Mexican Pipelines

Tamazunchale Pipeline Extension Project

Construction of the US\$600 million extension is now expected to be completed in fourth quarter 2014 with delays attributed to archeological findings along the pipeline route. Under the terms of the Transportation Service Agreement, these delays are recognized as a force majeure with provisions allowing for collection of revenue as per the original service commencement of March 9, 2014.

LNG Pipeline Projects

Coastal GasLink

On October 24, 2014, the B.C. EAO issued the Environmental Assessment Certificate which contains 32 conditions, the majority of which reflect current best practices for natural gas pipeline construction and operation.

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In first quarter 2014 we commenced the phased filing of the B.C. Oil and Gas Commission applications required for the construction and operation of the pipeline facilities. Regulatory review of those applications is progressing on schedule, with permit decisions anticipated in first quarter 2015.

We are currently progressing the engineering design work to support the regulatory applications and refine the capital cost estimates for the final investment decision which is expected to be made by LNG Canada in early 2016.

Prince Rupert Gas Transmission

We continue to support information requests related to the regulatory applications with the B.C. EAO and B.C. Oil and Gas Commission. Work continues towards refining a capital cost estimate for the final investment decision which is expected to be made by Pacific NorthWest LNG by the end of 2014.

Alaska

On July 16, 2014, the producers filed an export permit application with the U.S. Department of Energy for the right to export 20 million tonnes per annum of liquefied natural gas for 30 years. On September 12, 2014, the FERC approved the National Environmental Policy Act (NEPA) pre-file request jointly made by us, the three major Alaska North Slope producers and Alaska Gasline Development Corp. This approval triggers the NEPA environmental review process, which includes a series of community consultations.

LIQUIDS PIPELINES

Keystone Pipeline System

In early 2014, we completed construction of the 780 km (485 mile) Gulf Coast extension of the Keystone Pipeline System, from Cushing, Oklahoma to the U.S. Gulf Coast. Crude oil transportation service on the project began January 22, 2014.

Keystone XL

On January 31, 2014, the DOS released its Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. On April 18, 2014, the DOS announced that the National Interest Determination period has been extended indefinitely to allow them to consider the potential impact of the case discussed below on the Nebraska portion of the pipeline route.

In February 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL project. Nebraska's Attorney General has filed an appeal and the Nebraska State Supreme Court heard the appeal on September 5, 2014. It is unknown when the Nebraska State Supreme Court will release its decision.

On September 15, 2014, we filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (PUC). This certification confirms that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted persist. It is unknown when the South Dakota PUC will release its decision.

Due to continued delays in acquiring U.S. regulatory approvals and increasing regulatory conditions, the estimated capital costs for the Keystone XL project have increased from US\$5.4 billion as provided in the DOS regulatory filing to approximately US\$8.0 billion. As of September 30, 2014, we have invested US\$2.4 billion in the Keystone XL project.

Cushing Marketlink

In September 2014, we completed construction on the Cushing Marketlink receipt facilities at Cushing, Oklahoma. Cushing Marketlink will facilitate the transportation of crude oil from the market hub at Cushing to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System.

Energy East Pipeline

In March 2014, we filed the project description for the Energy East Pipeline with the NEB. This is the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline. The project is estimated to cost approximately \$12 billion, excluding the transfer value of Canadian Mainline natural gas assets.

We continue to participate in Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning.

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On October 30, 2014, we filed the necessary regulatory applications for approvals to construct and operate the pipeline project and terminal facilities with the NEB. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries to Québec and New Brunswick by the end of 2018.

Heartland Pipeline and TC Terminals

The Heartland Pipeline and TC Terminals will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. In February 2014, the application for the terminal facility was approved by the Alberta Energy Regulator.

Grand Rapids Pipeline

On October 9, 2014, the Alberta Energy Regulator (AER) issued a permit approving the majority of our application to construct and operate the Grand Rapids Pipeline. Construction is expected to begin in fall 2014, with the system expected to be in service in multiple stages with initial crude oil service by mid-2016 and full completion in 2017.

Northern Courier Pipeline

In October 2013, Suncor Energy announced that Fort Hills Energy LP is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project will transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.

In July 2014, the AER issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has commenced and the pipeline is expected to be in service in 2017.

ENERGY**Ontario Solar**

At the end of September 2014, we completed the acquisition of three additional Ontario solar facilities for \$181 million. All power produced by the solar facilities will be sold under 20-year PPAs with the OPA.

Ravenswood

In late September 2014, the 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, net of deductibles, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings.

Genesee

In October 2014, we acquired a 100MW energy contract from the Alberta Balancing Pool. The contract includes a monthly capacity payment for a three year term, commencing on November 1, 2014, and is derived from the 762 MW Genesee Power Purchase Arrangement (PPA) held by the Alberta Balancing Pool.

Cancarb Limited and Cancarb Waste Heat Facility

The sale of Cancarb Limited and its related power generation facility closed in April 2014 for gross proceeds of \$190 million. We recognized a gain of \$99 million, net of tax, in second quarter 2014.

Natural Gas Storage

Effective April 30, 2014, we terminated a 38 Bcf long-term natural gas storage contract in Alberta with Niska Gas Storage. The contract contained provisions allowing for possible early termination. As a result, we recorded an after tax charge of \$32 million in 2014. We have re-contracted for new natural gas storage services in Alberta with Niska Gas Storage starting May 1, 2014 for a six-year period and a reduced average volume.

Other income statement items

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian-dollar denominated	(108)	(127)	(335)	(372)
U.S. dollar-denominated (US\$)	(215)	(188)	(638)	(561)
Foreign exchange impact	(19)	(7)	(60)	(13)
	(342)	(322)	(1,033)	(946)
Other interest and amortization expense	(19)	7	(41)	7
Capitalized interest	57	80	199	195
Comparable interest expense	(304)	(235)	(875)	(744)
Specific item:				
NEB decision - 2012	—	—	—	(1)
Interest expense	(304)	(235)	(875)	(745)

Comparable interest expense increased by \$69 million and \$131 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 because of the following:

- higher interest expense due to debt issues of:
 - US\$1.25 billion in February 2014
 - US\$1.25 billion in October 2013
 - US\$500 million in July 2013
 - \$750 million in July 2013
 - US\$500 million in July 2013 by TC PipeLines, LP
 - partially offset by Canadian and U.S. dollar-denominated debt maturities
- higher foreign exchange on interest expense related to U.S. denominated debt
- lower capitalized interest due to the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014 offset by higher capitalized interest primarily for Keystone XL.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable interest income and other	49	16	72	32
Specific items (pre-tax):				
NEB decision - 2012	—	—	—	1
Risk management activities	(32)	15	(9)	—
Interest income and other	17	31	63	33

Comparable interest income and other increased by \$33 million and \$40 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. This is the result of increased AFUDC related to our rate-regulated projects, including Energy East Pipeline and Mexico pipelines, offset by higher realized losses in 2014 compared to 2013 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income and the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

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(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable income tax expense	(230)	(172)	(616)	(464)
Specific items:				
Cancarb gain on sale	—	—	(9)	—
Niska contract termination	1	—	11	—
NEB decision - 2012	—	—	—	42
Part VI.I income tax adjustment	—	—	—	25
Risk management activities	(10)	(18)	(11)	(6)
Income tax expense	(239)	(190)	(625)	(403)

Comparable income tax expense increased by \$58 million and \$152 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. The increase was mainly the result of higher pre-tax earnings in 2014 compared to 2013, changes in the proportion of income earned between Canadian and foreign jurisdictions as well as higher flow-through taxes in 2014 on Canadian regulated pipelines.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Net income attributable to non-controlling interests	(25)	(33)	(110)	(87)
Preferred share dividends	(24)	(20)	(72)	(55)

Net income attributable to non-controlling interests decreased by \$8 million for the three months ended September 30, 2014 compared to the same period in 2013 primarily due to the redemption of Series U preferred shares in October 2013 and Series Y preferred shares in March 2014.

