U.S. Securities and Exchange Commission

Washington, D.C. 20549

Form 40-F

¨ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

x **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015 Commission File Number **1-31690**

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada

(Province or jurisdiction of incorporation or organization)

4922, 4923, 4924, 5172

(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable

(I.R.S. Employer Identification Number (if applicable))

TransCanada Tower, 450 - 1 Street S.W.
Calgary, Alberta, Canada, T2P 5H1
(403) 920-2000

(Address and telephone number of Registrant's principal executive offices)

TransCanada PipeLine USA Ltd., 700 Louisiana Street, Suite 700
Houston, Texas, 77002-2700; (832) 320-5201

(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Shares (including Rights under Shareholder Rights Plan)	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

For annual reports, indicate by check mark the information filed with this Form:

x Annual information form x Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

At December 31, 2015, 702,614,096 common shares;
9,498,423 Cumulative Redeemable First Preferred Shares, Series 1;
12,501,577 Cumulative Redeemable First Preferred Shares, Series 2;
8,533,405 Cumulative Redeemable First Preferred Shares, Series 3;
5,466,595 Cumulative Redeemable First Preferred Shares, Series 4;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5;
24,000,000 Cumulative Redeemable First Preferred Shares Series 7;
18,000,000 Cumulative Redeemable First Preferred Shares Series 9; and
10,000,000 Cumulative Redeemable First Preferred Shares, Series 11
were issued and outstanding.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes x No ¨

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended:

Form	Registration No.
S-8	333-5916
S-8	333-8470
S-8	333-9130
S-8	333-151736
S-8	333-184074
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929
F-10	333-208585

AUDITED CONSOLIDATED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders, except as otherwise specifically incorporated by reference in the TransCanada Corporation Annual information form, shall be deemed filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this report under the Exchange Act.

A. Audited Annual Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 119 through 183 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 7 through 118 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders included herein under the heading "Management's discussion and analysis".

C. Management's Report on Internal Control Over Financial Reporting

For management's report on internal control over financial reporting, see "Management's report on Internal Control over Financial Reporting" that accompanies the audited consolidated financial statements on page 119 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders included herein.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

For information on disclosure controls and procedures and management's annual report on internal control over financial reporting, see "Other information - Controls and Procedures" in Management's discussion and analysis on page 100 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's board of directors has determined that it has at least one audit committee financial expert serving on its audit committee. Mr. Siim A. Vanaselja, Mr. Kevin E. Benson and Mr. John E. Lowe have been designated audit committee financial experts and are independent, as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant. The Commission has indicated that the designation of Mr. Vanaselja, Mr. Benson and Mr. Lowe as audit committee financial experts does not make Mr. Vanaselja, Mr. Benson or Mr. Lowe "experts" for any purpose, impose any duties, obligations or liability on Mr. Vanaselja, Mr. Benson or Mr. Lowe that are greater than those imposed on members of the Audit committee and Board of Directors who do not carry this designation or affect the duties, obligations or liability of any other member of the Audit committee.

CODE OF ETHICS

The Registrant has adopted a code of business ethics for its directors, officers, employees and contractors. The Registrant's code is available on its website at www.transcanada.com. No waivers have been granted from any provision of the code during the 2015 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Audit committee - Pre-approval Policies and Procedures" and "Audit committee - External Auditor Service Fees" on page 40 of the TransCanada Corporation Annual information form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements, as defined in this Form, other than the guarantees and commitments described in Note 26 of the Notes to the audited consolidated financial statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on tabular disclosure of contractual obligations, see "Contractual obligations" in Management's discussion and analysis on page 90 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing Audit committee. The members of the Audit committee are:

Chair:	**S.A. Vanaselja**
Members:	**K.E. Benson**
	D.H. Burney
	J.E. Lowe
	M.P. Salomone
	D.M.G. Stewart

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 document may include information about the following, among other things:

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

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

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

Assumptions

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

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits

- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest, tax and foreign exchange rates
- weather
- cybersecurity
- 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 U.S. Securities and Exchange Commission (SEC).

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

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSCANADA CORPORATION

Per: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND
Executive Vice-President, Corporate Development and Chief Financial Officer

Date: February 11, 2016

DOCUMENTS FILED AS PART OF THIS REPORT

EXHIBITS

13.1	TransCanada Corporation Annual information form for the year ended December 31, 2015.
13.2	Management's discussion and analysis (included on pages 7 through 118 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders).
13.3	2015 Audited consolidated financial statements (included on pages 119 through 183 of the TransCanada Corporation 2015 Management's discussion and analysis and audited consolidated financial statements to shareholders), including the auditors' report thereon and the Report of Independent Registered Public Accounting Firm on the effectiveness of TransCanada's internal control over financial reporting as of December 31, 2015.
23.1	Consent of KPMG LLP, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
32.2	Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

TransCanada Corporation

2015 Annual information form

February 10, 2016

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Presentation of information

Throughout this Annual information form (**AIF**), the terms, *we*, *us*, *our*, *the Company* and *TransCanada* mean TransCanada Corporation and its subsidiaries. In particular, *TransCanada* includes references to TransCanada PipeLines Limited (**TCPL**). Where TransCanada is referred to with respect to actions that occurred prior to its 2003 plan of arrangement (**Arrangement**) with TCPL, which is described in the *TransCanada Corporation - Corporate structure* section below, such actions were taken by TCPL or its subsidiaries. The term *subsidiary*, when referred to in this AIF, with reference to TransCanada means direct and indirect wholly owned subsidiaries of, and legal entities controlled by, TransCanada or TCPL, as applicable.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2015 (**Year End**). Amounts are expressed in Canadian dollars unless otherwise indicated. Information in relation to metric conversion can be found at *Schedule A* to this AIF. The *Glossary* found at the end of this AIF contains certain terms defined throughout this AIF and abbreviations and acronyms that may not otherwise be defined in this document.

Certain portions of TransCanada's Management's discussion and analysis dated February 10, 2016 (**MD&A**) are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TransCanada's profile.

Financial information is presented in accordance with United States GAAP. We use certain financial measures that do not have a standardized meaning under GAAP and therefore they may not be comparable to similar measures presented by other entities. Refer to the *About this document – Non-GAAP measures* section of the MD&A for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents, which section of the MD&A is incorporated by reference herein.

Forward-looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains certain information that is forward-looking and is subject to important risks and uncertainties. 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 document may include information about the following, among other things:

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

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

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

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financing 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 pipelines businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in 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 material
- access to capital markets
- interest, tax and foreign exchange rates
- weather
- cybersecurity
- 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.

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

TransCanada Corporation

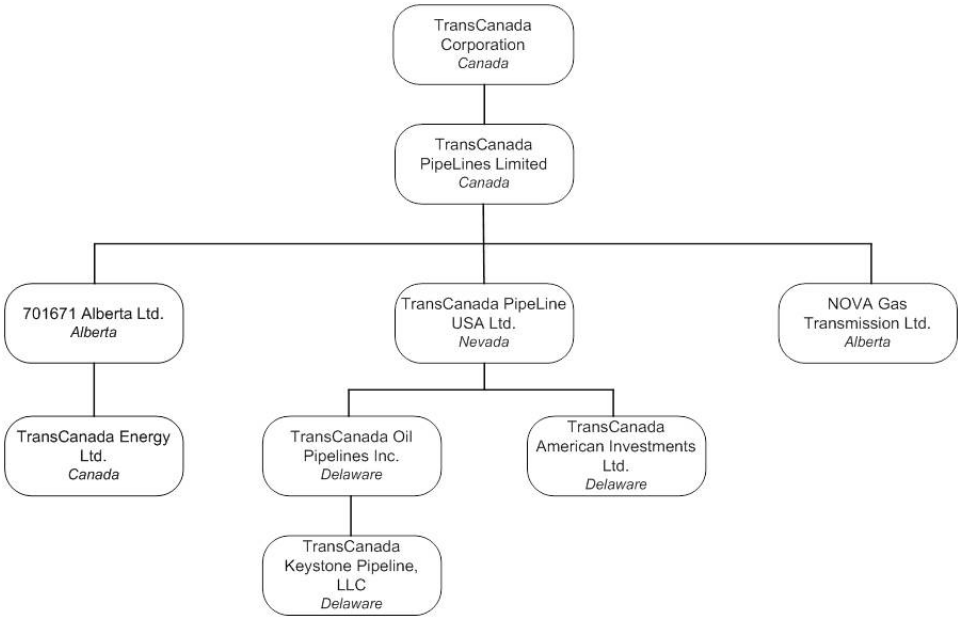
CORPORATE STRUCTURE

Our head office and registered office are located at 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporations Act* (**CBCA**) on February 25, 2003 in connection with the Arrangement, which established TransCanada as the parent company of TCPL. The Arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the Arrangement became effective May 15, 2003. Pursuant to the Arrangement, the common shareholders of TCPL exchanged each of their TCPL common shares for one common share of TransCanada. The debt securities and preferred shares of TCPL remained obligations and securities

of TCPL (the preferred shares of TCPL have been subsequently redeemed). TCPL continues to carry on business as the principal operating subsidiary of TransCanada. TransCanada does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TransCanada's subsidiaries.

INTERCORPORATE RELATIONSHIPS

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TransCanada's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the total consolidated assets of TransCanada as at Year End or revenues that exceeded 10 per cent of the total consolidated revenues of TransCanada for the year then ended. TransCanada beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares in each of these subsidiaries.



The above diagram does not include all of the subsidiaries of TransCanada. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets of TransCanada as at Year End or total consolidated revenues of TransCanada for the year then ended.

General development of the business

We operate our business in three segments:*Natural Gas Pipelines*, *Liquids Pipelines* and *Energy*. Natural Gas Pipelines and Liquids Pipelines are principally comprised of our respective natural gas and liquids pipelines in Canada, the U.S. and Mexico as well as our regulated natural gas storage operations in the U.S. Energy includes our power operations and the non-regulated natural gas storage business in Canada.

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Liquids Pipelines and Energy businesses, respectively, and certain acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years and year to date in 2016. Further information about changes in our business that we expect to occur during the current financial year can be found in the *Natural Gas Pipelines – Outlook, Liquids Pipelines – Outlook* and *Energy – Outlook* sections of the MD&A, which sections of the MD&A are incorporated by reference herein.

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Date	Description of development
Canadian Regulated Pipelines	
NGTL SYSTEM	
January 2013	The NEB issued its recommendation to the Governor-in-Council that the proposed Chinchaga Expansion component of the Komie North project be approved, but denied the proposed Komie North Extension component.
April 2013	The Leismer-Kettle River Crossover project was placed into service. The cost of the expansion was $150 million.
March 2014	We received an NEB Safety Order (the **Order**) in response to the recent pipeline releases on the NGTL System. The Order required us to reduce the maximum operating pressure on three per cent of NGTL's pipeline segments. We filed a request for a review and variance of the Order that would minimize gas disruptions while still maintaining a high level of safety, which the NEB granted in April 2014 subject to certain conditions. We accelerated components of our integrity management program to address the NEB Order.
March 2014	The NEB approved approximately $400 million in NGTL facility expansions.
Fourth Quarter 2014	We continued to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern British Columbia (**B.C.**) from unconventional gas plays and substantive growth in intra-basin delivery markets. This demand growth was driven primarily by oil sands development, gas-fired electric power generation and expectations of B.C. west coast LNG projects.
First Quarter 2015	The NGTL System had approximately $6.7 billion of new supply and demand facilities under development and we continued to advance several of these capital expansion projects by filing the regulatory applications with the NEB. We also received additional requests for firm receipt service.
Fourth Quarter 2015 / First Quarter 2016	In 2015, we placed approximately $350 million of facilities in service. For 2016, the NGTL System continues to develop a further approximately $7.3 billion of new supply and demand facilities. We have approximately $2.3 billion of facilities that have received regulatory approval with approximately $450 million currently under construction. We have filed for approval for a further approximately $2.0 billion of facilities which are currently under regulatory review. Applications for approval to construct and operate an additional $3.0 billion of facilities have yet to be filed. Included in our capital program is the recently announced 2018 expansion of a further $600 million of facilities required on the NGTL System. The 2018 expansion includes multiple projects totaling approximately 88 km (55 miles) of 20-to 48-inch diameter pipeline, one new compressor, approximately 35 new and expanded meter stations and other associated facilities. Applications to construct and operate the various components of the 2018 expansion program will be filed with the NEB between second quarter and fourth quarter 2016. Subject to regulatory approvals, construction is expected to start in 2017, with all facilities expected to be in service in 2018.
North Montney Mainline	
August 2013	We signed agreements for firm gas transportation services to underpin the development of a major pipeline extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. We also entered into arrangements with other parties for transportation services that will utilize the North Montney Mainline project facilities.
June 2015	The NEB approved the $1.7 billion North Montney Mainline project subject to certain terms and conditions. Under one of these conditions, construction on the North Montney Mainline project can only begin after a positive final investment decision (**FID**) has been made on the proposed Pacific NorthWest (**PNW**) LNG project. The North Montney Mainline will provide substantial new capacity on the NGTL System to meet the transportation requirements associated with rapidly increasing development of natural gas resources in the Montney supply basin in northeastern B.C. The project will connect Montney and other WCSB supply to both existing and new natural gas markets, including LNG markets. The North Montney Mainline project will consist of two large diameter 42-inch pipeline sections, Aitken Creek and Kahta, totaling approximately 301 km (187 miles) in length, and associated metering facilities, valve sites and compression facilities. The project will also include an interconnection with our proposed Prince Rupert Gas Transmission Project (**PRGT**) to provide natural gas supply to the proposed PNW LNG liquefaction and export facility near Prince Rupert, B.C. We expect to have the Aitken Creek and Kahta sections in service in 2017.
Merrick Mainline	
June 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, with the expectation for the Merrick Mainline to be in service in first quarter 2020. The Merrick Mainline pipeline will transport natural gas sourced through the NGTL System to the inlet of the proposed Pacific Trail Pipeline terminating at the Kitimat LNG Terminal near Kitimat, B.C.
First Quarter 2016	The proposed Merrick Mainline pipeline project has been delayed. In late 2015, the Kitimat LNG partners advised us that they are re-phasing the pace of Kitimat LNG facility development. Since the Merrick Mainline is dependent upon the construction of the downstream infrastructure, the in-service date of the Merrick Mainline will be no earlier than 2021. The Merrick Mainline is a $1.9 billion project that will consist of approximately 260 kilometres (161 miles) of 48-inch diameter pipe.

Date	Description of development
NGTL Revenue Requirement Settlements	
August 2013	We reached settlement of the NGTL System annual revenue requirement for the years 2013 and 2014 with shippers and other interested parties (the **NGTL 2013 – 2014 Settlement**). The settlement fixed the ROE at 10.10 per cent on 40 per cent deemed common equity, established an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixed the OM&A costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We also requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application.
November 2013	The NEB approved the NGTL 2013 - 2014 Settlement and final 2013 rates, as filed, in November 2013.
October 2014	We reached a revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement included no changes to the ROE 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 OM&A expense amount. The settlement was filed with the NEB in October 2014.
February 2015	We received NEB approval for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include continuation of the 2014 ROE of 10.10 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount that is based on an escalation of 2014 actual costs.
December 2015	We reached a two-year revenue requirement agreement with customers and other interested parties on the annual costs, including return on equity and depreciation required to operate the NGTL System for 2016 and 2017. The agreement fixes the equity return at 10.1 per cent on 40 per cent deemed common equity, establishes depreciation at a forecast composite rate of 3.16 per cent and fixes OM&A costs at $225 million annually. An incentive mechanism for variances will enable NGTL to capture savings from improved performance and provide for the flow-through of all other costs, including pipeline integrity expenses and emissions costs. NGTL filed on December 1, 2015 with the NEB for approval of the agreement.
CANADIAN MAINLINE	
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016.
Mainline Settlement & Tolls and Tariff Applications and LDC Settlement	
March 2013	We received the NEB decision on our Canadian Restructuring Proposal application to change the business structure and the terms and conditions of service for the Canadian Mainline. The NEB decision established a Toll Stabilization Account (**TSA**) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five year term of the decision. The NEB decision also identified certain circumstances that would require a new tolls application prior to the end of the five year term. One of those circumstances is if the TSA balance becomes positive, which occurred in 2013. Subsequently, we filed a review and variance application with the NEB in May 2013, which was dismissed in June 2013 and the NEB set out a process to consider the tariff revisions.
July 2013	The NEB released its reasons for the dismissal of our review and variance application. Additional changes to the Canadian Mainline's tariff were considered by the NEB as a separate application which was heard in an oral hearing. We began implementation of the NEB decision related to the Canadian Restructuring Proposal. The implementation of the NEB decision was a key priority in 2013 and with the ability to price discretionary services at market prices we were able to essentially meet our overall cost of service requirements for 2013.
September 2013	The Canadian Mainline and the three largest Canadian local distribution companies (**LDCs**) entered into a settlement (**LDC Settlement**) which was filed with the NEB for approval in December 2013. The LDC Settlement proposed to establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculated tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also included an incentive mechanism that required a $20 million (after tax) annual contribution by us from 2015 to 2020, which could have resulted in a range of ROE outcomes from 8.70 per cent to 11.50 per cent. The LDC Settlement would have enabled the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement was intended to provide a market driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retained pricing flexibility for discretionary services and implemented certain tariff changes and new services as required by the terms of the settlement.
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.
November 2014	Following a hearing, the NEB approved the Canadian Mainline's 2015 - 2030 Tolls and Tariff Application (the **NEB 2014 Decision**) which superseded the NEB 2013 Decision. The application reflected components of the LDC Settlement. In 2014, the Canadian Mainline operated under the NEB's decision for the years 2013-2017, which included an approved ROE of 11.5 per cent on deemed common equity of 40 per cent and an incentive mechanism based on total net revenues.