Net income attributable to non-controlling interests increased by \$23 million for the nine months ended September 30, 2014 compared to the same period in 2013 primarily due to the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP in July 2013 partially offset by the redemption of Series U preferred shares in October 2013 and Series Y preferred shares in March 2014.

Preferred share dividends increased by \$4 million and \$17 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013. The three month variance is due to the issuance of Series 9 preferred shares in January 2014 and the nine month variance is due to the issuances of Series 7 preferred shares in March 2013 and Series 9 preferred shares in January 2014.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of an economic cycle, and rely on our cash flow from operations to sustain our business, pay dividends and fund a portion of our growth.

We believe we have the capacity to fund our existing capital program through predictable cash flow from operations, access to capital markets, cash on hand and substantial committed credit facilities.

We access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

CASH PROVIDED BY OPERATING ACTIVITIES

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Funds generated from operations ¹	1,071	1,046	3,090	2,917
Decrease/(increase) in operating working capital	171	72	250	(252)
Net cash provided by operations	1,242	1,118	3,340	2,665

1 See the non-GAAP measures section in this MD&A for further discussion of funds generated from operations.

Net cash provided by operations increased by \$124 million and \$675 million for the three and nine months ended September 30, 2014 compared to the same periods in 2013 primarily due to changes in our operating working capital.

At September 30, 2014, our current assets were \$3.4 billion and current liabilities were \$6.6 billion, leaving us with a working capital deficit of \$3.2 billion compared to \$2.2 billion at December 31, 2013. This working capital deficiency is considered to be in the normal course of business and is managed through our ability to generate cash flow from operations and our ongoing access to the capital markets.

CASH (USED IN)/PROVIDED BY INVESTING ACTIVITIES

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Capital expenditures	(853)	(992)	(2,598)	(3,030)
Equity investments	(66)	(30)	(195)	(101)
Acquisitions	(181)	(99)	(181)	(154)
Proceeds from sale of assets, net of transaction costs	—	—	187	—

Capital expenditures in 2014 were primarily related to the construction of Mexico pipelines, expansion of the NGTL System, and construction of the Houston Lateral and Tank Terminals.

Equity investments have increased year-over-year primarily due to our investment in Grand Rapids.

In September 2014, we completed the acquisition of three additional Ontario solar facilities for \$181 million.

In April 2014, we closed the sale of Cancarb Limited for \$187 million, net of transaction costs.

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CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Long-term debt issued, net of issue costs	—	2,173	1,380	2,917
Long-term debt repaid	(38)	(521)	(1,020)	(1,230)
Notes payable issued/(repaid), net	377	(1,177)	(145)	(618)
Dividends and distributions paid	(406)	(390)	(1,208)	(1,126)
Common shares issued, net of issue costs	27	4	43	59
Partnership units of subsidiary issued, net of issue costs	79	—	79	384
Preferred shares issued, net of issue costs	—	—	440	585
Preferred shares of subsidiary redeemed	—	—	(200)	—

LONG-TERM DEBT ISSUED

Amount (unaudited - millions of \$)	Type	Maturity date	Interest rate	Date issued
US\$1,250	Senior unsecured notes	March 1, 2034	4.625%	February 2014

LONG-TERM DEBT RETIRED

Amount (unaudited - millions of \$)	Type	Retirement date	Interest rate
\$450	Medium term notes	January 2014	5.65%
\$300	Medium term notes	February 2014	5.05%
\$125	Debenture	June 2014	11.10%
\$53	Debenture	June 2014	11.20%

PREFERRED SHARE ISSUANCE AND REDEMPTION

In January 2014, we completed a public offering of 18 million Series 9 cumulative redeemable first preferred shares at \$25 per share resulting in gross proceeds of \$450 million. Investors are entitled to receive fixed cumulative dividends at an annual rate of \$1.0625 per share, payable quarterly. The dividend rate will reset on October 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 2.35 per cent. The preferred shares are redeemable by us on or after October 30, 2019 and on October 30 of every fifth year thereafter at a price of \$25 per share plus accrued and unpaid dividends. Investors will have the right to convert their shares into Series 10 cumulative redeemable first preferred shares on October 30, 2019 and on October 30 of every fifth year thereafter. The holders of Series 10 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the then 90-day Government of Canada treasury bill rate and 2.35 per cent.

In March 2014, we redeemed all four million Series Y preferred shares of TCPL at a price of \$50 per share plus \$0.2455 representing accrued and unpaid dividends. The total face value of the outstanding Series Y Shares was \$200 million and carried an aggregate of \$11 million in annualized dividends.

The net proceeds of the above debt and preferred share offerings were used for general corporate purposes and to reduce short-term indebtedness.

TC PIPELINES, LP AT-THE-MARKET (ATM) EQUITY ISSUANCE PROGRAM

Beginning in August 2014, TC PipeLines, LP began its at-the-market equity issuance program (ATM Program). TC PipeLines, LP may offer and sell common units having an aggregate offering price of up to US\$200 million. Net proceeds from sales under the program will be used for general partnership purposes, which may include debt repayment and future acquisitions.

From August until September 30, 2014, 1.3 million common units were issued under the ATM program generating net proceeds of approximately US\$73 million. Our ownership interest in TC PipeLines, LP will decrease as a result of the ATM program. The issuance did not significantly impact our income in third quarter 2014.

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DIVIDENDS

On November 3, 2014, we declared quarterly dividends as follows:

Quarterly dividend on our common shares

\$0.48 per share

Payable on January 30, 2015 to shareholders of record at the close of business on December 31, 2014

Quarterly dividends on our preferred shares

Series 1 \$0.2875

Series 3 \$0.25

Payable on December 31, 2014 to shareholders of record at the close of business on December 1, 2014

Series 5 \$0.275

Series 7 \$0.25

Series 9 \$0.265625

Payable on January 30, 2015 to shareholders of record at the close of business on December 31, 2014

SHARE INFORMATION**October 30, 2014**

Common shares		Issued and outstanding	
		709 million	
Preferred shares		Issued and outstanding	Convertible to
Series 1		22 million	22 million Series 2 preferred shares
Series 3		14 million	14 million Series 4 preferred shares
Series 5		14 million	14 million Series 6 preferred shares
Series 7		24 million	24 million Series 8 preferred shares
Series 9		18 million	18 million Series 10 preferred shares
Options to buy common shares		Outstanding	Exercisable
		9 million	5 million

CREDIT FACILITIES

We use committed revolving credit facilities to support our commercial paper programs and, along with demand facilities, for general corporate purposes including issuing letters of credit as well as providing additional liquidity.

At September 30, 2014, we had \$6.5 billion in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	Description and Use	Matures
\$3.0 billion	\$3.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	December 2018
US\$1.0 billion	US\$1.0 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes	November 2014
US\$1.0 billion	US\$1.0 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports the TAIL U.S. commercial paper program	November 2014
\$1.3 billion	\$0.3 billion	TCPL, TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At September 30, 2014, we had \$1.0 billion outstanding in letters of credit under these lines	Demand

See Financial risks and financial instruments for more information about liquidity, market and other risks.

CONTRACTUAL OBLIGATIONS

Our capital commitments have decreased by approximately \$400 million since December 31, 2013 primarily due to the completion or advancement of capital projects. Our other purchase obligations have decreased by approximately \$500 million since December 31, 2013 primarily due to re-contracting for natural gas storage services in Alberta for a shorter period and a reduced average volume. There were no other material changes to our contractual obligations in third quarter 2014 or to payments due in the next five years or after. See the MD&A in our 2013 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to liquidity risk, counterparty credit risk and market risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value. These are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

See our 2013 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2013.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash requirements for a rolling twelve month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

COUNTERPARTY CREDIT RISK

We have exposure to counterparty credit risk in the following areas:

- accounts receivable
- the fair value of derivative assets
- notes receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At September 30, 2014 we had not incurred any significant credit losses and had no significant amounts past due or impaired. We had a credit risk concentration of \$224 million with one counterparty at September 30, 2014 (December 31, 2013 - \$240 million). This amount is secured by a guarantee from the counterparty's parent company and we anticipate collecting the full amount.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

FOREIGN EXCHANGE AND INTEREST RATE RISK

Certain of our businesses generate income in U.S. dollars, but since we report in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, our exposure to changes in currency exchange rates increases. Some of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk. We manage this using a combination of interest rate swaps and options.

Average exchange rate - U.S. to Canadian dollars

third quarter 2014	1.09
third quarter 2013	1.03

The impact of changes in the value of the U.S. dollar on our U.S. dollar-denominated operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below.

Significant U.S. dollar-denominated amounts

(unaudited - millions of US\$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
U.S. and International Natural Gas Pipelines comparable EBIT	118	111	469	412
U.S. Liquids Pipelines comparable EBIT	155	98	417	287
U.S. Power comparable EBIT	91	82	211	178
Interest expense on U.S. dollar-denominated long-term debt	(215)	(188)	(638)	(561)
Capitalized interest on U.S. capital expenditures	30	59	125	152
U.S. non-controlling interests and other	(52)	(49)	(184)	(136)
	127	113	400	332

NET INVESTMENT IN FOREIGN OPERATIONS

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options. The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

(unaudited - millions of \$)	September 30, 2014		December 31, 2013	
	Fair value ¹	Notional or principal amount	Fair value ¹	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency swaps (maturing 2014 to 2019) ²	(342)	US 3,050	(201)	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2014)	(8)	US 450	(11)	US 850
	(350)	US 3,500	(212)	US 4,650

1 Fair values equal carrying values.

2 Net income in the three and nine months ended September 30, 2014 included net realized gains of \$5 million and \$16 million, respectively, (2013 - gains of \$8 million and \$22 million, respectively) related to the interest component of cross-currency swaps.

U.S. dollar-denominated debt designated as a net investment hedge

(unaudited - millions of \$)	September 30, 2014	December 31, 2013
Carrying value	16,400 (US 14,600)	14,200 (US 13,400)
Fair value	18,700 (US 16,700)	16,000 (US 15,000)

The balance sheet classification of the fair value of derivatives used to hedge our net investment in foreign operations is as follows:

(unaudited - millions of \$)	September 30, 2014	December 31, 2013
Other current assets	5	5
Intangible and other assets	1	—
Accounts payable and other	(110)	(50)
Other long-term liabilities	(246)	(167)
	(350)	(212)

FINANCIAL INSTRUMENTS

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in

accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of long-term debt has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify. The effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in OCI in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

Derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair value of held for trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses current market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives have been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments is as follows:

(unaudited - millions of \$)	September 30, 2014	December 31, 2013
Other current assets	463	395
Intangible and other assets	144	112
Accounts payable and other	(495)	(357)
Other long-term liabilities	(339)	(255)
	(227)	(105)

THIRD QUARTER 2014

The effect of derivative instruments on the consolidated statement of income

The following summary does not include hedges of our net investment in foreign operations.

(unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Derivative instruments held for trading¹				
Amount of unrealized gains/(losses) in the period				
Power	20	18	35	15
Natural gas	7	13	(14)	1
Foreign exchange	(32)	16	(9)	(1)
Amount of realized gains/(losses) in the period				
Power	8	(10)	(23)	(46)
Natural gas	(27)	(14)	19	(21)
Foreign exchange	(1)	3	(19)	(5)
Derivative instruments in hedging relationships^{2,3}				
Amount of realized (losses)/gains in the period				
Power	(50)	(18)	138	(29)
Natural gas	—	—	—	(1)
Interest	1	1	3	5

- 1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held for trading derivative instruments are included net in interest expense and interest income and other, respectively.
- 2 At September 30, 2014, all hedging relationships were designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of \$3 million (2013 - \$7 million) and a notional amount of US\$400 million (2013 - US\$200 million). For the three and nine months ended September 30, 2014, net realized gains on fair value hedges were \$2 million and \$5 million, respectively (2013 - \$1 million and \$5 million, respectively) and were included in interest expense. For the three and nine months ended September 30, 2014 and 2013, we did not record any amounts in net income related to ineffectiveness for fair value hedges.
- 3 The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles. For the three and nine months ended September 30, 2014 and 2013, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of the Condensed consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

(unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Change in fair value of derivative instruments recognized in OCI (effective portion)				
Power	62	28	96	(6)
Natural gas	(1)	(1)	(2)	(1)
Foreign exchange	—	1	10	5
Interest	1	(1)	—	(1)
	62	27	104	(3)
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion) ¹				
Power	—	33	(109)	34
Natural gas	1	1	3	3
Interest	4	4	12	12
	5	38	(94)	49
Gains/(losses) on derivative instruments recognized in earnings (ineffective portion)				
Power	23	6	13	(1)
	23	6	13	(1)

- 1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

Credit risk related contingent features of derivative instruments

Derivatives contracts often contain financial assurance provisions that may require us to provide collateral if a credit risk related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade).

Based on contracts in place and market prices at September 30, 2014, the aggregate fair value of all derivative contracts with credit risk related contingent features that were in a net liability position was \$13 million (December 31, 2013 - \$16 million), with collateral provided in the normal course of business of nil (December 31, 2013 – nil). If the credit risk related contingent features in these agreements had been triggered on September 30, 2014, we would have been required to provide collateral of \$13 million (December 31, 2013 - \$16 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

We feel we have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2014, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in third quarter 2014 that had or are likely to have a material impact on our internal control over financial reporting, other than noted below.

Effective January 1, 2014, management implemented an ERP system. As a result of the ERP system, certain processes supporting our internal control over financial reporting have changed. Management will continue to monitor the effectiveness of these processes going forward.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. You can find a summary of our critical accounting estimates in our 2013 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2013 other than described below. You can find a summary of our significant accounting policies in our 2013 Annual Report.

Changes in accounting policies for 2014

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This new guidance was effective January 1, 2014. There was no material impact on our consolidated financial statements as a result of applying this new standard.

Foreign currency matters - cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This new guidance was effective prospectively from January 1, 2014 and will be applied for all applicable transactions after that date.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This new guidance was effective January 1, 2014. There was no material impact on our consolidated financial statements as a result of applying this new standard.

Future accounting changes**Reporting discontinued operations**

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance is effective from January 1, 2015 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

Revenue from contracts with customers

In May 2014, the FASB issued new guidance on Revenue from Contracts with Customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This new guidance is effective from January 1, 2017 with two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. Early application is not permitted. We are currently evaluating the impact of the adoption of this ASU and have not yet determined the effect on our consolidated financial statements.

Reconciliation of non-GAAP measures

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
EBITDA	1,435	1,294	4,099	3,638
Cancarb gain on sale	—	—	(108)	—
Niska contract termination	2	—	43	—
NEB decision - 2012	—	—	—	(55)
Non-comparable risk management activities affecting EBITDA	(50)	(37)	(34)	(15)
Comparable EBITDA	1,387	1,257	4,000	3,568
Comparable depreciation and amortization	(403)	(366)	(1,195)	(1,076)
Comparable EBIT	984	891	2,805	2,492
Other income statement items				
Comparable interest expense	(304)	(235)	(875)	(744)
Comparable interest income and other	49	16	72	32
Comparable income tax expense	(230)	(172)	(616)	(464)
Net income attributable to non-controlling interests	(25)	(33)	(110)	(87)
Preferred share dividends	(24)	(20)	(72)	(55)
Comparable earnings	450	447	1,204	1,174
Specific items (net of tax):				
Cancarb gain on sale	—	—	99	—
Niska contract termination	(1)	—	(32)	—
NEB decision - 2012	—	—	—	84
Part VI.I income tax adjustment	—	—	—	25
Risk management activities ¹	8	34	14	9
Net income attributable to common shares	457	481	1,285	1,292
Comparable depreciation and amortization	(403)	(366)	(1,195)	(1,076)
Specific item:				
NEB decision - 2012	—	—	—	(13)
Depreciation and amortization	(403)	(366)	(1,195)	(1,089)
Comparable interest expense	(304)	(235)	(875)	(744)
Specific item:				
NEB decision - 2012	—	—	—	(1)
Interest expense	(304)	(235)	(875)	(745)
Comparable interest income and other	49	16	72	32
Specific items:				
NEB decision - 2012	—	—	—	1
Risk management activities ¹	(32)	15	(9)	—
Interest income and other	17	31	63	33
Comparable income tax expense	(230)	(172)	(616)	(464)
Specific items:				
Cancarb gain on sale	—	—	(9)	—
Niska contract termination	1	—	11	—
NEB decision - 2012	—	—	—	42
Part VI.I income tax adjustment	—	—	—	25
Risk management activities ¹	(10)	(18)	(11)	(6)
Income tax expense	(239)	(190)	(625)	(403)