Date	Description of development
First Quarter 2015	In 2015, the Canadian Mainline began operating under the NEB 2014 Decision. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 per cent to 11.5 per cent. This decision also included an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from us. Toll stabilization is achieved through the continued use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over the six-year fixed toll term.
August 2015	TransCanada announced it had reached an agreement with the eastern LDCs that resolves the LDCs' issues with Energy East and the Eastern Mainline Project.
Eastern Mainline Project	
May 2014	We filed a project description with the NEB for the Eastern Mainline Project.
October 2014	An application was filed with the NEB for the Energy East project and to transfer a portion of the Canadian Mainline from natural gas service to crude oil service. An application was also filed for the Eastern Mainline Project, consisting of new gas facilities in southeastern Ontario required as a result of the proposed transfer of Mainline assets to crude oil service for the Energy east project.
August 2015	TransCanada announced it has reached an agreement with eastern LDCs that resolved their issues with Energy East and the Eastern Mainline Project.
December 2015	Application amendments were filed that reflect the agreement we announced in August 2015 with eastern LDCs resolving their issues with Energy East and the Eastern Mainline Project. The agreement provides gas consumers in eastern Canada with sufficient natural gas transmission capacity and provides for reduced natural gas transmission costs. The Eastern Mainline Project capital cost is now estimated to be $2.0 billion with the increase in the cost estimate due to the revised project scope resulting from the LDC agreement and updated cost estimates. The Eastern Mainline Project is conditioned on the approval and construction of the Energy East pipeline.
January 2016	The Canadian federal government announced interim measures for its review of the Energy East pipeline project. The government announced it will undertake additional consultations with aboriginal groups, help facilitate expanded public input into the NEB, and assess upstream GHG emissions associated with the project. The government will seek a six month extension to the NEB's legislative review and a three month extension to the legislative time limit for the government's decision. We are reviewing these changes and will assess the impacts to the Eastern Mainline Project.
Other Canadian Mainline Expansions	
November 2014	In addition to the Eastern Mainline Project, we executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new facilities, or modifications to existing facilities. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in eastern Canada.
First Quarter 2016	In addition to the Eastern Mainline Project, new facilities investments totaling approximately $700 million over the 2016 to 2017 period in the Eastern Triangle portion of the Canadian Mainline are required to meet contractual commitments from shippers.
ANR Pipeline	
October 2013	We concluded a successful binding open season. We executed firm transportation contracts for 350 MMcf/d at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal project, entailing modifications to existing facilities. The project substantially increases our ability to receive gas on ANR's Southeast Main Line (**SEML**) from the Utica/Marcellus shale areas.
March 2014	We secured nearly 2.0 Bcf/d of additional firm natural gas transportation commitments for existing and expanded capacity on ANR Pipeline's SEML. The capacity sales and expansion projects include reversing the Lebanon Lateral in western Ohio, additional compression at Sulphur Springs, Indiana, expanding the Rockies Express pipeline interconnect near Shelbyville, Indiana and 600 MMcf/d of capacity as part of a reversal project on the SEML. Capital costs associated with the ANR System expansions required to bring the additional capacity to market are currently estimated to be US$150 million. The capacity was subscribed at maximum rates for an average term of 23 years with approximately 1.25 Bcf/d of new contracts beginning service in late 2014. These secured contracts on the SEML will move Utica and Marcellus shale gas to points north and south on the system. ANR is also assessing further demand from our customers to transport natural gas from the Utica/Marcellus formation, which is expected to result in incremental opportunities to enhance and expand the system.
January 2016	ANR Pipeline filed a Section 4 Rate Case that requests an increase to ANR's maximum transportation rates. Shifts in ANR's traditional supply sources and markets, necessary operational changes, needed infrastructure updates, and evolving regulatory requirements are driving required investment in facility maintenance, reliability and system integrity as well as an increase in operating costs that have resulted in the current tariff rates not providing a reasonable return on our investment. We will also pursue a collaborative process to find a mutually beneficial outcome with our customers through settlement negotiations. ANR's last rate case filing was more than 20 years ago.

Date	Description of development
U.S. Pipelines	
Sale of GTN Pipeline, Bison Pipeline and Portland Natural Gas Transmission System (PNGTS) to TC PipeLines, LP (TCLP)	
July 2013	We sold an additional 45 per cent interest in each of Gas Transmission Northwest LLC (**GTN**) and Bison Pipeline LLC (**Bison**) to TCLP for an aggregate purchase price of US$1.05 billion. We continued to hold a 30 per cent direct ownership interest in both pipelines.
October 2014	We closed the sale of our remaining 30 per cent interest in Bison to TCLP for cash proceeds of US$215 million.
April 2015	We closed the sale of our remaining 30 per cent interest in GTN to TCLP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$246 million in cash, the assumption of US$98 million in proportional GTN debt and US$95 million of new Class B units of TCLP.
January 2016	We closed the sale of 49.9 per cent of our total 61.7 per cent interest in PNGTS to TCLP for US$223 million including the assumption of US$35 million of proportional PNGTS debt.
TC Offshore	
December 2015	We entered into an agreement to sell TC Offshore to a third party and expect the sale to close in early 2016. As a result, at December 31, 2015, the related assets and liabilities were classified as held for sale and were recorded at their fair values less costs to sell. This resulted in a pre-tax loss provisions of $125 million recorded in 2015.
Great Lakes	
November 2013	Great Lakes received FERC approval for a rate settlement with its shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from its recourse rate contracts. The settlement included a 17 month moratorium through March 2015 and required us to have new rates in effect by January 1, 2018.
February 2016	We reduced forecasted cash flows from the reporting unit for the next ten years as compared to those utilized in previous impairment tests. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$386 million at December 31, 2015 (2014 – US$243 million).
Northern Border	
January 2013	Northern Border secured a final settlement agreement with its shippers that the FERC approved in December 2012, effective January 2013. The settlement rates for long haul transportation were approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also included a three year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.
Mexican Pipelines	
Topolobampo and Mazatlan Pipeline Projects	
First Quarter 2016	Permitting, engineering, and construction activities are advancing as planned for these two northwest Mexico pipelines. The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and a cost of US$1 billion that will deliver gas to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico. The Mazatlan project is a 413 km (257 miles), 24-inch pipeline running from El Oro to Mazatlan within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million. Both projects are supported by 25-year contracts with the CFE and are in their final construction stages with expected in-service dates in late 2016.
Tuxpan-Tula Pipeline	
November 2015	We were awarded the contract to build, own and operate the US$500 million, 36 inch, 250 km (155 miles) Tuxpan-Tula pipeline with a contracted capacity of 886 MMcf/d for 25 years with the CFE. The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to each of those jurisdictions as well as the central region of Mexico. The pipeline will serve new power generating facilities as well as existing power plants that plan to switch from fuel oil to natural gas as their base fuel. Physical construction is expected to begin in 2016 with a planned in-service date in fourth quarter 2017.

Date	Description of development
Tamazunchale Pipeline Extension Project	
November 2014	Construction of the US$600 million extension was completed. Delays from the original service commencement date in March 2014 were attributed primarily to archeological findings along the pipeline route. Under the terms of the transportation service agreement, these delays were recognized as a force majeure with provisions allowing for collection of revenue from the original service commencement date.
Guadalajara	
First Quarter 2013	The compressor station went into service.

International Gas Pipelines

Gas-Pacifico/INNERGY Sale	
November 2014	We closed the sale of our 30 per cent equity interests in Gas Pacifico/INNERGY at a price of $9 million. This sale marked our exit from the Southern Cone region of South America.

LNG Pipeline Projects

Prince Rupert Gas Transmission	
January 2013	We were selected to design, build, own and operate the proposed PRGT pipeline. We were focused on Aboriginal, community, landowner and government engagement as the PRGT advanced through the regulatory process with the Environmental Assessment Office (**EAO**). We continued to refine our study corridor based on consultation and detailed studies.
November 2014	We received an Environmental Assessment Certificate (**EAC**) from the B.C. EAO. We have submitted our pipeline permit applications to the B.C. Oil and Gas Commission (**OGC**) for construction of the pipeline. We made significant changes to the project route since first announced, increasing it by 150 km (93 miles) to 900 km (559 miles), taking into account Aboriginal and stakeholder input. We continued to work closely with Aboriginal groups and stakeholders along the proposed route to create and deliver appropriate benefits to all impacted groups. We concluded a benefits agreement with the Nisga'a First Nation to allow 85 km (52 miles) of the proposed natural gas pipeline to run through Nisga'a Lands.
June 2015	PNW LNG announced a positive FID for its proposed liquefaction and export facility, subject to two conditions. The first condition, approval by the Legislative Assembly of B.C. of a Project Development Agreement between PNW LNG and the Province of B.C., was satisfied in July 2015. The second condition is a positive regulatory decision on PNW LNG's environmental assessment by the Government of Canada, which has not yet been received.
Third Quarter 2015	We received all remaining permits from the B.C. OGC which completes the eleven permits required to build and operate PRGT. Environmental permits for the project were received in November 2014 from the B.C. EAO. With these permits, PRGT has all of the primary regulatory permits required for the project. We remain on target to begin construction following confirmation of a FID by PNW LNG. The in-service date for PRGT is estimated to be 2020 but will be aligned with PNW LNG's liquefaction facility timeline.
February 2016	We are continuing our engagement with Aboriginal groups and have now signed project agreements with ten First Nation groups along the pipeline route. Project agreements outline financial and other benefits and commitments that will be provided to each First Nation for as long as the project is in service. PRGT is a 900 km (559 miles) natural gas pipeline that will deliver gas from the Montney producing region at an expected interconnect on the NGTL System near Fort St. John, B.C. to PNW LNG's proposed LNG facility near Prince Rupert, B.C. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.
Coastal GasLink	
January 2014	We filed the EAC application with the B.C. EAO. We focused on community, landowner, government and Aboriginal engagement as the project advanced through the regulatory process. The pipeline would be placed in service near the end of the decade, subject to a FID to be made by LNG Canada after obtaining final regulatory approvals. The 670 km (416 miles) pipeline is expected to have an initial capacity of 1.7 Bcf/d and will transport natural gas from the Montney gas producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG export facility near Kitimat, B.C.
October 2014	The EAO issued an EAC for Coastal GasLink. In 2014, we also submitted applications to the B.C. OGC for the permits required under the *Oil and Gas Activities Act* to build and operate Coastal GasLink.

Date	Description of development
First Quarter 2016	We are continuing our engagement with Aboriginal groups along our pipeline route and have now announced long-term project agreements with eleven First Nations. These project agreements outline financial and other benefits and commitments that will be provided to each First Nation for as long as the pipeline remains in service. We also continue to engage with stakeholders along the pipeline route and are progressing detailed engineering and construction planning work to refine the capital cost estimate. In response to feedback received, we have applied for a minor route amendment to the B.C. EAO in order to provide an option in the area of concern. It is anticipated that approval for this route amendment will be received in first quarter 2016. We have received eight of ten pipeline and facilities permits from the B.C. OGC and anticipate receiving the remaining two permits in first quarter 2016. With these permits, Coastal GasLink will hold all of the required primary regulatory permits for the project. The LNG Canada participants have indicated they expect to make a FID later in 2016. We remain optimistic that their project will proceed and our development activities for the Coastal GasLink project remain fully coordinated with their project schedule. Our pipeline in-service date will be scheduled to coincide with the operational requirements of the LNG Canada facility to be built in Kitimat, B.C. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.
Alaska LNG Project	
April 2014	The State of Alaska passed new legislation to provide a framework for us, the three major North Slope producers (the **ANS Producers**), and the Alaska Gasline Development Corp. (**AGDC**) to advance the development of an LNG export project.
June 2014	We executed an agreement with the State of Alaska to abandon the previous Alaska to Alberta project governance and framework and executed a new precedent agreement where we will act as the transporter of the State's portion of natural gas under a long-term shipping contract in the Alaska LNG Project. We also entered into a Joint Venture Agreement with the three major ANS Producers and AGDC to commence the pre-front end engineering and design (**pre-FEED**) phase of Alaska LNG Project. The pre-FEED work was anticipated to take two years to complete with our share of the cost to be approximately US$100 million. The precedent agreement also provided us with full recovery of development costs in the event the project did not proceed.
November 2015	We sold our interest in the Alaska LNG project to the State of Alaska. The proceeds of US$65 million from this sale provide a full recovery of costs incurred to advance the project since January 1, 2014 including a carrying charge. With this sale, our involvement in developing a pipeline system for commercializing Alaska North Slope natural gas ceases.

Further information about developments in the Natural Gas Pipelines business, including changes that we expect will occur in the current financial year, can be found in the MD&A in the *About our business – Our strategy, Natural Gas Pipelines – Results, Natural Gas Pipelines – Outlook, Natural Gas Pipelines – Understanding the Natural Gas Pipelines business* and *Natural Gas Pipelines – Significant events* sections, which sections of the MD&A are incorporated by reference herein.

DEVELOPMENTS IN THE LIQUIDS PIPELINES BUSINESS

Date	Description of development
Keystone Pipeline System	
January 2014	We finished constructing the 780 km (485 miles) 36-inch pipeline of the Gulf Coast extension of the Keystone Pipeline System from Cushing, Oklahoma to the U.S. Gulf Coast, and crude oil transportation service on the project began. Average pipeline capacity was 520,000 Bbl/d for the first year of operation. The completion of the Gulf Coast extension in January 2014 expanded the Keystone Pipeline System to a 4,247 km (2,639 miles) pipeline system that transports crude oil from Hardisty, Alberta, to markets in the U.S. Midwest and the U.S. Gulf Coast.
Fourth Quarter 2015	We secured additional long term contracts bringing our total contract position up to 545,000 Bbl/d.
CITGO Sour Lake Pipeline	
Second Quarter 2015	We entered into an agreement with CITGO Petroleum (**CITGO**) to construct a US$65 million pipeline connection between the Keystone Pipeline System to provide access to CITGO's Sour Lake, Texas terminal, which supplies their 425,000 Bbl/d Lake Charles, Louisiana refinery. The connection is targeted to be operational in fourth quarter 2016.
Cushing Marketlink	
September 2014	Construction was completed.
Houston Lateral and Terminal	
Third Quarter 2015	Construction continued on the 77 km (48 miles) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in second quarter 2016.
January 2016	We entered into an agreement with Magellan Midstream Partners L.P. (**Magellan**) to connect our Houston Terminal to Magellan's Houston and Texas City, Texas delivery system. We will own 50 per cent of this US$50 million pipeline project which will enhance connections for our Keystone Pipeline System to the Houston market. The pipeline is expected to be operational during the first half of 2017, subject to the receipt of all necessary rights-of-way, permits and regulatory approvals.
Keystone XL	
January 2013	The Nebraska Department of Environmental Quality (**NDEQ**) issued its final evaluation report on our proposed reroute of Keystone XL to the Governor of Nebraska. In January 2013, the Governor of Nebraska approved our proposed reroute. The NDEQ issued its final evaluation report noting that construction and operation of Keystone XL is expected to have minimal environmental impacts in Nebraska.
March 2013	The DOS released its Draft Supplemental Environmental Impact Statement for Keystone XL. The impact statement reaffirmed construction of the 830,000 Bbl/d Keystone XL project would not result in any significant impact to the environment.
January 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. 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 GHG emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period of up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment.
February 2014	A Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, had the authority to approve an alternative route through Nebraska for Keystone XL.
April 2014	The DOS announced that the national interest determination period had been extended indefinitely to allow them to consider the potential impact of the Nebraska portion of the pipeline route.
September 2014	Nebraska's Attorney General filed an appeal which was heard by the Nebraska State Supreme Court. We filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (**PUC**). This certification confirmed that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted continued to be satisfied.
January 2015	The Nebraska State Supreme Court vacated the lower court's ruling that the law was unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remains valid. Landowners have filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds.