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Comparable earnings per common share	\$0.63	\$0.63	\$1.70	\$1.66
Specific items (net of tax):				
Cancarb gain on sale	—	—	0.14	—
Niska contract termination	—	—	(0.04)	—
NEB decision - 2012	—	—	—	0.12
Part VI.I income tax adjustment	—	—	—	0.04
Risk management activities ¹	0.01	0.05	0.01	0.01
Net income per common share	\$0.64	\$0.68	\$1.81	\$1.83

1 Risk management activities (unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Canadian Power	2	4	—	(2)
U.S. Power	41	31	30	14
Natural Gas Storage	7	2	4	3
Foreign exchange	(32)	15	(9)	—
Income tax attributable to risk management activities	(10)	(18)	(11)	(6)
Total gains from risk management activities	8	34	14	9

Comparable EBITDA and EBIT by business segment

three months ended September 30, 2014 (unaudited - millions of \$)	Natural Gas Pipelines	Liquids Pipelines ¹	Energy	Corporate	Total
EBITDA	750	281	435	(31)	1,435
Niska contract termination	—	—	2	—	2
Non-comparable risk management activities affecting EBITDA	—	—	(50)	—	(50)
Comparable EBITDA	750	281	387	(31)	1,387
Comparable depreciation and amortization	(266)	(55)	(76)	(6)	(403)
Comparable EBIT	484	226	311	(37)	984

three months ended September 30, 2013 (unaudited - millions of \$)	Natural Gas Pipelines	Liquids Pipelines ¹	Energy	Corporate	Total
EBITDA	684	189	447	(26)	1,294
Non-comparable risk management activities affecting EBITDA	—	—	(37)	—	(37)
Comparable EBITDA	684	189	410	(26)	1,257
Comparable depreciation and amortization	(248)	(37)	(77)	(4)	(366)
Comparable EBIT	436	152	333	(30)	891

THIRD QUARTER 2014

nine months ended September 30, 2014 (unaudited - millions of \$)	Natural Gas Pipelines	Liquids Pipelines¹	Energy	Corporate	Total
EBITDA	2,357	771	1,062	(91)	4,099
Cancarb gain on sale	—	—	(108)	—	(108)
Niska contract termination	—	—	43	—	43
Non-comparable risk management activities affecting EBITDA	—	—	(34)	—	(34)
Comparable EBITDA	2,357	771	963	(91)	4,000
Comparable depreciation and amortization	(791)	(158)	(230)	(16)	(1,195)
Comparable EBIT	1,566	613	733	(107)	2,805

nine months ended September 30, 2013 (unaudited - millions of \$)	Natural Gas Pipelines	Liquids Pipelines¹	Energy	Corporate	Total
EBITDA	2,129	554	1,032	(77)	3,638
NEB decision - 2012	(55)	—	—	—	(55)
Non-comparable risk management activities affecting EBITDA	—	—	(15)	—	(15)
Comparable EBITDA	2,074	554	1,017	(77)	3,568
Comparable depreciation and amortization	(733)	(111)	(220)	(12)	(1,076)
Comparable EBIT	1,341	443	797	(89)	2,492

1 Previously Oil Pipelines.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of \$, except per share amounts)	2014				2013			2012
	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	2,451	2,234	2,884	2,332	2,204	2,009	2,252	2,089
Net income attributable to common shares	457	416	412	420	481	365	446	306
Comparable earnings	450	332	422	410	447	357	370	318
Share statistics								
Net income per common share - basic and diluted	\$0.64	\$0.59	\$0.58	\$0.59	\$0.68	\$0.52	\$0.63	\$0.43
Comparable earnings per share	\$0.63	\$0.47	\$0.60	\$0.58	\$0.63	\$0.51	\$0.52	\$0.45
Dividends declared per common share	\$0.48	\$0.48	\$0.48	\$0.46	\$0.46	\$0.46	\$0.46	\$0.44

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income sometimes fluctuate. The causes of these fluctuations vary across our business segments.

In Natural Gas Pipelines, quarter-over-quarter revenues and net income from the Canadian regulated pipelines generally remain relatively stable during any fiscal year. Our U.S. natural gas pipelines are generally seasonal in nature with higher earnings in the winter months as a result of increased customer demands. Over the long term, however, results from both our Canadian and U.S. natural gas pipelines fluctuate because of:

- regulatory decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Liquids Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are affected by:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

In Energy, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- market prices
- capacity prices and payments
- planned and unplanned plant outages
- acquisitions and divestitures
- certain fair value adjustments
- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate 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.

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

THIRD QUARTER 2014

In second quarter 2014, comparable earnings excluded a \$99 million after-tax gain on the sale of Cancarb Limited and a \$31 million after-tax loss related to the termination of the Niska Gas Storage contract.

In second quarter 2013, comparable earnings excluded a \$25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

In first quarter 2013, comparable earnings excluded \$84 million of net income in 2013 related to 2012 from the NEB decision (RH-003-2011).

Condensed consolidated statement of income

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian \$, except per share amounts)	2014	2013	2014	2013
Revenues				
Natural gas pipelines	1,145	1,083	3,514	3,271
Liquids pipelines	387	281	1,112	830
Energy	919	840	2,943	2,364
	2,451	2,204	7,569	6,465
Income from Equity Investments	159	177	362	423
Operating and Other Expenses				
Plant operating costs and other	674	650	2,163	1,939
Commodity purchases resold	388	299	1,422	958
Property taxes	113	138	355	353
Depreciation and amortization	403	366	1,195	1,089
Gain on sale of assets	—	—	(108)	—
	1,578	1,453	5,027	4,339
Financial Charges/(Income)				
Interest expense	304	235	875	745
Interest income and other	(17)	(31)	(63)	(33)
	287	204	812	712
Income before Income Taxes	745	724	2,092	1,837
Income Tax Expense				
Current	22	(3)	104	40
Deferred	217	193	521	363
	239	190	625	403
Net Income	506	534	1,467	1,434
Net income attributable to non-controlling interests	25	33	110	87
Net Income Attributable to Controlling Interests	481	501	1,357	1,347
Preferred share dividends	24	20	72	55
Net Income Attributable to Common Shares	457	481	1,285	1,292
Net Income per Common Share				
Basic and diluted	\$0.64	\$0.68	\$1.81	\$1.83
Dividends Declared per Common Share	\$0.48	\$0.46	\$1.44	\$1.38
Weighted Average Number of Common Shares (millions)				
Basic	708	707	708	707
Diluted	710	708	709	708

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Net Income	506	534	1,467	1,434
Other Comprehensive Income, Net of Income Taxes				
Foreign currency translation gains and losses on net investment in foreign operations	287	(140)	337	196
Change in fair value of net investment hedges	(121)	62	(169)	(122)
Change in fair value of cash flow hedges	37	14	64	(9)
Reclassification to Net Income of gains and losses on cash flow hedges	5	27	(55)	34
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	—	1	—	1
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	5	5	14	17
Other comprehensive income/(loss) on equity investments	—	(1)	2	(4)
Other comprehensive income/(loss) (Note 8)	213	(32)	193	113
Comprehensive Income	719	502	1,660	1,547
Comprehensive income attributable to non-controlling interests	97	5	187	116
Comprehensive Income Attributable to Controlling Interests	622	497	1,473	1,431
Preferred share dividends	24	20	72	55
Comprehensive Income Attributable to Common Shares	598	477	1,401	1,376