Date	Description of development
November 2015	The decision on the Keystone XL Presidential permit application was delayed throughout 2015 by the DOS and was ultimately denied in November 2015. At December 31, 2015, as a result of the denial of the Presidential permit, we evaluated our investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion aftertax). The impairment charge was based on the excess of the carrying value of $4.3 billion over the fair value of $621 million, which includes $93 million fair value for Keystone Hardisty Terminal. The Keystone Hardisty Terminal remains on hold with an estimated in-service date to be driven by market need. The calculation of this impairment is discussed further in the *Other information – Critical accounting estimates* section of the MD&A. Also in November 2015, we withdrew our application to the Nebraska Public Service Commission for approval of the route for Keystone XL in the state. The application was initially filed in October 2015. The withdrawal was made without prejudice to potentially refile if we elect to pursue the project.
January 2016	On January 5, 2016, the South Dakota PUC accepted Keystone's certification that it continues to comply with the conditions in its existing 2010 permit authority in the state. On January 6, 2016, we filed a Notice of Intent to initiate a claim under Chapter 11 of NAFTA in response to the U.S. Administration's decision to deny a Presidential permit for the Keystone XL Pipeline on the basis that the denial was arbitrary and unjustified. Through the NAFTA claim, we are seeking to recover more than US$15 billion in costs and damages that we estimated to have suffered as a result of the U.S. Administration's breach of its NAFTA obligations. This litigation is in a preliminary stage and the likelihood of success and resulting impact on our financial position or results of operation is unknown at this time. On the same day, we filed a lawsuit in the U.S. Federal Court in Houston, Texas, asserting that the U.S. President's decision to deny construction of Keystone XL exceeded his power under the U.S. Constitution. The federal court lawsuit does not seek damages, but rather a declaration that the permit denial is without legal merit and that no further Presidential action is required before construction of the pipeline can proceed. We remain supportive of Keystone XL and continue to review our options, including filing a new application for a cross-border permit.
Energy East Pipeline	
April 2013	We announced that we were holding an open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets. The open season followed a successful expression of interest phase and discussions with prospective shippers.
August 2013	We announced that we were moving forward with the 1.1 million Bbl/d Energy East Pipeline as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from western Canada to eastern refineries and export terminals. The project was estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. We began Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning.
March 2014	We filed the project description for the Energy East Pipeline with the NEB. This was the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline.
October 2014	We filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline and terminal facilities with the NEB. Subject to regulatory approvals, the pipeline was anticipated to commence deliveries by the end of 2018.
April 2015	We announced that the proposed marine terminal and associated tank terminal in Cacouna, Québec will not be built as a result of the recommended reclassification of the beluga whale, indigenous to the site, as an endangered species.
November 2015	Following consultation with stakeholders and shippers, we announced the intention to amend the Energy East application to remove a port in Québec and proceed with a single marine terminal in Saint John, New Brunswick.
December 2015	We filed an amendment to the existing project application with the NEB that adjusted the proposed route, scope and capital cost of the project reflecting refinement and scope change including the removal of the port in Québec. The project will continue to serve the three eastern Canadian refineries along the route in Montréal and Québec City, Québec and Saint John, New Brunswick.
January 2016	Changes to the project schedule and scope, as reflected in the amendment, contributed to a revised project capital cost of $15.7 billion, excluding the transfer of Canadian Mainline natural gas assets. Of the total long-term shipping commitments for the project of 995,000 Bbl/d, with an average term of 19 years, 725,000 bbl/d designate the Québec refineries, or Saint John, New Brunswick as delivery points. A total of 270,000 Bbl/d remains under contract for delivery to the Québec market, including a Québec based marine terminal and without a Saint John, New Brunswick delivery point. Discussions are ongoing with those shippers to remove the Québec marine terminal from the terms of.their shipping contracts. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries by the end of 2020. However, on January 27, 2016, the Canadian federal government announced interim measures for pipeline reviews, including in respect of the Energy East project. The government announced it will undertake additional consultations with aboriginal groups, help facilitate expanded public input into the NEB and assess Energy East's impact on upstream GHG emissions. The government will seek a six month extension to the NEB's legislative review and a three month extension to the legislative time limit for the government's decision which will extend the total review time to 27 months. We are currently reviewing these changes to assess their impact to the project.

Date	Description of development
Northern Courier Pipeline	
April 2013	We filed a permit application with the Alberta Energy Regulator (**AER**) after completing the required Aboriginal and stakeholder engagement and associated field work.
October 2013	Suncor Energy Inc. (Suncor) announced that Fort Hills Energy Limited Partnership was proceeding with the Fort Hills oil sands mining project and that it expected to begin producing crude oil in 2017. The Northern Courier Pipeline will transport crude oil from the Fort Hills mine site to Suncor's tank facilities located north of Fort McMurray.
July 2014	The AER issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has started on the pipeline.
First Quarter 2016	Construction continues on the pipeline system to transport bitumen and diluent between the Fort Hills mine site and Suncor terminal located north of Fort McMurray, Alberta. The project is fully underpinned by long term contracts with the Fort Hills partnership. We expect the pipeline system to be ready for service in 2017.
Heartland Pipeline and TC Terminals	
May 2013	We announced we had reached binding long-term shipping agreements to build, own and operate the Heartland Pipeline and TC Terminals projects, and filed a permit application for the terminal facility. In October 2013, we filed a permit application for the pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.
February 2014	The application for the terminal facility was approved by the AER.
October 2014	Construction commenced on the terminal and has since been delayed and the in-service date for the projects will be determined and aligned with industry conditions and our customer's requirements. The Heartland Pipeline is a crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta. TC Terminals is a terminal facility in the Heartland industrial area north of Edmonton, Alberta located at the start of the Heartland Pipeline.
Grand Rapids Pipeline	
May 2013	We filed a permit application with the AER for the Grand Rapids Pipeline, a dual 36-inch/20-inch crude oil and diluent pipeline system connecting producing areas northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland, Alberta region after completing the required Aboriginal and stakeholder engagement and associated field work. Our partner has also entered into a long-term transportation service contract in support of the Grand Rapids Pipeline. Along with our partner, we will each own 50 per cent of the project and we will operate the system.
October 2014	The AER issued a permit approving our application to construct and operate the Grand Rapids Pipeline. Construction is progressing on phase one, which includes a 20-inch pipeline from northern Alberta to Edmonton, Alberta and a 36-inch pipeline between Edmonton and Fort Saskatchewan, Alberta. We anticipate phase one to begin crude oil transportation service in 2017. The construction of phase two, the larger 36-inch pipeline, is currently delayed and the in-service date will be subject to sufficient market demand. We will operate the Grand Rapids Pipeline once complete.
August 2015	We announced a joint venture between Grand Rapids and Keyera Corp. for provision of diluent transportation service on the 20-inch pipeline between Edmonton and Fort Saskatchewan, Alberta, which is anticipated to be in service in the second half of 2017. The joint venture will be incorporated into phase one of Grand Rapids and it will provide enhanced diluent supply alternatives to our shippers.
Upland Pipeline	
November 2014	We completed a successful binding open season for the Upland Pipeline. The commercial contracts we have executed for $600 million Upland Pipeline are conditioned on Energy East proceeding.
April 2015	We filed an application to obtain a U.S. Presidential permit for the Upland Pipeline. The pipeline will provide crude oil transportation from and between multiple points in North Dakota and interconnect with the Energy East Pipeline System at Moosomin, Saskatchewan. Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2020. The commercial contracts we have executed for Upland Pipeline are conditioned on the Energy East project proceeding.
January 2016	We are reviewing the Canadian federal government's interim measures for pipeline reviews and to assess their impact to Upland Pipeline.
Liquids Marketing	
2015	We established a liquids marketing business to expand into other areas of the liquids business value chain. The liquids marketing business will generate revenue by capitalizing on asset utilization opportunities by entering into short-term or long-term pipeline or storage terminal capacity contracts. Volatility in commodity prices and changing market conditions could impact the value of those capacity contracts. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management polices which are described in the *Other information - Risks and risk management* section of the MD&A.

Further information about developments in the Liquids Pipelines business, including changes that we can expect will occur in the current financial year, can be found in the MD&A in the *About our business – Our strategy, Liquids Pipelines – Results, Liquids Pipelines – Outlook, Liquids Pipelines – Understanding the Liquids Pipelines business* and *Liquids Pipelines – Significant events* sections, which sections of the MD&A are incorporated by reference herein.

DEVELOPMENTS IN THE ENERGY BUSINESS

Date	Description of development
Canadian Power	
Alberta Greenhouse Gas Emissions	
June 2015	The Alberta government announced a renewal and change to the SGER in Alberta. Since 2007, under the SGER, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions by 12 per cent below an average intensity baseline and a carbon levy of $15 per tonne is placed on emissions above this target. The changed regulations include an increase in the emissions reductions target to 15 per cent in 2016 and 20 per cent in 2017, along with an increase in the carbon levy to $20 per tonne in 2016 and $30 per tonne in 2017. Starting in 2018, coal-fired generators will pay $30 per tonne of CO2 on emissions above what Alberta's cleanest natural gas-fired plant would emit to produce an equivalent amount of electricity. While our Sundance and Sheerness PPAs are subject to this regulation, our inventory of carbon offset credits will mitigate some of these increased costs. The remaining compliance costs are expected to be somewhat recovered through increased market pricing but the full extent is not known at this time.
Napanee	
January 2015	We began construction activities on a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late-2017 or early-2018. Production from the facility is fully contracted with the IESO.
Bécancour	
June 2013	Hydro-Québec Distribution (**Hydro-Québec**) notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014. Hydro-Québec had notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013. Under the original agreement, Hydro-Québec had the option to extend the suspension on an annual basis until such time as regional electricity demand levels recover.
December 2013	We entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continued to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended.
May 2014	We received final approval from the Régie de l'énergie for the December 2013 amendment to the original suspension agreement with Hydro-Québec. In addition, Hydro-Québec exercised its option in the amended suspension agreement to extend suspension of all electricity generation to the end of 2017, and requested further suspension of generation to the end of 2018.
August 2015	We executed an agreement with Hydro-Québec to amend Bécancour's electricity supply contract. The amendment allows Hydro-Québec to dispatch up to 570 MW of firm peak winter capacity from the Bécancour facility for a term of 20 years commencing in December 2016. Annual payments received for this new service will be incremental to existing capacity payments earned under the agreement. In October 2015, the Régie de l'énergie approved the amended contract. We continue to receive capacity payments while generation is suspended.
Bruce Power	
April 2013	Bruce Power announced that it had reached an agreement with the Ontario Power Authority to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.
April 2013	Bruce Power returned Bruce A Unit 4 to service after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Bruce A Unit 4 to operate until at least 2021.
March 2014	Cameco Corporation sold its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We maintain an option to increase our Bruce B ownership percentage.

Date	Description of development
Fourth Quarter 2014	New Canadian federal legislation is expected to come into force in 2015 respecting the determination of liability and compensation for a nuclear incident in Canada resulting in personal injuries and damages. This proposed legislation will replace existing legislation which currently provides that the licensed operator of a nuclear facility has absolute and exclusive liability and limits the liability to a maximum of $75 million. The proposed new law is fundamentally consistent with the existing regime although the maximum liability will increase to $650 million and increase in increments over three years to a maximum of $1 billion. The operator will also be required to maintain financial assurances such as insurance in the amount of the maximum liability. Our indirect subsidiary owns 50 per cent of the common shares of Bruce Power Inc., the licensed operator of Bruce Power, and as such Bruce Power Inc. is subject to this liability in the event of an incident as well as the legislation's other requirements.
December 2015	Bruce Power entered into an agreement with the IESO to extend the operating life of the facility to the end of 2064. This new agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site. The amended agreement is effective January 1, 2016 and allows Bruce Power to immediately invest in life extension activities for Units 3 through 8. Our estimated share of investment in the Asset Management program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our estimated share of investment in the Major Component Replacement work that is expected to begin in 2020 is approximately $4 billion (2014 dollars). Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining Major Component Replacement investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits. The agreement has been structured to account for changing cost inputs over time, including ongoing operating costs and additional capital investments. Beginning in 2016, Bruce Power receives a uniform price of $65.73 per MWh for all units. This price will be adjusted over the term of the agreement to incorporate incremental capital investment and cost changes. In connection with this opportunity, we exercised our option to acquire an additional 14.89 per cent ownership interest in Bruce B for $236 million from the Ontario Municipal Employees Retirement System. Subsequent to this acquisition, Bruce A and Bruce B were merged to form a single partnership structure. In 2015, we recognized a $36 million charge, representing our proportionate share, on the retirement of Bruce Power debt in conjunction with this merger. We now hold a 48.5 per cent interest in this newly merged partnership structure.
Cancarb Limited and Cancarb Waste Heat Facility	
January 2014	We announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility.
April 2014	The sale of Cancarb Limited and its related power generation facility closed for gross proceeds of $190 million. We recognized a gain of $99 million, net of tax, in second quarter 2014.
Ontario Solar	
June 2013	We completed the acquisition of the first facility for $55 million as per our December 2011 agreement, pursuant to which we agreed to buy Ontario solar generation facilities with combined capacity of 86 MW from Canadian Solar Solutions Inc. (**Canadian Solar**) for approximately $500 million. Under the terms of the agreement, Canadian Solar will develop and build each of the nine solar facilities using photovoltaic panels. We buy each facility once construction and acceptance testing are complete and commercial operation begins. All power produced by the solar facilities is currently or will be sold under 20-year FIT contracts with the IESO.
September 2013	We completed the acquisition of two additional solar facilities for $99 million.
December 2013	We completed the acquisition of an additional solar facility for $62 million.
September 2014	We completed the acquisition of three additional solar facilities for $181 million.
December 2014	We acquired an additional solar facility for $60 million. Our total investment in the eight solar facilities is $457 million.

U.S. Power

Ravenswood	
September 2014	The 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage.
May 2015	The Ravenswood Generating Station returned to service after the September 2014 unplanned outage which resulted from a problem with the generator associated with the high pressure turbine. Insurance recoveries for this event are expected to be received in 2016. 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 although the recording of earnings will not coincide with lost revenues due to timing of the insurance proceeds.
Ironwood	
February 2016	We acquired the 778 MW Ironwood natural gas fired, combined cycle power plant located in Lebanon, Pennsylvania from Talen Energy Corporation for US$657 million before post closing adjustments. The Ironwood power plant delivers energy into the PJM power market and will provide us with a solid platform from which to continue to grow our wholesale, commercial and industrial customer base in this market area.

Date	Description of development
New York Power Business	
January 2014	Capacity prices in the New York market are established through a series of forward auctions and utilize a demand curve administered price for purposes of setting the monthly spot price. The demand curve, among other inputs, uses assumptions with respect to the expected cost of the most likely peaking generation technology applicable to new entrants to the market. In January 2014, the FERC accepted a new rate for the demand curve that was filed by the New York Independent System Operator as part of its triennial Demand Curve Reset (**DCR**) process. The filing changed the generation technology used in the DCR versus that used during the last reset process for New York City Zone J where Ravenswood operates. Average New York Zone J spot capacity prices were approximately 27 per cent higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014. Average New York Zone J spot capacity prices were approximately 18 per cent lower in 2015 than in 2014. The decrease in spot prices and the impact of hedging activities, resulted in lower realized capacity prices in New York in 2015. The lower spot capacity prices were primarily due to increased available operational supply in New York City's Zone J market. In 2014 we disclosed that the FERC announced a decision affecting future capacity auctions in New England Power Pool (**NEPOOL**) which we thought may potentially improve capacity price conditions in 2018 and beyond. Since the announcement, capacity prices have improved in 2018 and beyond for our assets that are located in NEPOOL.
Natural Gas Storage	
April 2014	We sold out interest in the Alaska LNG project to the State of Alaska. The proceeds from the sale provide a full recovery of costs incurred to advance the project since January 1, 2014 including a carrying charge. With this sale, our involvements in developing pipeline system for commercializing the Alaska North Slope natural gas ceases.

Further information about developments in the Energy business, including changes that we expect will occur in the current financial year, can be found in the MD&A in the *About our business – Our strategy, Energy – Results, Energy – Outlook, Energy – Understanding the Energy business* and *Energy – Significant events* sections, which sections of the MD&A are incorporated by reference herein.

Business of TransCanada

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Liquids Pipelines and Energy. At Year End and for the year then ended, Natural Gas Pipelines accounted for approximately 48 per cent of revenues and 48 per cent of our total assets, Liquids Pipelines accounted for approximately 17 per cent of revenues and 25 per cent of our total assets, and Energy accounted for approximately 36 per cent of revenues and 24 per cent of our total assets. The following table shows our revenues from operations by segment, classified geographically, for the years ended December 31, 2015 and 2014.

Revenues from operations *(millions of dollars)*	**2015**	**2014**
Natural Gas Pipelines		
Canada – Domestic	$2,848	$2,672
Canada – Export[1]	$829	$881
United States	$1,447	$1,163
Mexico	$259	$197
	$5,383	$4,913
Liquids Pipelines		
Canada – Domestic	—	—
Canada – Export[1]	$458	$432
United States	$1,421	$1,115
	$1,879	$1,547
Energy[2]		
Canada – Domestic	$1,029	$1,284
Canada – Export[1]	$5	$1
United States	$3,004	$2,440
	$4,038	$3,725
Total revenues[3]	$11,300	$10,185

1 Exports include pipeline revenues attributable to Canadian Pipeline and power deliveries to U.S. markets.
2 Revenues include sales of natural gas.
3 Revenues are attributed to countries based on country of origin of product or service.