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian \$)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Cash Generated from Operations				
Net income	506	534	1,467	1,434
Depreciation and amortization	403	366	1,195	1,089
Deferred income taxes	217	193	521	363
Income from equity investments	(159)	(177)	(362)	(423)
Distributed earnings received from equity investments	161	163	415	427
Employee post-retirement benefits funding lower than expense	16	7	28	33
Gain on sale of assets	—	—	(108)	—
Other	(73)	(40)	(66)	(6)
Decrease/(increase) in operating working capital	171	72	250	(252)
Net cash provided by operations	1,242	1,118	3,340	2,665
Investing Activities				
Capital expenditures	(853)	(992)	(2,598)	(3,030)
Equity investments	(66)	(30)	(195)	(101)
Acquisitions	(181)	(99)	(181)	(154)
Proceeds from sale of assets, net of transaction costs	—	—	187	—
Deferred amounts and other	(31)	(103)	(148)	(267)
Net cash used in investing activities	(1,131)	(1,224)	(2,935)	(3,552)
Financing Activities				
Dividends on common and preferred shares	(364)	(346)	(1,074)	(1,012)
Distributions paid to non-controlling interests	(42)	(44)	(134)	(114)
Notes payable issued/(repaid), net	377	(1,177)	(145)	(618)
Long-term debt issued, net of issue costs	—	2,173	1,380	2,917
Repayment of long-term debt	(38)	(521)	(1,020)	(1,230)
Common shares issued, net of issue costs	27	4	43	59
Partnership units of subsidiary issued, net of issue costs	79	—	79	384
Preferred shares issued, net of issue costs	—	—	440	585
Preferred shares of subsidiary redeemed	—	—	(200)	—
Net cash provided by/(used in) financing activities	39	89	(631)	971
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents				
	(19)	(12)	(3)	10
Increase/(decrease) in Cash and Cash Equivalents	131	(29)	(229)	94
Cash and Cash Equivalents				
Beginning of period	567	674	927	551
Cash and Cash Equivalents				
End of period	698	645	698	645

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian \$)		September 30, 2014	December 31, 2013
ASSETS			
Current Assets			
Cash and cash equivalents		698	927
Accounts receivable		1,288	1,122
Inventories		267	251
Other		1,102	847
		3,355	3,147
Plant, Property and Equipment,	net of accumulated depreciation of \$19,097 and \$17,851, respectively	40,189	37,606
Equity Investments		5,789	5,759
Regulatory Assets		1,569	1,735
Goodwill		3,897	3,696
Intangible and Other Assets		2,357	1,955
		57,156	53,898
LIABILITIES			
Current Liabilities			
Notes payable		1,749	1,842
Accounts payable and other		2,705	2,155
Accrued interest		381	388
Current portion of long-term debt		1,742	973
		6,577	5,358
Regulatory Liabilities		218	229
Other Long-Term Liabilities		775	656
Deferred Income Tax Liabilities		5,141	4,564
Long-Term Debt		22,391	21,892
Junior Subordinated Notes		1,120	1,063
		36,222	33,762
EQUITY			
Common shares, no par value		12,197	12,149
Issued and outstanding:	September 30, 2014 - 709 million shares December 31, 2013 - 707 million shares		
Preferred shares		2,255	1,813
Additional paid-in capital		405	401
Retained earnings		5,360	5,096
Accumulated other comprehensive loss (Note 8)		(818)	(934)
Controlling Interests		19,399	18,525
Non-controlling interests		1,535	1,611
		20,934	20,136
		57,156	53,898
Contingencies and Guarantees (Note 11)			
Subsequent Event (Note 12)			

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

(unaudited - millions of Canadian \$)	nine months ended September 30	
	2014	2013
Common Shares		
Balance at beginning of period	12,149	12,069
Shares issued on exercise of stock options	48	67
Balance at end of period	12,197	12,136
Preferred Shares		
Balance at beginning of period	1,813	1,224
Shares issued under public offering, net of issue costs	442	589
Balance at end of period	2,255	1,813
Additional Paid-In Capital		
Balance at beginning of period	401	379
Issuance of stock options, net of exercises	1	(2)
Dilution impact from TC PipeLines, LP units issued	9	29
Redemption of subsidiary's preferred shares	(6)	—
Balance at end of period	405	406
Retained Earnings		
Balance at beginning of period	5,096	4,687
Net income attributable to controlling interests	1,357	1,347
Common share dividends	(1,019)	(976)
Preferred share dividends	(74)	(57)
Balance at end of period	5,360	5,001
Accumulated Other Comprehensive Loss		
Balance at beginning of period	(934)	(1,448)
Other comprehensive income	116	84
Balance at end of period	(818)	(1,364)
Equity Attributable to Controlling Interests	19,399	17,992
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	1,611	1,425
Net income attributable to non-controlling interests		
TC PipeLines, LP	98	63
Preferred share dividends of TCPL	2	17
Portland	10	7
Other comprehensive income attributable to non-controlling interests	77	29
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	79	384
Decrease in TransCanada's ownership	(14)	(47)
Distributions to non-controlling interests	(134)	(114)
Redemption of subsidiary's preferred shares	(194)	—
Foreign exchange and other	—	7
Balance at end of period	1,535	1,771
Total Equity	20,934	19,763

See accompanying notes to the condensed consolidated financial statements.

Notes to condensed consolidated financial statements (unaudited)

1. Basis of presentation

These condensed consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TransCanada's annual audited consolidated financial statements for the year ended December 31, 2013. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TransCanada's 2013 Annual Report.

These condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2013 audited consolidated financial statements included in TransCanada's 2013 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's Natural Gas Pipelines segment due to the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Energy segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

USE OF ESTIMATES AND JUDGEMENTS

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the consolidated financial statements for the year ended December 31, 2013, except as described in Note 2, Changes in accounting policies.

2. Changes in accounting policies

CHANGES IN ACCOUNTING POLICIES FOR 2014

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This new guidance was effective January 1, 2014. There was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Foreign currency matters - cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This new guidance was effective prospectively from January 1, 2014 and will be applied for all applicable transactions after that date.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This new guidance was effective January 1, 2014. There was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

FUTURE ACCOUNTING CHANGES

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance is effective from January 1, 2015 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Revenue from contracts with customers

In May 2014, the FASB issued new guidance on Revenue from Contracts with Customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This new guidance is effective from January 1, 2017 with two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. Early application is not permitted. The Company is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its consolidated financial statements.

3. Segmented information

three months ended September 30 (unaudited - millions of Canadian \$)	Natural Gas Pipelines		Liquids Pipelines ¹		Energy		Corporate		Total	
	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
Revenues	1,145	1,083	387	281	919	840	—	—	2,451	2,204
Income from equity investments	35	36	—	—	124	141	—	—	159	177
Plant operating costs and other	(349)	(326)	(92)	(81)	(202)	(217)	(31)	(26)	(674)	(650)
Commodity purchases resold	—	—	—	—	(388)	(299)	—	—	(388)	(299)
Property taxes	(81)	(109)	(14)	(11)	(18)	(18)	—	—	(113)	(138)
Depreciation and amortization	(266)	(248)	(55)	(37)	(76)	(77)	(6)	(4)	(403)	(366)
Segmented earnings	484	436	226	152	359	370	(37)	(30)	1,032	928
Interest expense									(304)	(235)
Interest income and other									17	31
Income before income taxes									745	724
Income tax expense									(239)	(190)
Net income									506	534
Net income attributable to non-controlling interests									(25)	(33)
Net income attributable to controlling interests									481	501
Preferred share dividends									(24)	(20)
Net income attributable to common shares									457	481