The following is a description of each of TransCanada's three main areas of operations.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. Information about TransCanada's competitive position relating to the Natural Gas Pipelines business can be found in the MD&A in the *Natural Gas Pipelines – Understanding the Natural Gas Pipelines business* section, which section of the MD&A is incorporated by reference herein.

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

	Length	**Description**	**Effective ownership**
Canadian pipelines			
NGTL System	24,544 km (15,251 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%

	Length	Description	Effective ownership
Trans Québec & Maritimes (**TQM**)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
U.S. pipelines			
ANR Pipeline	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
Bison	488 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
GTN	2,216 km (1,377 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. upper Midwest. We effectively own 66.6 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28 per cent interest in TC PipeLines, LP	66.6%
Iroquois	669 km (416 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%
North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with a third-party pipeline on the California/Mexico border. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
Northern Border	2,264 km (1,407 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 14 per cent of the system through our interest in TC PipeLines, LP	14%
PNGTS	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. northeast. We effectively own 25.8 per cent of the system through the combination of 11.8 per cent direct ownership and our 28 per cent interest in TC PipeLines, LP. Prior to January 1, 2016 we had direct ownership of 61.7 per cent.	25.8%
Tuscarora	491 km (305 miles)	Transports natural gas from GTN to Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
TC Offshore[1]	958 km (595 miles)	Gathers and transports natural gas within the Gulf of Mexico with subsea pipeline and seven offshore platforms to connect in Louisiana with our ANR Pipeline system.	100%
Mexican pipelines			
Guadalajara	315 km (196 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
Tamazunchale	365 km (227 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to El Sauz, Queretaro	100%

	Length	Description	Effective ownership
Under construction			
Mazatlan Pipeline	413 km* (257 miles)	To deliver natural gas from El Oro to Mazatlan, Sinaloa in Mexico. Will connect to the Topolobampo Pipeline at El Oro	100%
Topolobampo Pipeline	530 km* (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
Tuxpan-Tula Pipeline	250 km* (155 miles)	The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to CFE combined-cycle power generating facilities in each of those jurisdictions as well as to the central and western regions of Mexico.	100%
NGTL 2016/17 Facilities	540 km* (336 miles)	An expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests received in 2014 on the NGTL System and expected to be completed between 2016 and 2018.	100%
In development			
Coastal GasLink	670 km* (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
Prince Rupert Gas Transmission	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
North Montney Mainline	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project	100%
Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
Eastern Mainline Project	279 km* (173 miles)	Pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project.	100%
NGTL 2018 Facilities	88 km* (55 miles)	An expansion program comprised of multiple projects of 20- to 48-inch diameter pipelines, one new compressor unit and multiple meter stations to meet new incremental firm service requests received in 2015 on the NGTL System and expected to be completed in 2018.	100%

* Final pipe lengths are subject to changes during construction and/or final design considerations.

[1] As at December 31, 2015, TC Offshore was classified as Assets held for sale. See the *Natural Gas Pipelines – Significant events* section of the MD&A for further information.

Further information about our pipeline holdings, developments and opportunities and significant regulatory developments which relate to Natural Gas Pipelines can be found in the MD&A in the *Natural Gas Pipelines – Results, Natural Gas Pipelines – Understanding the Natural Gas Pipelines business* and *Natural Gas Pipelines – Significant events* sections, which sections of the MD&A are incorporated by reference herein.

LIQUIDS PIPELINES BUSINESS

Our existing liquids pipeline infrastructure connects Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S. Gulf Coast. Our proposed future pipeline infrastructure would also connect Canadian and U.S. crude oil supplies to refining markets in eastern Canada and overseas export markets, and expand capacity for Canadian and U.S. crude oil access to U.S. markets.

We are the operator of all of the following pipelines and properties.

	Length	Description	Ownership
Liquids pipelines			
Keystone Pipeline System	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka Illinois, Cushing, Oklahoma, and Port Arthur, Texas	100%
Cushing Marketlink and Terminal		Terminal and pipeline facilities to transport crude oil from the market hub at Cushing, Oklahoma to the Port Arthur, Texas refining market on facilities that form part of the Keystone Pipeline System	100%
Under construction			
Houston Lateral and Houston Terminal	77 km (48 miles)	To extend the Keystone Pipeline System to the Houston, Texas refining market	100%
Grand Rapids Pipeline	460 km (287 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland, Alberta market region	50%
Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
In development			
Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
Keystone XL	1,897 km (1,179 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
Energy East Pipeline	4,600 km (2,850 miles)	To transport crude oil from western Canada to eastern Canadian refineries and export markets	100%
Upland Pipeline	460 km (285 miles)	To transport crude oil from, and between, multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan	100%

Further information about our pipeline holdings, developments and opportunities and significant regulatory developments which relate to Liquids Pipelines can be found in the MD&A in the *Liquids Pipelines – Results, Liquids Pipelines – Understanding the Liquids Pipelines business* and *Liquids Pipelines – Significant events* sections, which sections of the MD&A are incorporated by reference herein.

REGULATION OF THE NATURAL GAS AND LIQUIDS PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

The Canadian Mainline, NGTL System and Foothills System (collectively, the **Systems**) are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for these Canadian regulated natural gas transmission systems.

The NEB generally sets tolls that provide TransCanada the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for each of the Systems. Generally, Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years. The Canadian Mainline, however, operates under a fixed toll arrangement for its longer term firm transportation service and has the flexibility to price its shorter term and discretionary services in order to maximize its revenue. Further information relating to the decision from the NEB regarding the Canadian Restructuring Proposal as well as the LDC Settlement can be found in the *General Developments of the business – Developments in the Natural Gas Pipelines business – Mainline Settlement & Tolls and Tariff Applications and LDC Settlement* section above. In addition, the NGTL System recently reached a two year revenue requirement settlement that remains subject to NEB approval.

New facilities on or associated with the Systems are approved by the NEB before construction begins and the NEB regulates the operations of each of the Systems. Net earnings of the Systems may be affected by changes in investment base, the allowed ROE, and any incentive earnings.

West Coast LNG – Natural Gas Pipeline Projects

The Coastal GasLink and PRGT natural gas pipeline projects are being proposed and developed primarily under the regulatory regime administered by the OGC and the EAO. The OGC is responsible for overseeing oil and gas operations in B.C., including exploration, development, pipeline transportation and reclamation. The EAO is an agency that manages the review of proposed major projects in B.C., as required by the B.C. *Environmental Assessment Act*.

Liquids Pipelines

The NEB regulates the terms and conditions of service, including rates, facilities and the physical operation of the Canadian portion of the Keystone Pipeline System. The rates for transportation service on the Keystone Pipeline system are calculated in accordance with a methodology agreed to in transportation service agreements between Keystone and its shippers, and approved by the NEB.

Liquids Pipelines Projects

The Northern Courier Pipeline and Grand Rapids Pipeline projects are currently under construction and are being developed primarily under the regulatory regime administered by the AER. The AER administers approvals required to construct and operate the pipelines and associated facilities in accordance with *Directive 56*, approvals to obtain land access under the *Public Land Act,* and environmental approvals under the *Environmental and Protection Enhancement Act*.

Energy East Pipeline is being proposed and developed under the regulatory regime administered by the NEB.

United States

Natural Gas Pipelines

TransCanada's wholly owned and partially owned U.S. pipelines are considered *natural gas companies* operating under the provisions of the *Natural Gas Act of 1938* and the *Natural Gas Policy Act of 1978*, and are subject to the jurisdiction of the FERC. *The Natural Gas Act of 1938* grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation and interstate commerce. The ANR System's natural gas storage facilities in Michigan are also regulated by FERC.

Liquids Pipelines

The FERC regulates the terms and conditions of service, including transportation rates, of interstate liquids pipelines, including the U.S. portion of the Keystone Pipeline System and Cushing Marketlink. The siting and construction of pipeline facilities are regulated by the specific state commissions where the pipeline crosses. Pipeline safety is regulated by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Liquids pipelines that cross the international border between Canada and the United States, such as the proposed Upland pipeline, will require a Presidential Permit from the DOS.

Mexico

Natural Gas Pipelines

TransCanada's pipelines in Mexico are regulated by the Comisión Reguladora de Energía or Energy Regulatory Commission who approve construction of new pipeline facilities and ongoing operations of the infrastructure. Our Mexican pipelines have approved tariffs, services and related rates, however, the contracts underpinning the construction and operation of the facilities are long-term negotiated fixed rate contracts. These rates are only subject to change under specific circumstances such as certain types of force majeure events or changes in law.

ENERGY BUSINESS

Our Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta.

We own, control or are developing generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our power business in the U.S. is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low-cost baseload generation, while others are essential to providing capacity to the area in which it is located.

We conduct wholesale and retail electricity marketing and trading throughout North America from our offices in Alberta, Ontario and Massachusetts to actively manage our commodity exposure and provide higher returns.

We own or control unregulated natural gas storage capacity in Alberta and regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment).

We are the operator of all of our Energy assets, except for the Sheerness, Sundance A and Sundance B PPAs, Cartier Wind, Bruce and Portlands Energy.

Generating capacity (MW)		Type of fuel	Description	Location	Ownership
Canadian Power 8,571 MW of power generation capacity (including facilities under construction)					
Western Power 2,609 MW of power supply in Alberta and the western U.S.					
Bear Creek	80	natural gas	Cogeneration plant	Grande Prairie, Alberta	100%
Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
Coolidge	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
Sheerness PPA	756	coal	Output contracted under PPA	Hanna, Alberta	100%
Sundance A PPA	560	coal	Output contracted under PPA	Wabamun, Alberta	100%
Sundance B PPA (Owned by ASTC Power Partnership[1])	353[2]	coal	Output contracted under PPA	Wabamun, Alberta	50%
Eastern Power 2,939 MW of power generation capacity (including facilities under construction)					
Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
Cartier Wind	365[2]	wind	Five wind power projects	Gaspésie, Québec	62%
Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
Portlands Energy	275[2]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
Ontario Solar	76	solar	Eight solar facilities	Southern Ontario and New Liskeard, Ontario	100%
Bruce Power 3,023 MW of power generation capacity					
Bruce Power	3,023[2]	nuclear	Eight operating reactors	Tiverton, Ontario	48.5%

Generating capacity (MW)	Type of fuel	Description	Location	Ownership
U.S. Power 4,533 MW of power generation capacity				
Kibby Wind 132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
Ocean State Power 560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
Ravenswood 2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
TC Hydro 583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
Ironwood[3] 778	natural gas	Combined-cycle plant	Lebanon, Pennsylvania	100%
Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
CrossAlta 68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
Edson 50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
Under construction				
Napanee 900	natural gas	Combined-cycle plant	Greater Napanee, Ontario	100%

1 We have a 50 per cent interest in ASTC Power Partnership, which has a PPA for production from the Sundance B power generating facilities.
2 Our share of power generation capacity.
3 Acquired February 1, 2016.

We own or have the rights to power supply in Alberta and Arizona through three long-term PPAs, four natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

	Type of contract	With	Expires
Sheerness PPA	Power purchased under a 20-year PPA	ATCO Power and TransAlta Utilities Corporation	2020
Sundance A PPA	Power purchased under a 20-year PPA	TransAlta Utilities Corporation	2017
Sundance B PPA	Power purchased under a 20-year PPA (own 50 per cent through the ASTC Power Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

	Type of contract	With	Expires
Coolidge	Power sold under a 20-year PPA	Salt River Project Agricultural Improvements & Power District	2031

We own or are developing power generation capacity in eastern Canada. All of the power produced by these assets is sold under long-term contracts.

Assets currently operating under long-term contracts are as follows:

	Type of contract	With	Expires
Bécancour[1,2]	20-year PPA and tolling agreement Steam sold to an industrial customer	Hydro-Québec	2036
Cartier Wind	20-year PPA	Hydro-Québec	2026-2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2024
Halton Hills	20-year Clean Energy Supply contract	IESO	2030
Portlands Energy	20-year Clean Energy Supply contract	IESO	2029
Ontario Solar[3]	20-year FIT contracts	IESO	2032-2034

1 Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.

2 In August 2015, we executed an agreement with Hydro-Québec to amend Bécancour's electricity supply contract. The amendment allows HQ to dispatch up to 570 MW of firm peak winter capacity from the Bécancour facility for a term of 20 years commencing in December 2016. Annual tolling payments received for this new service will be incremental to existing capacity payments earned under the agreement and will expire in 2036. The existing capacity payments terminate in 2026.

3 We acquired four facilities in 2013 and an additional four facilities in 2014.

Assets currently under construction are as follows:

	Type of contract	With	Expires
Napanee[1]	20-year Clean Energy Supply contract	IESO	20 years from in-service date

1 Expected in-service date is between late 2017 and early 2018.

Further information about our Energy holdings and significant developments and opportunities in relation to Energy can be found in the MD&A in the *Energy – Results, Energy – Understanding the Energy business* and *Energy – Significant events* sections, which sections of the MD&A are incorporated by reference herein.

General

EMPLOYEES

At Year End, TransCanada's principal operating subsidiary, TCPL, had 5,512 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary (includes U.S. employees working in Canada)	2,800
Western Canada (excluding Calgary)	474
Eastern Canada	302
Houston (includes Canadian employees working in the U.S.)	491
U.S. Midwest	439
U.S. Northeast	424
U.S. Southeast/Gulf Coast (excluding Houston)	326
U.S. West Coast	74
Mexico and South America	182
Total	**5,512**

CORPORATE RESTRUCTURING AND BUSINESS TRANSFORMATION

In mid-2015, we commenced a business restructuring and transformation initiative. While there is no change to our corporate strategy, we have undertaken this initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations. For more information about our corporate restructuring and business transformation, refer to the*Corporate – Significant events* section of the MD&A, which section of the MD&A is incorporated by reference herein.

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Health, Safety and Environment committee of TransCanada's Board of Directors (the**Board**) oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our HSE corporate policy through regular reporting from management. We have an integrated HSE management system that establishes a framework for managing HSE issues that is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system for HSE is modeled after international standards, conforms to external industry standards and voluntary programs, and complies with applicable legislative requirements and other internal management systems. It follows a continuous improvement cycle organized into four key areas:

- *Planning*: risk and regulatory assessment, objectives and targets, and structure and responsibility
- *Implementing*: development and implementation of programs, plans, procedures and practices aimed at operational risk management
- *Reporting*: document and records management, communication and reporting, and
- *Action*: ongoing audit and review of HSE performance.

The committee reviews HSE performance including risk management at least three times a year. It receives detailed reports on:

- overall HSE corporate governance and performance
- operational performance and preventive maintenance metrics
- asset integrity programs
- security and emergency preparedness, incident response and evaluation
- people and process safety performance metrics, and
- developments in and compliance with applicable legislation and regulations.

The committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans emanating from internal and third party audits.

Information about the financial and operational effects of environmental protection requirements on the capital expenditures, profit or loss and competitive position of TransCanada can be found in the MD&A in the *Other information – Risks and risk management – Health, safety and environment* section, which section of the MD&A is incorporated by reference herein.

Environmental policies

TransCanada's facilities are subject to federal, state, provincial, and local environmental statutes and regulations governing environmental protection, including, but not limited to, air emissions and GHG emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements and/or the issuance of orders respecting future operations. We have implemented audit and inspection programs designed to ensure our facilities remain in compliance with environmental requirements.

Safety and asset integrity

As one of TransCanada's priorities, safety is an integral part of the way our employees work. Each year we develop goals predicated on achieving year over year sustainable improvement in our safety performance, and meeting or exceeding industry benchmarks.

The safety and integrity of our existing and newly developed infrastructure is a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied.

TransCanada annually conducts emergency response exercises to practice effective coordination between the Company, local emergency responders, regulatory agencies and government officials in the event of an emergency. TransCanada uses the Incident Command System which supports a unified approach to emergency response with these community members. TransCanada also provides annual training to all field staff in the form of table top exercises, online and vendor lead training.

Social Policies

TransCanada has a number of policies, guiding principles and practices in place to help manage Indigenous and stakeholder relations. We have adopted a Code of business ethics (**Code**) which applies to all employees, officers and directors as well as contract workers of TransCanada and its wholly-owned subsidiaries and operated entities in countries where we conduct business. All employees (including executive officers) and directors must certify their compliance with the Code every year. The Code is based on the Company's four core values of integrity, collaboration, responsibility and innovation, which guide the interaction between and among the Company's employees and contractors, and serve as a standard for us in our dealings with all stakeholders.

Our approach to Indigenous and stakeholder engagement is based on building relationships, mutual respect and trust while recognizing the unique values, needs and interests of each community. Our stakeholder relations framework provides the structure to guide our teams' behavior and actions, so they understand their responsibility and extend respect, courtesy and the opportunity to respond to every stakeholder.

TransCanada also has an Avoiding bribery and corruption program which includes an Avoiding bribery and corruption policy, annual online training provided to all personnel, face to face training provided to personnel in higher risk areas of our business, a supplier and contractor due diligence review process, and auditing of certain types of transactions.

We strive for continuous improvement in how we navigate the interconnections and complexity of environmental, social and economic issues related to our business. These issues are of great importance to our stakeholders, and have an impact on our ability to build and operate energy infrastructure.