1 Previously Oil Pipelines.

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nine months ended September 30 (unaudited - millions of Canadian \$)	Natural Gas Pipelines		Liquids Pipelines ¹		Energy		Corporate		Total	
	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
Revenues	3,514	3,271	1,112	830	2,943	2,364	—	—	7,569	6,465
Income from equity investments	124	105	—	—	238	318	—	—	362	423
Plant operating costs and other	(1,030)	(983)	(293)	(242)	(749)	(637)	(91)	(77)	(2,163)	(1,939)
Commodity purchases resold	—	—	—	—	(1,422)	(958)	—	—	(1,422)	(958)
Property taxes	(251)	(264)	(48)	(34)	(56)	(55)	—	—	(355)	(353)
Depreciation and amortization	(791)	(746)	(158)	(111)	(230)	(220)	(16)	(12)	(1,195)	(1,089)
Gain on sale of assets	—	—	—	—	108	—	—	—	108	—
Segmented earnings	1,566	1,383	613	443	832	812	(107)	(89)	2,904	2,549
Interest expense									(875)	(745)
Interest income and other									63	33
Income before income taxes									2,092	1,837
Income tax expense									(625)	(403)
Net income									1,467	1,434
Net income attributable to non-controlling interests									(110)	(87)
Net income attributable to controlling interests									1,357	1,347
Preferred share dividends									(72)	(55)
Net income attributable to common shares									1,285	1,292

1 Previously Oil Pipelines.

TOTAL ASSETS

(unaudited - millions of Canadian \$)	September 30, 2014	December 31, 2013
Natural Gas Pipelines	26,273	25,165
Liquids Pipelines ¹	15,266	13,253
Energy	13,939	13,747
Corporate	1,678	1,733
	57,156	53,898

1 Previously Oil Pipelines.

4. Acquisitions and disposition

In September 2014, TransCanada acquired three additional Ontario solar power facilities from Canadian Solar Solutions Inc. for \$181 million net of working capital adjustments. TransCanada measured the assets and liabilities acquired at fair value with substantially all of the purchase price allocated to Plant, Property and Equipment and no Goodwill was recorded.

On April 15, 2014, TransCanada sold Cancarb Limited and its related power generation for aggregate gross proceeds of \$190 million. TransCanada recognized a gain on the sale of \$108 million (\$99 million after tax) which has been presented separately on the consolidated statement of income.

5. Income taxes

At September 30, 2014, the total unrecognized tax benefit of uncertain tax positions was approximately \$20 million (December 31, 2013 - \$23 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the three and nine months ended September 30, 2014 is nil of interest expense and nil for penalties (September 30, 2013 - nil of interest expense and nil for penalties). At September 30, 2014, the Company had \$6 million accrued for interest expense and nil accrued for penalties (December 31, 2013 - \$6 million accrued for interest expense and nil for penalties).

The effective tax rates for the nine-month periods ended September 30, 2014 and 2013 were 30 per cent and 22 per cent, respectively. The higher effective tax rate in 2014 compared to 2013 was primarily the result of the impact of the 2013 NEB decision (RH-003-2011), changes in the proportion of income earned between Canadian and foreign jurisdictions as well as higher flow-through taxes in 2014 on Canadian regulated pipelines, partially offset by the disposition of Cancarb Limited in 2014.

6. Long-term debt

In the three and nine months ended September 30, 2014, TransCanada capitalized interest related to capital projects of \$57 million and \$199 million, respectively (2013 - \$80 million and \$195 million, respectively).

LONG-TERM DEBT ISSUED

Amount (unaudited - millions of \$)	Type	Maturity date	Interest rate	Date issued
US\$1,250	Senior unsecured notes	March 1, 2034	4.625%	February 2014

LONG-TERM DEBT RETIRED

Amount (unaudited - millions of Canadian \$)	Type	Retirement date	Interest rate
\$450	Medium term notes	January 2014	5.65%
\$300	Medium term notes	February 2014	5.05%
\$125	Debenture	June 2014	11.10%
\$53	Debenture	June 2014	11.20%

7. Equity and share capital

PREFERRED SHARE ISSUANCE

In January 2014, TransCanada completed a public offering of 18 million Series 9 cumulative redeemable first preferred shares at \$25 per share resulting in gross proceeds of \$450 million. The holders of the Series 9 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of \$1.0625 per share, payable quarterly. The dividend rate will reset on October 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 2.35 per cent. The preferred shares are redeemable by TransCanada on or after October 30, 2019 and on October 30 of every fifth year thereafter at a price of \$25 per share plus accrued and unpaid dividends.

The Series 9 preferred shareholders will have the right to convert their shares into Series 10 cumulative redeemable first preferred shares on October 30, 2019 and on October 30 of every fifth year thereafter. The holders of Series 10 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 2.35 per cent.

PREFERRED SHARE REDEMPTION

On March 5, 2014, TCPL redeemed all of the four million outstanding 5.60 per cent cumulative redeemable first preferred shares Series Y at a price of \$50 per share plus \$0.2455 representing accrued and unpaid dividends to the redemption date.

8. Other comprehensive income/(loss) and accumulated other comprehensive loss

Components of other comprehensive income/(loss) including non-controlling interests and the related tax effects are as follows:

three months ended September 30, 2014 (unaudited - millions of Canadian \$)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains and losses on net investment in foreign operations	234	53	287
Change in fair value of net investment hedges	(164)	43	(121)
Change in fair value of cash flow hedges	62	(25)	37
Reclassification to net income of gains and losses on cash flow hedges	5	—	5
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	6	(1)	5
Other comprehensive income/(loss) on equity investments	2	(2)	—
Other comprehensive income	145	68	213

three months ended September 30, 2013 (unaudited - millions of Canadian \$)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains and losses on net investment in foreign operations	(104)	(36)	(140)
Change in fair value of net investment hedges	83	(21)	62
Change in fair value of cash flow hedges	27	(13)	14
Reclassification to net income of gains and losses on cash flow hedges	38	(11)	27
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	2	(1)	1
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	9	(4)	5
Other comprehensive loss on equity investments	(1)	—	(1)
Other comprehensive income/(loss)	54	(86)	(32)

nine months ended September 30, 2014 (unaudited - millions of Canadian \$)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains and losses on net investment in foreign operations	285	52	337
Change in fair value of net investment hedges	(228)	59	(169)
Change in fair value of cash flow hedges	104	(40)	64
Reclassification to net income of gains and losses on cash flow hedges	(94)	39	(55)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	19	(5)	14
Other comprehensive income/(loss) on equity investments	3	(1)	2
Other comprehensive income	89	104	193

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nine months ended September 30, 2013 (unaudited - millions of Canadian \$)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains and losses on net investment in foreign operations	144	52	196
Change in fair value of net investment hedges	(165)	43	(122)
Change in fair value of cash flow hedges	(3)	(6)	(9)
Reclassification to net income of gains and losses on cash flow hedges	49	(15)	34
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	2	(1)	1
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	26	(9)	17
Other comprehensive (loss)/income on equity investments	(5)	1	(4)
Other comprehensive income	48	65	113

The changes in accumulated other comprehensive loss by component are as follows:

three months ended September 30, 2014 (unaudited - millions of Canadian \$)	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity Investments	Total¹
AOCI balance at July 1, 2014	(632)	(37)	(188)	(102)	(959)
Other comprehensive income before reclassifications ²	94	37	—	—	131
Amounts reclassified from accumulated other comprehensive loss ³	—	5	5	—	10
Net current period other comprehensive income	94	42	5	—	141
AOCI balance at September 30, 2014	(538)	5	(183)	(102)	(818)

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest gains of \$72 million.

3 Gains related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be \$65 million (\$39 million, net of tax) at September 30, 2014. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

nine months ended September 30, 2014 (unaudited - millions of Canadian \$)	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity Investments	Total¹
AOCI balance at January 1, 2014	(629)	(4)	(197)	(104)	(934)
Other comprehensive income before reclassifications ²	91	64	—	—	155
Amounts reclassified from accumulated other comprehensive loss ³	—	(55)	14	2	(39)
Net current period other comprehensive income	91	9	14	2	116
AOCI balance at September 30, 2014	(538)	5	(183)	(102)	(818)

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest gains of \$77 million.