Risk factors

A discussion of our risk factors can be found in the MD&A in the *Natural Gas Pipelines – Business risks, Liquids Pipelines – Business risks, Energy – Business risks* and *Other information – Risks and risk management* sections, which sections of the MD&A are incorporated by reference into this AIF.

Dividends

Our Board has not adopted a formal dividend policy. The Board reviews the financial performance of TransCanada quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, our payment of dividends is primarily funded from dividends TransCanada receives as the sole common shareholder of TCPL. Provisions of various trust indentures and credit arrangements to which TCPL is a party restrict TCPL's ability to declare and pay dividends to TransCanada under certain circumstances and, if such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends. Pursuant to the terms of the trust notes issued by TransCanada Trust (a financing trust subsidiary wholly owned by TCPL) and related agreements, in certain circumstances including where holders of the trust notes receive deferral preferred shares of TCPL in lieu of cash interest payments and where exchange preferred shares are issued to holders of the trust notes as a result of certain bankruptcy related events, TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all such exchange or deferral preferred shares are redeemed by TCPL. Further information about such trust notes can be found in the *Financial condition – Junior subordinated notes issued* section of the MD&A. In the opinion of TransCanada's management, such provisions do not currently restrict or alter TransCanada's ability to declare or pay dividends.

Dividends on our preferred shares are payable quarterly, as and when declared by the Board. The dividends declared on our common and preferred shares during the past three completed financial years are set out in the following table:

	2015	2014	2013
Dividends declared on common shares	$2.08	$1.92	$1.84
Dividends declared on Series 1 preferred shares	$0.82	$1.15	$1.15
Dividends declared on Series 2 preferred shares[1]	$0.63	—	—
Dividends declared on Series 3 preferred shares	$0.77	$1.00	$1.00
Dividends declared on Series 4 preferred shares[2]	$0.23	—	—
Dividends declared on Series 5 preferred shares	$1.10	$1.10	$1.10
Dividends declared on Series 7 preferred shares[3]	$1.00	$1.00	$0.91
Dividends declared on Series 9 preferred shares[4]	$1.06	$1.09	—
Dividends declared on Series 11 preferred shares[5]	$0.70	—	—

1 Issued December 31, 2014 following conversion of Series 1 preferred shares at the election of the holders.
2 Issued June 30, 2015 following conversion of Series 3 preferred shares at the election of the holders.
3 Issued March 4, 2013.
4 Issued January 20, 2014.
5 Issued March 2, 2015.

We increased the quarterly dividend on our outstanding common shares by nine per cent to $0.565 per share for the quarter ending March 31, 2016.

Description of capital structure

SHARE CAPITAL

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 702,614,096were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which the following were issued and outstanding as at Year End, or as otherwise indicated below.

First preferred shares	Issued and outstanding	Convertible to
Series 1 preferred shares	9,498,423	Series 2 preferred shares
Series 2 preferred shares[1]	12,501,577	Series 1 preferred shares
Series 3 preferred shares	8,533,405	Series 4 preferred shares
Series 4 preferred shares[2]	5,466,595	Series 3 preferred shares
Series 5 preferred shares[3]	12,714,261	Series 6 preferred shares
Series 6 preferred shares	1,285,739	Series 5 preferred shares
Series 7 preferred shares	24,000,000	Series 8 preferred shares
Series 9 preferred shares[4]	18,000,000	Series 10 preferred shares
Series 11 preferred shares[5]	10,000,000	Series 12 preferred shares

1 Issued upon conversion of Series 1 preferred shares on December 31, 2014.
2 Issued upon conversion of Series 3 preferred shares on June 30, 2015.
3 Issued upon conversion of Series 5 preferred shares on February 1, 2016.
4 Issued January 20, 2014.
5 Issued March 2, 2015.

The following is a description of the material characteristics of each of these classes of shares.

Common shares

The common shares entitle the holders thereof to one vote per share at all meetings of shareholders, except meetings at which only holders of another specified class of shares are entitled to vote, and, subject to the rights, privileges, restrictions and conditions attaching to the first preferred shares and the second preferred shares, whether as a class or a series, and to any other class or series of shares of TransCanada which rank prior to the common shares, entitle the holders thereof to receive (i) dividends if, as and when declared by the Board out of the assets of TransCanada properly applicable to the payment of the dividends in such amount and payable at such times and at such place or places as the Board may from time to time determine, and (ii) the remaining property of TransCanada upon a dissolution.

We have a shareholder rights plan that is designed to ensure, to the extent possible, that all shareholders of TransCanada are treated fairly in connection with any take-over bid for the Company. The plan creates a right attaching to each common share outstanding and to each common share subsequently issued. Each right becomes exercisable ten trading days after a person has acquired (**an acquiring person**), or commences a take-over bid to acquire, 20 per cent or more of the common shares, other than by an acquisition pursuant to a take-over bid permitted under the terms of the plan (**a permitted bid**). Prior to a flip-in event (as described below), each right permits registered holders to purchase from the Company common shares of TransCanada at an exercise price equal to three times the market price of such shares, subject to adjustments and anti-dilution provisions (**the exercise price**). The beneficial acquisition by any person of 20 per cent or more of the common shares, other than by way of permitted bid, is referred to as a *flip-in event*. Ten trading days after a flip-in event, each right will permit registered holders other than an acquiring person to receive, upon payment of the exercise price, the number of common shares with an aggregate market price equal to twice the exercise price.

TransCanada has a dividend reinvestment and share purchase plan (**DRP**) which permits eligible holders of TransCanada common or preferred shares to elect to reinvest their dividends and make optional cash payments to buy TransCanada common shares acquired on the open market at 100 per cent of the weighted average purchase price. Participants may also make additional cash payments of up to $10,000 per quarter to purchase additional common shares, which optional purchases are not eligible for any discount on the price of common shares. Participants are not responsible for payment of brokerage commissions or other transaction expenses for purchases made pursuant to the DRP.

TransCanada also has a stock based compensation plan that allows some employees to purchase common shares of TransCanada. Option exercise prices are equal to the closing price on the Toronto Stock Exchange (**TSX**) on the last trading day immediately preceding the grant date. Options granted under the plan are generally fully exercisable after three years and expire seven years after the date of grant.

First preferred shares

Subject to certain limitations, the Board may, from time to time, issue first preferred shares in one or more series and determine for any such series, its designation, number of shares and respective rights, privileges, restrictions and conditions. The first preferred shares as a class have, among others, the provisions described below.

The first preferred shares of each series rank on a parity with the first preferred shares of every other series, and are entitled to preference over the common shares, the second preferred shares and any other shares ranking junior to the first preferred shares with respect to the payment of dividends, the repayment of capital and the distribution of assets of TransCanada in the event of its liquidation, dissolution or winding up.

Except as provided by the CBCA, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the directors if TransCanada fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the approval of the holders of the first preferred shares as a class. Any such approval to be given by the holders of the first preferred shares may be given by the affirmative vote of the holders of not less than sixty-six and two thirds per cent of the first preferred shares represented and voted at a meeting or adjourned meeting of such holders.

The holders of Series 1, 3, 5, 7, 9 and 11 preferred shares will be entitled to receive quarterly fixed rate cumulative preferential cash dividends, as and when declared by the Board, to be reset periodically on established dates to an annualized rate equal to the sum of the then five-year Government of Canada bond yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below and have the right to convert their shares into cumulative redeemable Series 2, 4, 6, 8, 10 and 12 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 1, 3, 5, 7, 9 and 11 preferred shares are redeemable by TransCanada in whole or in part on such redemption dates as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon.

The holders of Series 2, 4, 6, 8, 10 and 12 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series 1, 3, 5, 7, 9 and 11 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 2, 4, 6, 8, 10 and 12 preferred shares are redeemable by TransCanada in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11 and 12 preferred shares shall be entitled to receive $25.00 per preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the first preferred shares.

Series of first preferred shares	Initial redemption date	Redemption/conversion dates
Series 1 preferred shares	—	December 31, 2019 and every fifth year thereafter
Series 2 preferred shares	December 31, 2014	December 31, 2019 and every fifth year thereafter
Series 3 preferred shares	—	June 30, 2020 and every fifth year thereafter
Series 4 preferred shares	June 30, 2015	June 30, 2020 and every fifth year thereafter
Series 5 preferred shares	—	January 30, 2016 and every fifth year thereafter
Series 6 preferred shares	January 30, 2016	January 30, 2021 and every fifth year thereafter
Series 7 preferred shares	—	April 30, 2019 and every fifth year thereafter
Series 8 preferred shares	April 30, 2019	April 30, 2024 and every fifth year thereafter
Series 9 preferred shares	—	October 30, 2019 and every fifth year thereafter
Series 10 preferred shares	October 30, 2019	October 30, 2024 and every fifth year thereafter
Series 11 preferred shares	—	November 30, 2020 and every fifth year thereafter
Series 12 preferred shares	November 30, 2020	November 30, 2025 and every fifth year thereafter

Except as provided by the CBCA, the respective holders of the first preferred shares of each outstanding series are not entitled to receive notice of, attend at, or vote at any meeting of shareholders unless and until TransCanada shall have failed to pay eight quarterly dividends on such series of preferred shares, whether or not consecutive, in which case the holders of the first preferred shares of such series shall have the right to receive notice of and to attend each meeting of shareholders at which directors are to be elected and which take place more than 60 days after the date on which the failure first occurs, and to one vote with respect to resolutions to elect directors for each of the first preferred share of such series, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the first preferred shares may be amended with the written approval of all the holders of such series of shares outstanding or by at least two thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Second preferred shares

The rights, privileges, restrictions and conditions attaching to the second preferred shares are substantially identical to those attaching to the first preferred shares, except that the second preferred shares are junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Credit ratings

Although TransCanada Corporation has not issued debt to the public, it has been assigned credit ratings by Moody's Investors Service, Inc. (**Moody's**) and Standard & Poor's (**S&P**) and its outstanding preferred shares have also been assigned credit ratings by Moody's, S&P and DBRS Limited (**DBRS**). Moody's has assigned an issuer rating of Baa1 with a stable outlook and S&P has assigned a long-term corporate credit rating of A- with a stable outlook. TransCanada Corporation does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL and TransCanada Trust, our 100 per cent owned financing trust subsidiary of TCPL. The following table sets out the current credit ratings assigned to those outstanding classes of securities of the Company, TCPL and TransCanada Trust which have been rated by DBRS, Moody's and S&P:

	DBRS	Moody's	S&P
Senior unsecured debt			
Debentures	A (low)	A3	A-
Medium-term notes	A (low)	A3	A-
Junior subordinated notes	BBB	Baa1	BBB
TransCanada Trust-Subordinated Notes	Not rated	Baa2	BBB
Preferred shares	Pfd-2 (low)	Baa2	P-2
Commercial paper	R-1 (low)	P-2	A-2
Trend/rating outlook	Stable	Stable	Stable

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Each of the Company and TCPL paid fees to each of DBRS, Moody's and S&P for the credit ratings rendered in respect of their outstanding classes of securities noted above. Other than annual monitoring fees for the Company and TCPL and their rated securities, no additional payments were made to DBRS, Moody's and S&P in respect of any other services provided to us during the past two years.

The information concerning our credit ratings relates to our financing costs, liquidity and operations. The availability of our funding options may be affected by certain factors, including the global capital market environment and outlook as well as our financial performance. Our access to capital markets at competitive rates is dependent on our credit rating and rating outlook, as determined by credit rating agencies such as DBRS, Moody's and S&P, and if our ratings were downgraded TransCanada's financing costs and future debt issuances could be unfavorably impacted. A description of the rating agencies' credit ratings listed in the table above is set out below.

DBRS

DBRS has different rating scales for short- and long-term debt and preferred shares. *High* or *low* grades are used to indicate the relative standing within all rating categories other than AAA and D and other than in respect of DBRS' ratings of commercial paper and short-term debt, which utilize *high, middle* and *low* subcategories for its R-1 and R-2 rating categories. In respect of long-term debt and preferred share ratings, the absence of either a *high* or *low* designation indicates the rating is in the middle of the category. The R-1 (low) rating assigned to TCPL's short-term debt is in the third highest of ten rating categories and indicates good credit quality. The capacity for payment of short-term financial obligations as they fall due is substantial. The overall strength is not as favourable as higher rating categories. Short-term debt rated R-1 (low) may be vulnerable to future events, but qualifying negative factors are considered manageable. The A (low) rating assigned to TCPL's senior unsecured debt is in the third highest of ten categories for long-term debt. Long-term debt rated A is good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than that of AA rated securities. Long-term debt rated A may be vulnerable to future events but qualifying negative factors are considered manageable. The BBB rating assigned to junior subordinated notes is in the fourth highest of the ten categories for long-term debt. Long-term debt rated BBB is of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but long-term debt rated BBB may be vulnerable to future events. The Pfd-2 (low) rating assigned to TransCanada's preferred shares is in the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial; however, earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. In general, Pfd-2 ratings correspond with companies whose long-term debt is rated in the A category.

MOODY'S

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are appended to each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and a modifier 3 indicates a ranking in the lower end of that generic rating category. The A3 rating assigned to TCPL's senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are judged to be upper medium-grade and are subject to low credit risk. The P-2 rating assigned to TCPL's U.S. commercial paper program is the second highest of four rating categories for short-term debt issuers. Issuers rated P-2 have a strong ability to repay short-term debt obligations. The Baa1 and Baa2 ratings assigned to TCPL's junior subordinated notes and to both TransCanada's preferred shares and the trust notes, respectively, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated debt ranking higher within the Baa rating category with a modifier of 1 as opposed to the modifier of 2 on the preferred shares. Obligations rated Baa are judged to be medium-grade and are subject to moderate credit risk and, as such, may possess certain speculative characteristics.

S&P

S&P has different rating scales for short- and long-term obligations. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The A- rating assigned to TCPL's senior unsecured debt is in the third highest of ten rating categories for long-term obligations. An A rating indicates the obligor's capacity to meet its financial commitment is strong; however, the obligation is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. TCPL's U.S. commercial paper program is rated A-2 which is the second highest of eight rating categories for short-term debt issuers. Short-term debt issuers rated A-2 have satisfactory capacity to meet their financial commitments, however they are somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the highest rating category. The BBB rating assigned to TCPL's junior subordinated notes and to the trust notes is in the fourth highest of ten rating categories for long-term debt obligations and the P-2 rating assigned to TransCanada's preferred shares is the second highest of eight rating categories for Canadian preferred shares. The BBB and P-2 ratings assigned to TCPL's junior subordinated notes, the trust notes and TransCanada's preferred shares exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

Market for securities

TransCanada's common shares are listed on the TSX and the New York Stock Exchange (**NYSE**) under the symbol TRP. Our Series 1, 2, 3, 4, 5, 6, 7, 9 and 11 preferred shares have been listed for trading on the TSX since September 30, 2009, December 31, 2014, March 11, 2010, June 30, 2015, June 29, 2010, February 1, 2016, March 4, 2013, January 20, 2014 and March 2, 2015 under the symbols TRP.PR.A, TRP.PR.F, TRP.PR.B, TRP.PR.H, TRP.PR.C, TRP.PR.I, TRP.PR.D, TRP.PR.E, and TRP.PR.G respectively.