3 Gains related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be \$65 million (\$39 million, net of tax) at September 30, 2014. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of accumulated other comprehensive loss are as follows:

(unaudited - millions of Canadian \$)	Amounts reclassified from accumulated other comprehensive loss ¹		Affected line item in the condensed consolidated statement of income
	three months ended September 30, 2014	nine months ended September 30, 2014	
Cash flow hedges			
Power and natural gas	(1)	106	Revenue (Energy)
Interest	(4)	(12)	Interest expense
	(5)	94	Total before tax
	—	(39)	Income tax expense
	(5)	55	Net of tax
Pension and other post-retirement plan adjustments			
Amortization of actuarial loss and past service cost	(6)	(19)	²
	1	5	Income tax expense
	(5)	(14)	Net of tax
Equity Investments			
Equity income	(2)	(3)	Income from Equity Investments
	2	1	Income tax expense
	—	(2)	Net of tax

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.

2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 9 for additional detail.

9. Employee post-retirement benefits

The net benefit cost recognized for the Company's defined benefit pension plans and other post-retirement benefit plans is as follows:

(unaudited - millions of Canadian \$)	three months ended September 30				nine months ended September 30			
	Pension benefit plans		Other post- retirement benefit plans		Pension benefit plans		Other post- retirement benefit plans	
	2014	2013	2014	2013	2014	2013	2014	2013
Service cost	21	21	1	1	64	62	2	2
Interest cost	28	24	2	2	84	71	7	6
Expected return on plan assets	(35)	(31)	—	—	(104)	(89)	(1)	(1)
Amortization of actuarial loss	5	8	—	1	16	23	1	2
Amortization of past service cost	1	—	—	—	2	1	—	—
Amortization of regulatory asset	4	7	1	—	13	22	1	1
Amortization of transitional obligation related to regulated business	—	—	—	—	—	—	1	1
Net benefit cost recognized	24	29	4	4	75	90	11	11

10. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

TransCanada has exposure to counterparty credit risk and market risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings, cash flow and, ultimately, shareholder value.

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at

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fair value, the fair value of derivative assets and notes, and loans and advances receivable. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At September 30, 2014, there were no significant amounts past due or impaired, and there were no significant credit losses during the period.

At September 30, 2014, the Company had a credit risk concentration of \$224 million (December 31, 2013 - \$240 million) due from one counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

NET INVESTMENT IN FOREIGN OPERATIONS

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

U.S. dollar-denominated debt designated as a net investment hedge

(unaudited - millions of Canadian \$)	September 30, 2014	December 31, 2013
Carrying value	16,400 (US 14,600)	14,200 (US 13,400)
Fair value	18,700 (US 16,700)	16,000 (US 15,000)

Derivatives designated as a net investment hedge

(unaudited - millions of Canadian \$)	September 30, 2014		December 31, 2013	
	Fair Value ¹	Notional or principal amount	Fair value ¹	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency interest rate swaps (maturing 2014 to 2019) ²	(342)	US 3,050	(201)	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2014)	(8)	US 450	(11)	US 850
	(350)	US 3,500	(212)	US 4,650

1 Fair values equal carrying values.

2 Net income in the three and nine months ended September 30, 2014 included net realized gains of \$5 million and \$16 million, respectively, (2013 - gains of \$8 million and \$22 million, respectively) related to the interest component of cross-currency swaps which is included in interest expense.

Balance sheet presentation of net investment hedges

The balance sheet classification of the fair value of derivatives used to hedge the Company's net investment in foreign operations is as follows:

(unaudited - millions of Canadian \$)	September 30, 2014	December 31, 2013
Other current assets	5	5
Intangible and other assets	1	—
Accounts payable and other	(110)	(50)
Other long-term liabilities	(246)	(167)
	(350)	(212)

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of the Company's notes receivables is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of long-term debt is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity and would be classified in Level II of the fair value hierarchy.

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts equal fair value, and would be classified in Level II of the fair value hierarchy:

(unaudited - millions of Canadian \$)	September 30, 2014		December 31, 2013	
	Carrying amount ¹	Fair value	Carrying amount ¹	Fair value
Notes receivable and other ¹	203	249	226	269
Available for sale assets ²	60	60	47	47
Current and long-term debt ^{3,4}	(24,133)	(28,280)	(22,865)	(26,134)
Junior subordinated notes	(1,120)	(1,148)	(1,063)	(1,093)
	(24,990)	(29,119)	(23,655)	(26,911)

- Notes receivable are included in other current assets and intangible and other assets on the condensed consolidated balance sheet.
- Available for sale assets are included in intangible and other assets on the condensed consolidated balance sheet.
- Long-term debt is recorded at amortized cost, except for US\$400 million (December 31, 2013 - US\$200 million) that is attributed to hedged risk and recorded at fair value.
- Consolidated net income for the three and nine months ended September 30, 2014 included gains of \$2 million and losses of \$3 million, respectively, (2013 - losses of nil and \$7 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US\$400 million of long-term debt at September 30, 2014 (December 31, 2013 - US\$200 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Derivative instruments

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses current market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives and available for sale assets has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Where possible, derivative instruments are designated as hedges, but in some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments is as follows:

(unaudited - millions of Canadian \$)	September 30, 2014	December 31, 2013
Other current assets	463	395
Intangible and other assets	144	112
Accounts payable and other	(495)	(357)
Other long-term liabilities	(339)	(255)
	(227)	(105)

2014 derivative instruments summary

The following summary does not include hedges of the Company's net investment in foreign operations.

(unaudited - millions of Canadian \$ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading¹				
Fair values ^{2,3}				
Assets	\$392	\$46	\$1	\$5
Liabilities	(\$378)	(\$57)	(\$21)	(\$5)
Notional values ³				
Volumes ⁴				
Purchases	39,310	72	—	—
Sales	36,493	44	—	—
U.S. dollars	—	—	US 1,921	US 100
Net unrealized gains/(losses) in the period ⁵				
three months ended September 30, 2014	\$20	\$7	(\$32)	\$—
nine months ended September 30, 2014	\$35	(\$14)	(\$9)	\$—
Net realized gains/(losses) in the period ⁵				
three months ended September 30, 2014	\$8	(\$27)	(\$1)	\$—
nine months ended September 30, 2014	(\$23)	\$19	(\$19)	\$—
Maturity dates ³	2014-2018	2014-2020	2014-2015	2016
Derivative instruments in hedging relationships^{6,7}				
Fair values ^{2,3}				
Assets	\$154	\$—	\$—	\$3
Liabilities	(\$16)	\$—	\$—	(\$1)
Notional values ³				
Volumes ⁴				
Purchases	10,151	—	—	—
Sales	5,216	—	—	—
U.S. dollars	—	—	—	US 550
Net realized (losses)/gains in the period ⁵				
three months ended September 30, 2014	(\$50)	\$—	\$—	\$1
nine months ended September 30, 2014	\$138	\$—	\$—	\$3
Maturity dates ³	2014-2019	—	—	2015-2018

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

- 2 Fair values equal carrying values.

- 3 As at September 30, 2014.

- 4 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

- 5 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of the

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change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.

- 6 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of \$3 million and a notional amount of US\$400 million as at September 30, 2014. For the three and nine months ended September 30, 2014, net realized gains on fair value hedges were \$2 million and \$5 million, respectively, and were included in interest expense. For the three and nine months ended September 30, 2014, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.
- 7 For the three and nine months ended September 30, 2014, there were no gains or losses included in net income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

2013 derivative instruments summary

The following summary does not include hedges of the Company's net investment in foreign operations.

(unaudited - millions of Canadian \$ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading¹				
Fair values ^{2,3}				
Assets	\$265	\$73	\$—	\$8
Liabilities	(\$280)	(\$72)	(\$12)	(\$7)
Notional values ³				
Volumes ⁴				
Purchases	29,301	88	—	—
Sales	28,534	60	—	—
Canadian dollars	—	—	—	400
U.S. dollars	—	—	US 1,015	US 100
Net unrealized gains/(losses) in the period ⁵				
three months ended September 30, 2013	\$18	\$13	\$16	\$—
nine months ended September 30, 2013	\$15	\$1	(\$1)	\$—
Net realized (losses)/gains in the period ⁵				
three months ended September 30, 2013	(\$10)	(\$14)	\$3	\$—
nine months ended September 30, 2013	(\$46)	(\$21)	(\$5)	\$—
Maturity dates ³	2014-2017	2014-2016	2014	2014-2016
Derivative instruments in hedging relationships^{6,7}				
Fair values ^{2,3}				
Assets	\$150	\$—	\$—	\$6
Liabilities	(\$22)	\$—	(\$1)	(\$1)
Notional values ³				
Volumes ⁴				
Purchases	9,758	—	—	—
Sales	6,906	—	—	—
U.S. dollars	—	—	US 16	US 350
Net realized (losses)/gains in the period ⁵				
three months ended September 30, 2013	(\$18)	\$—	\$—	\$1
nine months ended September 30, 2013	(\$29)	(\$1)	\$—	\$5
Maturity dates ³	2014-2018	—	2014	2015-2018

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

2 Fair values equal carrying values.

3 As at December 31, 2013.

4 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

5 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.