The following tables set out the reported monthly high, low, and month end closing trading prices and monthly trading volumes of the common shares of TransCanada on the TSX and the NYSE, and the respective Series 1, 2, 3, 4, 5, 7, 9 and 11 preferred shares on the TSX, for the periods indicated:

COMMON SHARES

	TSX (TRP)				NYSE (TRP)			
Month	High ($)	Low ($)	Close ($)	Volume traded	High (US$)	Low (US$)	Close (US$)	Volume traded
December 2015	$48.44	$40.58	$45.19	57,859,047	$35.17	$29.89	$32.59	34,563,571
November 2015	$45.54	$40.68	$42.14	32,389,719	$34.59	$30.48	$31.59	21,251,858
October 2015	$46.43	$41.67	$44.00	34,162,593	$35.57	$31.43	$33.59	22,296,637
September 2015	$45.84	$41.10	$42.20	34,144,320	$34.61	$30.60	$31.58	22,375,140
August 2015	$51.13	$41.95	$45.90	27,618,517	$38.92	$31.63	$34.62	22,366,364
July 2015	$52.16	$48.46	$50.83	22,653,037	$40.78	$37.22	$38.91	21,681,363
June 2015	$54.35	$50.15	$50.76	37,765,436	$43.78	$40.33	$40.62	23,904,092
May 2015	$56.64	$52.98	$53.90	19,687,840	$46.87	$42.96	$43.37	14,462,998
April 2015	$58.12	$53.57	$56.00	22,163,117	$48.10	$42.37	$46.52	19,510,057
March 2015	$56.51	$53.06	$54.16	27,402,084	$45.13	$41.51	$42.72	20,254,343
February 2015	$59.50	$53.69	$54.79	25,994,936	$48.08	$42.89	$43.83	23,970,762
January 2015	$58.17	$50.51	$56.54	30,794,015	$49.64	$42.11	$44.48	24,963,807

PREFERRED SHARES

	Preferred Shares							
Month	Series 1	Series 2	Series 3	Series 4	Series 5	Series 7	Series 9	Series 11
December 2015								
High	$17.29	$14.00	$12.59	$11.01	$12.75	$19.23	$20.10	$20.93
Low	$14.02	$12.50	$10.51	$9.65	$11.10	$16.76	$17.60	$18.10
Close	$16.64	$13.65	$12.49	$10.50	$12.75	$19.17	$19.76	$20.91
Volume traded	412,602	367,180	304,024	167,474	493,574	1,080,469	554,566	368,458
November 2015								
High	$17.59	$15.50	$13.98	$12.20	$14.99	$20.84	$21.68	$22.48
Low	$15.42	$13.68	$11.64	$10.30	$12.53	$18.04	$18.80	$20.00
Close	$15.76	$13.90	$11.96	$10.82	$12.69	$18.58	$19.35	$20.38
Volume traded	400,301	301,818	91,906	116,264	371,781	603,568	467,963	230,890
October 2015								
High	$16.19	$14.90	$13.19	$11.70	$13.99	$19.40	$19.80	$22.35
Low	$14.00	$12.30	$10.95	$10.09	$11.30	$15.69	$16.21	$17.58
Close	$15.60	$14.45	$13.19	$11.44	$13.35	$19.00	$19.50	$21.90
Volume traded	336,444	212,163	291,286	145,129	309,549	983,326	536,722	256,228
September 2015								
High	$17.77	$15.25	$12.99	$11.88	$13.68	$20.19	$20.46	$22.82
Low	$14.52	$12.52	$11.62	$10.75	$11.90	$16.52	$17.07	$19.04
Close	$14.98	$12.96	$11.84	$10.77	$12.20	$17.20	$17.95	$19.48
Volume traded	155,532	197,910	122,321	198,808	250,710	350,929	516,358	127,079

	Preferred Shares							
Month	**Series 1**	**Series 2**	**Series 3**	**Series 4**	**Series 5**	**Series 7**	**Series 9**	**Series 11**
August 2015								
High	$18.60	$17.16	$14.56	$15.44	$14.82	$21.10	$21.20	$23.95
Low	$13.76	$12.01	$10.76	$10.06	$10.86	$18.42	$18.82	$18.47
Close	$16.58	$14.35	$12.12	$11.00	$13.09	$18.85	$19.56	$21.80
Volume traded	110,168	117,588	140,297	71,030	175,873	344,727	247,723	127,788
July 2015								
High	$20.57	$18.85	$15.34	$15.74	$16.40	$22.25	$22.99	$25.10
Low	$18.52	$16.98	$14.50	$14.20	$14.75	$20.24	$21.04	$23.36
Close	$18.62	$17.08	$14.65	$15.42	$14.83	$20.24	$21.04	$23.67
Volume traded	204,317	125,457	650,505	156,284	642,077	593,175	147,663	312,258
June 2015								
High	$20.71	$19.25	$15.26	—	$17.23	$23.01	$23.89	$25.24
Low	$19.27	$18.55	$14.50	—	$15.90	$21.79	$22.29	$24.52
Close	$20.41	$18.66	$14.90	—	$16.35	$22.20	$22.69	$25.00
Volume traded	227,669	158,772	287,200	—	237,532	352,000	246,365	259,105
May 2015								
High	$21.49	$19.52	$16.76	—	$18.74	$24.47	$24.87	$25.77
Low	$20.09	$18.62	$15.15	—	$16.74	$22.83	$23.71	$24.75
Close	$20.10	$19.25	$15.25	—	$16.96	$22.95	$23.95	$24.90
Volume traded	400,393	261,019	440,791	—	492,933	295,895	234,005	421,987
April 2015								
High	$20.85	$19.70	$15.35	—	$17.68	$23.82	$24.39	$25.08
Low	$18.60	$18.00	$13.47	—	$15.35	$21.88	$22.22	$24.60
Close	$20.63	$19.00	$15.35	—	$17.45	$23.70	$24.34	$25.06
Volume traded	202,551	286,756	751,232	—	593,653	409,397	312,264	820,359
March 2015								
High	$21.02	$20.00	$15.50	—	$18.12	$24.45	$25.03	$25.10
Low	$19.51	$18.50	$14.06	—	$16.15	$23.45	$24.00	$24.65
Close	$20.71	$19.54	$15.03	—	$16.22	$23.75	$24.32	$24.98
Volume traded	252,192	125,953	593,528	—	471,348	473,362	564,382	2,612,855
February 2015								
High	$20.83	$19.20	$15.62	—	$17.55	$24.45	$24.99	—
Low	$19.43	$17.81	$14.05	—	$16.25	$23.40	$23.43	—
Close	$20.06	$18.60	$14.17	—	$16.98	$23.88	$24.50	—
Volume traded	131,566	199,742	285,782	—	292,579	246,679	131,828	—
January 2015								
High	$21.19	$22.53	$18.66	—	$21.57	$25.30	$25.65	—
Low	$20.00	$18.65	$14.63	—	$16.75	$23.23	$23.30	—
Close	$20.66	$19.19	$15.05	—	$17.55	$23.75	$23.76	—
Volume traded	560,629	347,926	560,874	—	188,280	280,661	140,342	—

Directors and officers

As of February 10, 2016, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 540,961 common shares of TransCanada. This constitutes less than one per cent of TransCanada's common shares. The Company collects this information from our directors and officers but otherwise we have no direct knowledge of individual holdings of TransCanada's securities.

DIRECTORS

The following table sets forth the names of the directors who serve on the Board, as of February 10, 2016 (unless otherwise indicated), together with their jurisdictions of residence, all positions and offices held by them with TransCanada, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the Arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Kevin E. Benson Calgary, Alberta Canada	Corporate director. Director, Calgary Airport Authority from January 2010 to December 2013.	2005
Derek H. Burney[1], O.C. Ottawa, Ontario Canada	Senior strategic advisor, Norton Rose Fulbright (law firm). Chair, Garda World International's (risk management and security services) Advisory Board since April 2008. Advisory Board member, Paradigm Capital Inc. (investment dealer) since May 2011. Chair, Canwest Global Communications Corp. (media and communications) from August 2006 (director since April 2005) to October 2010.	2005
The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Stein Monast L.L.P. (law firm). Director, Metro Inc. (food retail) since January 2001. Director, Royal Bank of Canada (chartered bank) from October 1991 to March 2014 and Chair, RBC Dexia Investors Trust until October 2011.	2002
Russell K. Girling[2] Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 2010. Chief Operating Officer from July 2009 to June 2010 and President, Pipelines from June 2006 to June 2010. Director, Agrium Inc. (agricultural) since May 2006.	2010
S. Barry Jackson[3] Calgary, Alberta Canada	Corporate director. Chair of the Board, TransCanada since April 2005. Director, WestJet Airlines Ltd. (airline) since February 2009 and Laricina Energy Ltd. (oil and gas, exploration and production) since December 2005. Director, Nexen Inc. (**Nexen**) (oil and gas, exploration and production) from 2001 to June 2013, Chair of the board, Nexen from 2012 to June 2013.	2002
John E. Lowe Houston, Texas U.S.A.	Chairman of the Board of Directors, Apache Corporation (**Apache**) (oil and gas) since May 2015. Senior Adviser at Tudor Pickering, Holt & Co. LLC (energy investment and merchant banking) since September 2012. Director, Phillips 66 Company (energy infrastructure) since May 2012. Director, Apache from July 2013 to May 2015. Director, Agrium Inc. (agriculture) from May 2010 to August 2015. Director, DCP Midstream LLC and DCP Midstream GP, LLC (energy infrastructure) from October 2008 to April 2012. Director, Chevron Phillips Chemical Co. LLC (global petrochemicals) from October 2008 to January 2011.	2015
Paula Rosput Reynolds Seattle, Washington U.S.A.	President and Chief Executive Officer, PreferWest, LLC (business advisory group) since October 2009. Director, BP p.l.c. (oil and gas) since May 2015. Director, BAE Systems plc. (aerospace, defence, information security) since April 2011. Director, Delta Air Lines, Inc. (airline) from August 2004 to June 2015. Director, Anadarko Petroleum Corporation (oil and gas, exploration and production) from August 2007 to May 2014.	2011
John Richels Nichols Hills, Oklahoma U.S.A.	Corporate Director. Vice Chair, Devon Energy Corporation (**Devon**) (oil and gas, exploration and production, energy infrastructure) since December 2014 and Director since June 2007. Chairman of EnLink Midstream, LLC and EnLink Midstream Partner, LP (energy infrastructure) since March 2014. Director, BOK Financial Corporation (financial services) since January 2013. Chairman, American Exploration and Production Council since May 2012. Former Vice-Chairman of the board of governors, Association of Petroleum Producers.	2013
Mary Pat Salomone[4] Naples, Florida U.S.A.	Corporate director. Director, Intertape Polymer Group (manufacturing) since November 2015. Senior Vice-President and Chief Operating Officer, The Babcock & Wilcox Company (**B&W**) (energy infrastructure) from January 2010 to June 2013. Director, United States Enrichment Corporation (basic materials, nuclear) from December 2011 to October 2012.	2013
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Pengrowth Energy Corporation (oil and gas, exploration and production) since December 2010. Director, and Audit and Governance committee Chair, Canadian Energy Services & Technology Corp. (chemical, oilfield services) since January 2010. Director, Northpoint Resources Ltd. (oil and gas, exploration and production) from July 2013 to February 2015. Director, C&C Energia Ltd. (oil and gas) from May 2010 to December 2012.	2006
Siim A. Vanaselja Westmount, Québec Canada	Corporate Director. Director, Great-West Lifeco Inc. since May 2014. Director and Audit committee Chair, Maple Leaf Sports and Entertainment Ltd. (sports, property management) since August 2012. Executive Vice-President and Chief Financial Officer, BCE Inc. and Bell Canada (telecommunications and media) from January 2001 to June 2015.	2014
Richard E. Waugh Calgary, Alberta Canada	Corporate director. Former Deputy Chairman of the Bank of Nova Scotia (**Scotiabank**) (chartered bank) until January 2014. President and Chief Executive Officer, Scotiabank from March 2003 to November 2013. Director, Catalyst Inc. (non-profit) from February 2007 to November 2013 and Chair, Catalyst Canada Inc. Advisory Board from February 2007 to October 2013.	2012

1 Canwest Global Communications Corp. (**Canwest**) voluntarily entered into the *Companies' Creditors Arrangement Act* (**CCAA**) and obtained an order from the Ontario Superior Court of Justice (Commercial Division) to start proceedings on October 6, 2009. Although no cease trade orders were issued, Canwest shares were de-listed by the TSX after the filing and started trading on the TSX Venture Exchange. Canwest emerged from CCAA protection and Postmedia Network acquired its newspaper business on July 13, 2010 while Shaw Communications Inc. acquired its broadcast media business on October 27, 2010. Mr. Burney ceased to be a director of Canwest on October 27, 2010.

2 As President and CEO of TransCanada, Mr. Girling is not a member of any Board Committees, but is invited to attend committee meetings as required.

3 Laricina Energy (**Laricina**) voluntarily entered into the CCAA and obtained an order from the Court of Queen's Bench of Alberta, Judicial Centre of Calgary for creditor protection and stay of proceedings effective March 26, 2015. A final court order was granted on January 28, 2016, allowing the company to exit from protection under the CCAA and concluding the stay of proceedings against Laricina and its subsidiaries.

4 Ms. Salomone was a director of Crucible Materials Corp. (**Crucible**) from May 2008 to May 1, 2009. On May 6, 2009, Crucible and one of its affiliates filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware (the **Bankruptcy Court**). On August 26, 2010, the Bankruptcy Court entered an order confirming Crucible's Second Amended Chapter 11 Plan of Liquidation.

BOARD COMMITTEES

TransCanada has four committees of the Board: the Audit committee, the Governance committee, the Health, Safety & Environment committee and the Human Resources committee. The voting members of each of these committees, as of February 10, 2016, are identified below.

Director	Audit committee	Governance committee	Health, Safety & Environment committee	Human Resources committee
Kevin E. Benson	ü	ü		
Derek H. Burney	ü	ü		
Paule Gauthier			ü	ü
S. Barry Jackson (Chair)		ü		ü
John E. Lowe	ü		ü	
Paula Rosput Reynolds			ü	Chair
John Richels			ü	ü
Mary Pat Salomone	ü		ü	
D. Michael G. Stewart	ü		Chair	
Siim A. Vanaselja	Chair	ü		
Richard E. Waugh		ü		ü

Information about the Audit committee can be found in this AIF under the heading *Audit committee*.

OFFICERS

All of the executive officers and corporate officers of TransCanada reside in Calgary, Alberta, Canada. Positions and offices held with TransCanada are also held by such person at TCPL. As of the date hereof, the officers of TransCanada, their present positions within TransCanada and their principal occupations during the five preceding years are as follows:

Executive officers

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	President and Chief Executive Officer.
Kristine L. Delkus	Executive Vice-President, Stakeholder Relations and General Counsel	Prior to October 2015, Executive Vice-President, General Counsel and Chief Compliance Officer. Prior to March 2014, Senior Vice-President, Pipelines Law and Regulatory Affairs. Prior to June 2012, Deputy General Counsel, Pipelines and Regulatory Affairs since September 2006 (TCPL).
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Karl R. Johannson	Executive Vice-President and President, Natural Gas Pipelines	Prior to November 2012, Senior Vice-President, Canadian and Eastern U.S. Pipelines since January 2011.
Donald R. Marchand	Executive Vice-President, Corporate Development and Chief Financial Officer	Prior to October 2015, Executive Vice-President and Chief Financial Officer since July 2010.
Paul E. Miller	Executive Vice-President and President, Liquids Pipelines	Prior to March 2014, Senior Vice-President, Oil Pipelines.
Alexander J. Pourbaix	Chief Operating Officer	Prior to October 2015, Executive Vice-President and President, Development. Prior to March 2014, President, Energy and Oil Pipelines since July 2010.
William C. Taylor	Executive Vice-President and President, Energy	Prior to March 2014, Senior Vice-President, U.S. and Canadian Power. Prior to May 2013, Senior Vice-President, Eastern Power.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Sean M. Brett	Vice-President, Risk Management	Prior to August 2015, Vice-President and Treasurer since July 2010.
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation (TCC) since May 2003 and Vice-President, Taxation (TCPL) since April 2002.
Joel E. Hunter	Vice-President, Finance and Treasurer	Prior to August 2015, Vice-President, Finance since July 2010.
Christine R. Johnston	Vice-President, Law and Corporate Secretary	Prior to June 2014, Vice-President and Corporate Secretary. Prior to March 2012, Vice-President, Finance Law since January 2010.
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller since June 2006.

CONFLICTS OF INTEREST

Directors and officers of TransCanada and its subsidiaries are required to disclose any existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the CBCA. Our Code covers potential conflicts of interest.

Serving on other boards

The Board believes that it is important for it to be composed of qualified and knowledgeable directors. As a result, due to the specialized nature of the energy infrastructure business, some of our directors are associated with or sit on the boards of companies that ship natural gas or liquids through our pipeline systems. Transmission services on most of TransCanada's pipeline systems in Canada and the U.S. are subject to regulation and accordingly we generally cannot deny transportation services to a creditworthy shipper. The Governance committee monitors relationships among directors to ensure that business associations do not affect the Board's performance.

The Board considers whether directors serving on the boards of all entities including public and private companies, Crown corporations and other state-owned entities, and non-profit organizations pose any potential conflict. The Board reviews these relationships annually to determine that they do not interfere with any of our director's ability to act in our best interests. If a director declares a material interest in any material contract or material transaction being considered at the meeting, the director is not present during the discussion and does not vote on the matter.

Our Code requires employees to receive consent before accepting a directorship with an entity that is not an affiliate. The chief executive officer and executive vice-presidents must receive the consent of the Governance committee. All other employees must receive the consent of their immediate supervisor.

Affiliates

The Board oversees relationships between TransCanada and any affiliates to avoid any potential conflicts of interest. This includes our relationship with the TCLP, a master limited partnership listed on the NYSE.

Corporate governance

Our Board and management are committed to the highest standards of ethical conduct and corporate governance.

TransCanada is a public company listed on the TSX and the NYSE, and we recognize and respect rules and regulations in both Canada and the U.S.

Our corporate governance practices comply with the Canadian governance guidelines, which include the governance rules of the TSX and Canadian Securities Administrators:

- National Instrument 52-110, *Audit Committees*
- National Policy 58-201, *Corporate Governance Guidelines*, and
- National Instrument 58-101, *Disclosure of Corporate Governance Practices*.

We also comply with the governance listing standards of the NYSE and the governance rules of the SEC that, in each case, apply to foreign private issuers.

Our governance practices comply with the NYSE standards for U.S. companies in all significant respects, except as summarized on our website (www.transcanada.com). As a non-U.S. company, we are not required to comply with most of the governance listing standards of the NYSE. As a foreign private issuer, however, we must disclose how our governance practices differ from those followed by U.S. companies that are subject to the NYSE standards.

We benchmark our policies and procedures against major North American companies to assess our standards and we adopt best practices as appropriate. Some of our best practices are derived from the NYSE rules and comply with applicable rules adopted by the SEC to meet the requirements of the *Sarbanes-Oxley Act of 2002* and the *Dodd-Frank Wall Street Reform and Consumer Protection Act*.

Audit committee

The Audit committee is responsible for assisting the Board in overseeing the integrity of our financial statements and our compliance with legal and regulatory requirements. It is also responsible for overseeing and monitoring the internal accounting and reporting process and the process, performance and independence of our internal and external auditors. The charter of the Audit committee can be found in *Schedule B* of this AIF.

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The members of the Audit committee as of February 10, 2016 are Siim A. Vanaselja (Chair), Kevin E. Benson, Derek H. Burney, John E. Lowe, Mary Pat Salomone, and D. Michael G. Stewart.

The Board believes that the composition of the Audit committee reflects a high level of financial literacy and expertise. Each member of the Audit committee has been determined by the Board to be *independent* and *financially literate* within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Mr. Vanaselja, Mr. Benson and Mr. Lowe are *Audit Committee Financial Experts* as that term is defined under U.S. securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit committee. The following is a description of the education and experience, apart from their respective roles as directors of TransCanada, of each member of the Audit committee that is relevant to the performance of his responsibilities as a member of the Audit committee.

Siim A. Vanaselja

Mr. Vanaselja is a member of the Chartered Professional Accountants of Ontario and holds an Honours Bachelor of Business degree from the Schulich School of Business. He was the Executive Vice-President and Chief Financial Officer of BCE Inc. and Bell Canada until June 2015, having previously served as Executive Vice-President and Chief Financial Officer of Bell Canada International from 1996 to 2001. Prior to that, he was a partner at the accounting firm KPMG Canada in Toronto. Mr. Vanaselja serves as director for Great-West Lifeco Inc. and Maple Leaf Sports and Entertainment Ltd. He has served as a member of the Conference Board of Canada's National Council of Financial Executives, the Corporate Executive Board's Working Council for Chief Financial Officers and Moody's Council of Chief Financial Officers.

Kevin E. Benson

Mr. Benson is a Chartered Accountant (South Africa) and was a member of the South African Society of Chartered Accountants. He serves as a director of the Winter Sport Institute, and was the President and Chief Executive Officer of Laidlaw International, Inc. until October 2007. In prior years, he has held several executive positions including as President and Chief Executive Officer of The Insurance Corporation of British Columbia and has served on other public company boards and on the audit committees of certain of those boards.

Derek H. Burney

Mr. Burney earned a Bachelor of Arts (Honours) and Master of Arts from Queen's University. He is currently a senior advisor at Norton Rose Fulbright. He previously served as President and Chief Executive Officer of CAE Inc. and as Chair and Chief Executive Officer of Bell Canada International Inc. Mr. Burney was the lead director at Shell Canada Limited until May 2007 and was the Chair of Canwest Global Communications Corp. until October 2010. He has served on one other organization's audit committee and has participated in Financial Reporting Standards Training offered by KPMG.

John E. Lowe

Mr. Lowe holds a Bachelor of Science degree in Finance and Accounting from Pittsburg State University and is a Certified Public Accountant (inactive). He has been the non-executive Chairman of Apache Corporation's board of directors since May 2015. He also currently serves on the board of directors for Phillips 66 Company and has been the Senior Executive Adviser at Tudor, Pickering, Holt & Co. LLC since September 2012. Mr. Lowe has previously served on the audit committees for Agrium Inc. and DCP Midstream LLC. He has also held various executive and management positions with ConocoPhillps for more than 25 years.

Mary Pat Salomone

Ms. Salomone has a Bachelor of Engineering in Civil Engineering from Youngstown State University and a Master of Business Administration from Baldwin Wallace College. She completed the Advanced Management Program at Duke University's Fuqua School of Buiness in 2011. Ms. Salomone was the Senior Vice-President and Chief Operating Officer of B&W until June 2013. She previously held a number of senior roles with B&W Nuclear, including serving as the Manager of Business Development from 2009 to 2010 and Manager of Strategic Acquisitions from 2008 to 2009. She also served as President and Chief Executive Officer of Marine Mechanical Corporation from 2001 through 2007, which B&W acquired in 2007.

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science in Geological Sciences with First Class Honours from Queen's University. He currently serves on the board of directors of Pengrowth Energy Corporation (compensation committee Chair) and Canadian Energy Services and Technology Corp. (audit committee Chair). He has also previously served on the board of directors of several other public companies and organizations and was on the audit committee of certain of those boards. Mr. Stewart held a number of senior executive positions with Westcoast Energy Inc. including Executive Vice-President, Business Development. He has also been active in the Canadian energy industry for over 40 years.

PRE-APPROVAL POLICIES AND PROCEDURES

TransCanada's Audit committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit committee has granted pre-approval for specified non-audit services. For engagements of up to $250,000, approval of the Audit committee Chair is required, and the Audit committee is to be informed of the engagement at the next scheduled Audit committee meeting. For all engagements of $250,000 or more, pre-approval of the Audit committee is required. In all cases, regardless of the dollar amount involved, where there is a potential for conflict of interest involving the external auditor to arise on an engagement, the Audit committee must pre-approve the assignment.

To date, all non-audit services have been pre-approved by the Audit committee in accordance with the pre-approval policy described above.

EXTERNAL AUDITOR SERVICE FEES

The table below shows the services KPMG provided during the last two fiscal years and the fees we paid them:

($ millions)	2015	2014
Audit fees	$7.8	$6.4
• audit of the annual consolidated financial statements		
• services related to statutory and regulatory filings or engagements		
• review of interim consolidated financial statements and information contained in various prospectuses and other securities offering documents		
Audit-related fees	$0.2	$0.2
• services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment plans		
Tax fees	$0.5	$0.5
• Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees	—	—
Total fees	**$8.5**	**$7.1**

Legal proceedings and regulatory actions

Legal proceedings, arbitrations and regulatory actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position, results of operations or liquidity. We are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position, results of operations or liquidity.

On January 6, 2016, TransCanada filed a Notice of Intent to initiate a claim under Chapter 11 of NAFTA in response to the denial of the U.S. Presidential permit for the Keystone XL Pipeline. Through the NAFTA claim, the Company is seeking to recover more than US$15 billion in costs and damages that it estimates it has suffered as a result of the U.S. Administration's breach of its NAFTA obligations. This litigation is in a preliminary stage and the likelihood of success and resulting impact on the Company's financial position or results of operations is unknown at this time.

Further information about the Keystone XL Pipeline claims can be found in this AIF under the heading *Developments in the Liquids Pipelines business* and in the MD&A under the heading *Liquids Pipelines – Understanding the Liquids Pipelines business* and *Liquids Pipelines – Significant events*.

Transfer agent and registrar

TransCanada's transfer agent and registrar is Computershare Trust Company of Canada with its Canadian transfer facilities in the cities of Vancouver, Calgary, Toronto, Halifax and Montréal.

Material contracts

TransCanada did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2015, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2015 which are still in effect as at the date of this AIF.

Interest of experts

KPMG LLP are the auditors of TransCanada and have confirmed that they are independent with respect to TransCanada within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to all relevant U.S. professional and regulatory standards.

Additional information

1. Additional information in relation to TransCanada may be found under TransCanada's profile on SEDAR (www.sedar.com).
2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TransCanada's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransCanada's Management information circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransCanada.
3. Additional financial information is provided in TransCanada's audited consolidated financial statements and MD&A for its most recently completed financial year.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
km	Kilometre
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes rate base as well as assets under construction
LNG	Liquefied natural gas
NEB 2014 Decision	In response to the RH-01 2014 Decision on the Canadian Mainline's 2015-2030 Tolls Application
OM&A	Operating, maintenance and administration
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
rate base	Our annual average investment used
WCSB	Western Canada Sedimentary Basin

Accounting terms

DRP	Dividend reinvestment plan
GAAP	U.S. generally accepted accounting principles
ROE	Rate of return on common equity

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
DOS	Department of State (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations

Schedule A
Metric conversion table

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	Imperial	Factor
Kilometres (km)	Miles	0.62
Millimetres	Inches	0.04
Gigajoules	Million British thermal units	0.95
Cubic metres*	Cubic feet	35.3
Kilopascals	Pounds per square inch	0.15
Degrees Celsius	Degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees; to convert to Celsius subtract 32 degrees, then divide by 1.8

* The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15 degrees Celsius.

Schedule B
CHARTER OF THE AUDIT COMMITTEE

1. PURPOSE

The Audit Committee shall assist the Board of Directors (the Board) in overseeing and monitoring, among other things, the:

- Company's financial accounting and reporting process;
- integrity of the financial statements;
- Company's internal control over financial reporting;
- external financial audit process;
- compliance by the Company with legal and regulatory requirements; and
- independence and performance of the Company's internal and external auditors.

To fulfill its purpose, the Audit Committee has been delegated certain authorities by the Board that it may exercise on behalf of the Board.

2. ROLES AND RESPONSBILITIES

I. Appointment of the Company's External Auditor

Subject to confirmation by the external auditor of their compliance with Canadian and U.S. regulatory registration requirements, the Audit Committee shall recommend to the Board the appointment of the external auditor, such appointment to be confirmed by the Company's shareholders at each annual meeting. The Audit Committee shall also recommend to the Board the compensation to be paid to the external auditor for audit services. The Audit Committee shall also be directly responsible for the oversight of the work of the external auditor (including resolution of disagreements between management and the external auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The external auditor shall report directly to the Audit Committee.

The Audit Committee shall review and approve the audit plan of the external auditor. The Audit Committee shall also receive periodic reports from the external auditor regarding the auditor's independence, discuss such reports with the auditor, consider whether the provision of non-audit services is compatible with maintaining the auditor's independence and the Audit Committee shall take appropriate action to satisfy itself of the independence of the external auditor.

II. Oversight in Respect of Financial Disclosure

The Audit Committee, to the extent it deems it necessary or appropriate, shall:

a) review, discuss with management and the external auditor and recommend to the Board for approval, the Company's audited annual consolidated financial statements, annual information form, management's discussion and analysis, all financial information in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including, without limitation, the annual management information circular, but excluding any pricing or prospectus supplement relating to the issuance of debt securities of the Company;

b) review, discuss with management and the external auditor and recommend to the Board for approval, the release to the public of the Company's interim reports, including the consolidated financial statements, management's discussion and analysis and press releases on quarterly financial results;

c) review and discuss with management and the external auditor the use of non-GAAP information and the applicable reconciliation;

d) review and discuss with management any financial outlook or future-oriented financial information disclosure in advance of its public release; provided, however, that such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Audit Committee need not discuss in advance each instance in which the Company may provide financial projections or presentations to credit rating agencies;

e) review with management and the external auditor major issues regarding accounting and auditing policies and practices, including any significant changes in the Company's selection or application of accounting policies, as well as major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies that could significantly affect the Company's financial statements;

f) review and discuss quarterly findings reports from the external auditor on:

(i) all critical accounting policies and practices to be used;

(ii) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor;

(iii) other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences;

g) review with management and the external auditor the effect of regulatory and accounting developments as well as any off-balance sheet structures on the Company's financial statements;

h) review with management, the external auditor and, if necessary, legal counsel, any litigation, claim or contingency, including arbitration and tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;

i) review disclosures made to the Audit Committee by the Company's CEO and CFO during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls;

j) discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies;

III. Oversight in Respect of Legal and Regulatory Matters

(a) review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's compliance policies and any material reports or inquiries received from regulators or governmental agencies;

IV. Oversight in Respect of Internal Audit

(a) review and approve the audit plans of the internal auditor of the Company including the degree of coordination between such plans and that of the external auditor and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;

(b) review the significant findings prepared by the internal audit department and recommendations issued by it or by any external party relating to internal audit issues, together with management's response thereto;

(c) review compliance with the Company's policies and avoidance of conflicts of interest;

(d) review the report prepared by the internal auditor on officers' expenses and aircraft usuage;

(e) review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with subsidiaries and affiliates;

(f) ensure the internal auditor has access to the Chair of the Audit Committee, the Board and the Chief Executive Officer and meet separately with the internal auditor to review with him or her any problems or difficulties he or she may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;

(ii) any changes required in the planned scope of the internal audit;

(iii) the internal audit department responsibilities, budget and staffing; and to report to the Board on such meetings;

V. Insight in Respect of the External Auditor

(a) review any letter, report or other communication from the external auditor in respect of any identified weakness or unadjusted difference and management's response and follow-up, inquire regularly of management and the external auditor of any significant issues between them and how they have been resolved, and intervene in the resolution if required;

(b) receive and review annually the external auditor's formal written statement of independence delineating all relationships between itself and the Company;

(c) meet separately with the external auditor to review any problems or difficulties the external auditor may have encountered and specifically:

  (i) any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management;

  (ii) any changes required in the planned scope of the audit; and to report to the Board on such meetings;

(d) meet with the external auditor prior to the audit to review the planning and staffing of the audit;

(e) receive and review annually the external auditor's written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;

(f) review and evaluate the external auditor, including the lead partner of the external auditor team;

(g) ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years;

VI. Oversight in Respect of Audit and Non-Audit Services

(a) pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:

  (i) the aggregate amount of all such non-audit services provided to the Company that were not pre-approved constitutes not more than 5 per cent of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;

  (ii) such services were not recognized by the Company at the time of the engagement to be non-audit services;

  (iii) such services are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee;

(b) approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;

(c) the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval;

(d) if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection;

VII. Oversight in Respect of Certain Policies

(a) review and recommend to the Board for approval the implementation of, and significant amendments to, policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's code of business ethics (COBE) risk management and financial reporting policies;

(b) obtain reports from management, the Company's senior internal auditing executive and the external auditors and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's codes of business conduct and COBE;

(c) establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;

(d) annually review and assess the adequacy of the Company's public disclosure policy;

(e) review and approve the Company's hiring policies for partners, employees and former partners and employees of the present and former external auditor (recognizing the *Sarbanes-Oxley Act of 2002* does not permit the CEO, controller, CFO or chief accounting officer to have participated in the Company's audit as an employee of the external auditor during the preceding one-year period) and monitor the Company's adherence to the policy;

VIII. *Oversight in Respect of Financial Aspects of the Company's Canadian Pension Plans (the Company's pension plans), specifically:*

(a) review and approve annually the Statement of Investment Beliefs for the Company's pension plans;

(b) delegate the ongoing administration and management of the financial aspects of the Canadian pension plans to the Pension Committee comprised of members of the Company's management team appointed by the Human Resources Committee, in accordance with the Pension Committee Charter, which terms shall be approved by both the Audit Committee and the Human Resources Committee, and the terms of the Statement of Investment Beliefs;

(c) monitor the financial management activities of the Pension Committee and receive updates at least annually from the Pension Committee on the investment of the Plan assets to ensure compliance with the Statement of Investment Beliefs;

(d) provide advice to the Human Resources Committee on any proposed changes in the Company's pension plans in respect of any significant effect such changes may have on pension financial matters;

(e) review and consider financial and investment reports and the funded status relating to the Company's pension plans and recommend to the Board on pension contributions;

(f) receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;

(g) approve the initial selection or change of actuary for the Company's pension plans;

(h) approve the appointment or termination of auditor;

IX. U.S. Stock Plans

(a) review and approve the engagement and related fees of the auditor for any plan of a U.S. subsidiary that offers Company stock to employees as an investment option under the plan;

X. Oversight in Respect of Internal Administration

(a) review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates;

(b) oversee succession planning for the senior management in finance, treasury, tax, risk, internal audit and the controllers' group; and

XI. Information Security

(a) review, at least quarterly, the report of the Chief Information Officer (or such other appropriate Company representative) on information security controls, education and awareness.

XII. Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external auditor. The Audit Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Audit Committee to provide broad oversight of the financial disclosure, financial risk and control related activities of the Company, and are specifically not accountable nor responsible for the day to day operation of such activities. Although designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Audit Committee, designation as an "audit committee financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board in the absence of such designation. Rather, the role of any audit committee financial expert, like the role of all

Audit Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Company's financial information or public disclosure.

3. COMPOSITION OF AUDIT COMMITTEE

The Audit Committee shall consist of three or more Directors, a majority of whom are resident Canadians (as defined in the *Canada Business Corporations Act*), and all of whom are unrelated and/or independent for the purposes of applicable Canadian and United States securities law and applicable rules of any stock exchange on which the Company's securities are listed. Each member of the Audit Committee shall be financially literate and at least one member shall have accounting or related financial management expertise (as those terms are defined from time to time under the requirements or guidelines for audit committee service under securities laws and the applicable rules of any stock exchange on which the Company's securities are listed for trading or, if it is not so defined, as that term is interpreted by the Board in its business judgment).

4. APPOINTMENT OF AUDIT COMMITTEE MEMBERS

The members of the Audit Committee shall be appointed by the Board from time to time, on the recommendation of the Governance Committee and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be Directors of the Company.