6 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of \$5 million and a notional amount of US\$200 million as at December 31, 2013. Net realized gains on

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fair value hedges for the three and nine months ended September 30, 2013 were \$1 million and \$5 million, respectively, and were included in interest expense. For the three and nine months ended September 30, 2013, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

- 7 For the three and nine months ended September 30, 2013, there were no gains or losses included in net income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 8) related to derivatives in cash flow hedging relationships are as follows:

(unaudited - millions of Canadian \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Change in fair value of derivative instruments recognized in OCI (effective portion)				
Power	62	28	96	(6)
Natural gas	(1)	(1)	(2)	(1)
Foreign exchange	—	1	10	5
Interest	1	(1)	—	(1)
	62	27	104	(3)
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion) ¹				
Power	—	33	(109)	34
Natural gas	1	1	3	3
Interest	4	4	12	12
	5	38	(94)	49
Gains/(losses) on derivative instruments recognized in earnings (ineffective portion)				
Power	23	6	13	(1)
	23	6	13	(1)

- 1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TransCanada has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at September 30, 2014 (unaudited - millions of Canadian \$)			
	Gross derivative instruments presented on the balance sheet	Amounts available for offset ¹	Net amounts
Derivative - Asset			
Power	546	(356)	190
Natural gas	46	(45)	1
Foreign exchange	7	(7)	—
Interest	8	—	8
Total	607	(408)	199
Derivative - Liability			
Power	(394)	356	(38)
Natural gas	(57)	45	(12)
Foreign exchange	(377)	7	(370)
Interest	(6)	—	(6)
Total	(834)	408	(426)

- 1 Amounts available for offset do not include cash collateral pledged or received.

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With respect to all financial arrangements, including the derivative instruments presented above, as at September 30, 2014, the Company had provided cash collateral of \$102 million and letters of credit of \$33 million to its counterparties. The Company held \$8 million in cash collateral and \$6 million in letters of credit on asset exposures at September 30, 2014.

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2013:

at December 31, 2013 (unaudited - millions of Canadian \$)	Gross derivative instruments presented on the balance sheet	Amounts available for offset¹	Net amounts
Derivative - Asset			
Power	415	(277)	138
Natural gas	73	(61)	12
Foreign exchange	5	(5)	—
Interest	14	(2)	12
Total	507	(345)	162
Derivative - Liability			
Power	(302)	277	(25)
Natural gas	(72)	61	(11)
Foreign exchange	(230)	5	(225)
Interest	(8)	2	(6)
Total	(612)	345	(267)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to all financial arrangements, including the derivative instruments presented above as at December 31, 2013, the Company had provided cash collateral of \$67 million and letters of credit of \$85 million to its counterparties. The Company held \$11 million in cash collateral and \$32 million in letters of credit on asset exposures at December 31, 2013.

Credit risk related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit risk related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade.

Based on contracts in place and market prices at September 30, 2014, the aggregate fair value of all derivative instruments with credit risk related contingent features that were in a net liability position was \$13 million (December 31, 2013 - \$16 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2013 - nil). If the credit risk related contingent features in these agreements were triggered on September 30, 2014, the Company would have been required to provide collateral of \$13 million (December 31, 2013 - \$16 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company feels it has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

FAIR VALUE HIERARCHY

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.
Level II	<p>Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly.</p> <p>Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.</p> <p>This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and power and natural gas commodity derivatives where fair value is determined using the market approach.</p> <p>Transfers between Level I and Level II would occur when there is a change in market circumstances.</p>
Level III	<p>Valuation of assets and liabilities measured on a recurring basis using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. This category includes long-dated commodity transactions in certain markets where liquidity is low. Long-term electricity prices are estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which we operate.</p> <p>Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas is expected to or may result in a lower fair value measurement of contracts included in Level III.</p> <p>Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.</p>

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

at September 30, 2014 (unaudited - millions of Canadian \$, pre-tax)	Quoted prices in active markets (Level I) ¹	Significant other observable inputs (Level II) ¹	Significant unobservable inputs (Level III) ¹	Total
Derivative instrument assets:				
Power commodity contracts	—	543	3	546
Natural gas commodity contracts	21	23	2	46
Foreign exchange contracts	—	7	—	7
Interest rate contracts	—	8	—	8
Derivative instrument liabilities:				
Power commodity contracts	—	(391)	(3)	(394)
Natural gas commodity contracts	(35)	(20)	(2)	(57)
Foreign exchange contracts	—	(377)	—	(377)
Interest rate contracts	—	(6)	—	(6)
Non-derivative financial instruments:				
Available for sale assets	—	60	—	60
	(14)	(153)	—	(167)

1 There were no transfers from Level I to Level II or from Level II to Level III for the nine months ended September 30, 2014.

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The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2013, are categorized as follows:

at December 31, 2013 (unaudited - millions of Canadian \$, pre-tax)	Quoted prices in active markets (Level I) ¹	Significant other observable inputs (Level II) ¹	Significant unobservable inputs (Level III) ¹	Total
Derivative instrument assets:				
Power commodity contracts	—	411	4	415
Natural gas commodity contracts	48	25	—	73
Foreign exchange contracts	—	5	—	5
Interest rate contracts	—	14	—	14
Derivative instrument liabilities:				
Power commodity contracts	—	(299)	(3)	(302)
Natural gas commodity contracts	(50)	(22)	—	(72)
Foreign exchange contracts	—	(230)	—	(230)
Interest rate contracts	—	(8)	—	(8)
Non-derivative financial instruments:				
Available for sale assets	—	47	—	47
	(2)	(57)	1	(58)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2013.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

(unaudited - millions of Canadian \$, pre-tax)	Derivatives ¹			
	three months ended September 30		nine months ended September 30	
	2014	2013	2014	2013
Balance at beginning of period	(1)	—	1	(2)
Settlements	—	—	—	1
Transfers out of Level III	(1)	—	(1)	(1)
Total gains/(losses) included in net income	2	(1)	—	(1)
Total gains included in OCI	—	—	—	2
Balance at end of period	—	(1)	—	(1)

1 For the three and nine months ended September 30, 2014, Energy revenues include unrealized gains attributed to derivatives in the Level III category that were still held at the reporting date of \$2 million and nil, respectively (2013 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a \$2 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at September 30, 2014.

11. Contingencies and guarantees

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

GUARANTEES

TransCanada and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust (BPC), have each severally guaranteed certain contingent financial obligations of Bruce B related to a lease agreement and contractor and supplier services. In addition, TransCanada and BPC have each severally guaranteed one-half of certain

contingent financial obligations of Bruce A related to a sublease agreement and certain other financial obligations. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to delivery of natural gas, PPA payments and the payment of liabilities. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in other long-term liabilities. Information regarding the Company's guarantees is as follows:

(unaudited - millions of Canadian \$)	Term	at September 30, 2014		at December 31, 2013	
		Potential Exposure ¹	Carrying Value	Potential Exposure ¹	Carrying Value
Bruce Power	ranging to 2019 ²	639	7	740	8
Other jointly owned entities	ranging to 2040	60	10	51	10
		699	17	791	18

1 TransCanada's share of the potential estimated current or contingent exposure.

2 Except for one guarantee with no termination date.

12. Subsequent event

Bison Pipeline LLC

On October 1, 2014, TransCanada completed the sale of its remaining 30 per cent interest in Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US\$215 million.