5. VACANCIES

Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. AUDIT COMMITTEE CHAIR

The Board shall appoint a Chair of the Audit Committee who shall:

(a) review and approve the agenda for each meeting of the Audit Committee and, as appropriate, consult with members of management;

(b) preside over meetings of the Audit Committee;

(c) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;

(d) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and

(e) meet as necessary with the internal and external auditor.

7. ABSENCE OF AUDIT COMMITTEE CHAIR

If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. SECRETARY OF AUDIT COMMITTEE

The Corporate Secretary shall act as Secretary to the Audit Committee.

9. MEETINGS

The Chair, or any two members of the Audit Committee, or the internal auditor, or the external auditor, may call a meeting of the Audit Committee. The Audit Committee shall meet at least quarterly. The Audit Committee shall meet periodically with management, the internal auditor and the external auditor in separate executive sessions.

10. QUORUM

A majority of the members of the Audit Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. NOTICE OF MEETINGS

Notice of the time and place of every meeting shall be given in writing, facsimile communication or by other electronic means to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. ATTENDANCE OF COMPANY OFFICERS AND EMPLOYEES AT MEETING

At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. PROCEDURE, RECORDS AND REPORTING

The Audit Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Audit Committee may deem appropriate but not later than the next meeting of the Board.

14. REVIEW OF CHARTER AND EVALUATION OF AUDIT COMMITTEE

The Audit Committee shall review its Charter annually or otherwise, as it deems appropriate and, if necessary, propose changes to the Governance Committee and the Board. The Audit Committee shall annually review the Audit Committee's own performance.

15. OUTSIDE EXPERTS AND ADVISORS

The Audit Committee is authorized, when deemed necessary or desirable, to retain and set and pay the compensation for independent counsel, outside experts and other advisors, at the Company's expense, to advise the Audit Committee or its members independently on any matter.

16. RELIANCE

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Audit Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Company from which it receives information, (ii) the accuracy of the financial and other information provided to the Audit Committee by such persons or organizations and (iii) representations made by management and the external auditor, as to any information technology, internal audit and other non-audit services provided by the external auditor to the Company and its subsidiaries.

Management's discussion and analysis

February 10, 2016

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 year ended December 31, 2015.

This MD&A should be read with our accompanyingDecember 31, 2015 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

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GLOSSARY **118**

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 the document are defined in the glossary on page 118. All information is as of February 10, 2016 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 common share purchases under our normal course issuer bid
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this 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 and credit risk of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest, tax and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (SEC).

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

FOR MORE INFORMATION

See Supplementary information beginning on page 184 for other consolidated financial information on TransCanada for the last five years.

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

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- distributable cash flow
- distributable cash flow per common share
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable distributable cash flow
- comparable distributable cash flow per common share
- comparable income from equity investments
- comparable depreciation and amortization
- comparable interest expense
- comparable interest income and other
- comparable income tax expense
- comparable income attributable to non-controlling interests.

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

Funds generated from operations

Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating performance of our assets. See the Financial condition section for a reconciliation to net cash provided by operations.

Distributable cash flow

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

Our decision not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of assets and investments.

In calculating comparable earnings and other comparable measures we exclude the unrealized gains and losses from changes in the fair value of 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 unrealized changes in fair value do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

About our business

With over 65 years of experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and natural gas storage facilities.

THREE CORE BUSINESSES

We operate our business in three segments – Natural Gas Pipelines, Liquids Pipelines and Energy. We also have a non-operational Corporate segment consisting of corporate and administrative functions that provide support and governance to our operational business segments.

Our $64 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 36 U.S. states and Mexico.

Natural Gas Pipelines

Canadian Pipelines

1 NGTL System
2 Canadian Mainline
3 Foothills
4 Trans Québec & Maritimes (TQM)

U.S. Pipelines

5 ANR Pipeline
5a ANR Regulated Natural Gas Storage
6 Bison
7 Gas Transmission Northwest (GTN)
8 Great Lakes
9 Iroquois
10 North Baja
11 Northern Border
12 Portland
13 Tuscarora
14 TC Offshore[1]

Mexican Pipelines

15 Guadalajara
16 Tamazunchale

Under Construction

17 Mazatlan Pipeline
18 Topolobampo Pipeline
19 Tuxpan-Tula Pipeline

In Development

20 Coastal GasLink
21 Prince Rupert Gas Transmission
22 North Montney Mainline
23 Merrick Mainline
24 Eastern Mainline

Liquids Pipelines

Canadian / U.S. Pipelines

25 Keystone Pipeline System
26 Cushing Marketlink and Terminal

Under Construction

27 Houston Lateral
28 Houston Terminal
29 Grand Rapids Pipeline
30 Northern Courier Pipeline

In Development

31 Bakken Marketlink
32 Keystone Hardisty Terminal
33 Keystone XL
34 Heartland Pipeline
35 TC Terminals
36 Energy East Pipeline
37 Upland Pipeline

[1] *As at December 31, 2015, TC Offshore was classified as Assets held for sale*

[2] *Located in Arizona, results reported in Canadian – Western Power*

[3] *Acquired February 1, 2016*

Energy

Canadian - Western Power

38 Bear Creek
39 Carseland
40 Coolidge[2]
41 Mackay River
42 Redwater
43 Sheerness PPA
44 Sundance A PPA
44 Sundance B PPA

Canadian - Eastern Power

45 Bécancour
46 Cartier Wind
47 Grandview
48 Halton Hills
49 Portlands Energy
50 Ontario Solar (8 Facilities)

Bruce Power

51 Bruce

U.S. Power

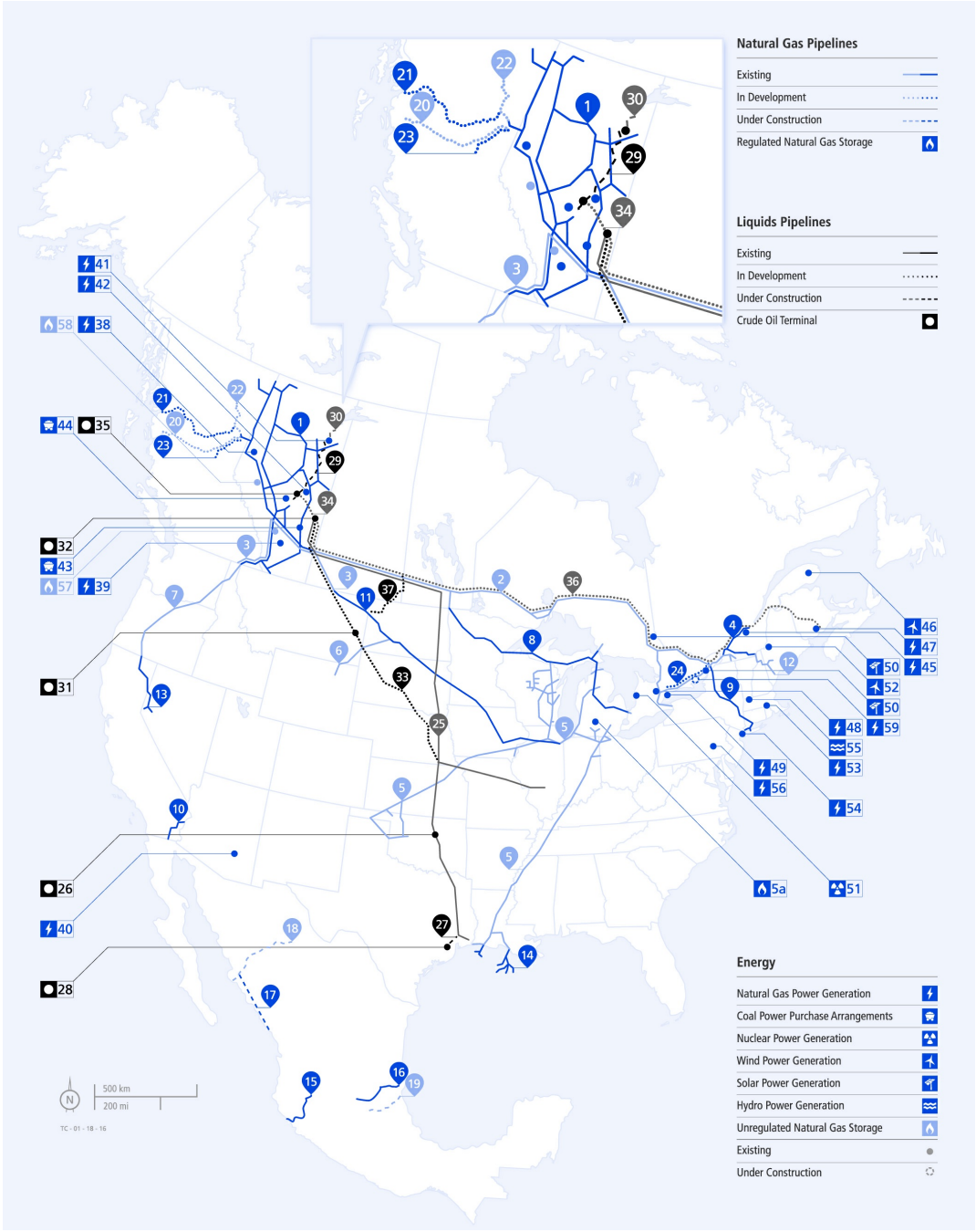
52 Kibby Wind
53 Ocean State Power
54 Ravenswood
55 TC Hydro
56 Ironwood[3]

Unregulated Natural Gas Storage

57 CrossAlta
58 Edson

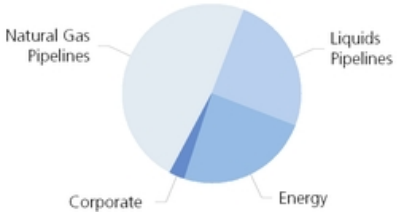
Under Construction

59 Napanee

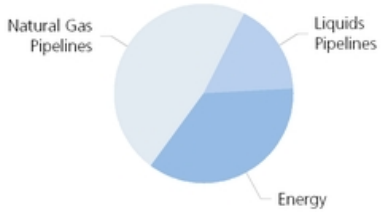

Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
Liquids Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
Existing
Under Construction
500 km
200 mi

Year at a glance

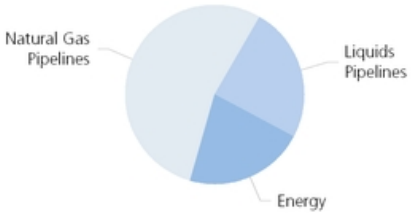
at December 31 (millions of $)	2015	2014
Total assets		
Natural Gas Pipelines	**31,072**	27,103
Liquids Pipelines	**16,046**	16,116
Energy	**15,558**	14,197
Corporate	**1,807**	1,109
	64,483	58,525



year ended December 31 (millions of $)	2015	2014
Total revenues		
Natural Gas Pipelines	**5,383**	4,913
Liquids Pipelines	**1,879**	1,547
Energy	**4,038**	3,725
	11,300	10,185



year ended December 31 (millions of $)	2015	2014
Comparable EBIT		
Natural Gas Pipelines	**2,345**	2,178
Liquids Pipelines	**1,056**	843
Energy	**944**	1,039
Corporate	**(202)**	(150)
	4,143	3,910

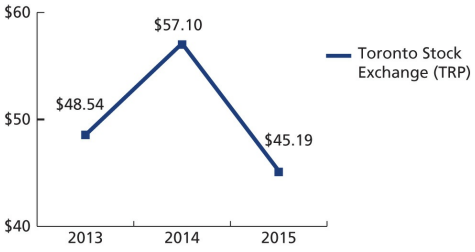


Common share price

at December 31

Common shares outstanding – average

(millions)	
2015	709



2014	708
2013	707

as at February 5, 2016 Common shares	issued and outstanding
	702 million

Preferred shares	issued and outstanding	convertible to
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares

options to buy common shares	outstanding	exercisable
	10 million	6 million

OUR STRATEGY

Our energy infrastructure business is made up of pipeline and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

Our vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy at a glance

1 Maximize the full-life value of our infrastructure assets and commercial positions

- Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low-risk business model.
- Our pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flow and earnings.
- In Energy, long-term power sale agreements and shorter-term power sales to wholesale and load customers are used to manage and optimize our portfolio and to manage price volatility.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current $58 billion capital program, comprised of $13 billion in near-term projects and $45 billion in medium to long-term projects. These will contribute incremental earnings over the near, medium and long terms as our investments are placed in service.
- Our expertise in managing construction risks and maximizing capital productivity ensures a disciplined approach to reliability, cost and schedule, resulting in superior service for our customers and returns to shareholders.
- As part of our growth strategy, we rely on this experience and our regulatory, commercial, financial, legal and operational expertise to successfully build and integrate new energy and pipeline facilities.
- Our growing investment in natural gas, nuclear, wind, hydro and solar generating facilities demonstrates our commitment to clean, sustainable energy.

3 Cultivate a focused portfolio of high quality development and investment options

- We assess opportunities to acquire and develop energy infrastructure that complements our existing portfolio and diversifies access to attractive supply and market regions.
- We focus on pipelines and energy growth initiatives in core regions of North America and prudently manage development costs, minimizing capital-at-risk in early stages of projects.
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns are acceptable.

4 Maximize our competitive strengths

- We are continually developing core competencies in areas such as operational excellence, supply chain management, project execution and stakeholder management to ensure we provide maximum shareholder value over the short, medium and long terms.

A competitive advantage

Years of experience in the energy infrastructure business and a disciplined approach to project and operational management and capital investment give us our competitive edge.

- Strong leadership: scale, presence, operating capabilities and strategy development; expertise in regulatory, legal, commercial and financing support.
- High quality portfolio: a low-risk and enduring business model that maximizes the full-life value of our long-life assets and commercial positions throughout all business cycles.
- Disciplined operations: highly skilled in designing, building and operating energy infrastructure; focus on operational excellence; and a commitment to health, safety and the environment are paramount parts of our core values.
- Financial positioning: excellent reputation for consistent financial performance and long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth; ability to balance an increasing dividend on our common shares while preserving financial flexibility to fund our industry-leading capital program in all market conditions.
- Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our value to equity and debt investors – both the upside and the risks – to build trust and support.

CAPITAL PROGRAM

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

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

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

at December 31, 2015 (billions of $)	**Estimated project cost**	**Carrying value**
Summary		
Near-term	13.4	3.9
Medium to longer-term	45.2	2.1
Total capital program	**58.6**	**6.0**
Foreign exchange impact on Capital Program[1]	4.5	0.8

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

Near-term projects

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

1 Our proportionate share.

Medium to longer-term projects

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

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

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

2015 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be similar to measures provided by other companies.

Comparable EBITDA (comparable earnings before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share, funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. See page 10 for more information about the non-GAAP measures we use and pages 84 and 108 for a reconciliation to their GAAP equivalents.

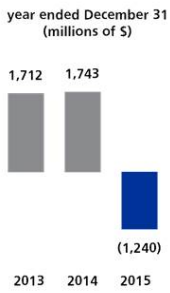
year ended December 31 (millions of $, except per share amounts)	2015	2014	2013
Income			
Revenues	**11,300**	10,185	8,797
Net (loss)/income attributable to common shares	**(1,240)**	1,743	1,712
per common share – basic & diluted	**($1.75)**	$2.46	$2.42
Comparable EBITDA	**5,908**	5,521	4,859
Comparable earnings	**1,755**	1,715	1,584
per common share	**$2.48**	$2.42	$2.24
Cash flows			
Funds generated from operations	**4,513**	4,268	4,000
Increase in working capital	**(398)**	(189)	(326)
Net cash provided by operations	**4,115**	4,079	3,674
Comparable distributable cash flow	**3,546**	3,406	3,234
per common share	**$5.00**	$4.81	$4.57
Capital spending – capital expenditures	**3,918**	3,489	4,264
Capital spending – projects in development	**511**	848	488
Contributions to equity investments	**493**	256	163
Acquisitions, net of cash acquired	**236**	241	216
Proceeds from sale of assets, net of transaction costs	**—**	196	—
Balance sheet			
Total assets	**64,483**	58,525	53,898
Long-term debt	**31,584**	24,757	22,865
Junior subordinated notes	**2,422**	1,160	1,063
Preferred shares	**2,499**	2,255	1,813
Non-controlling interests	**1,717**	1,583	1,611
Common shareholders' equity	**13,939**	16,815	16,712
Dividends declared			
per common share	**$2.08**	$1.92	$1.84
per Series 1 preferred share	**$0.8165**	$1.15	$1.15
per Series 2 preferred share[1]	**$0.6299**	—	—
per Series 3 preferred share	**$0.769**	$1.00	$1.00
per Series 4 preferred share[2]	**$0.2269**	—	—
per Series 5 preferred share	**$1.10**	$1.10	$1.10
per Series 7 preferred share	**$1.00**	$1.00	$0.91
per Series 9 preferred share[3]	**$1.0625**	$1.09	—
per Series 11 preferred share[4]	**$0.704**	—	—

1 Issued December 2014 upon conversion of Series 1 preferred shares.
2 Issued June 2015 upon conversion of Series 3 preferred shares.
3 Issued January 2014.
4 Issued March 2015.

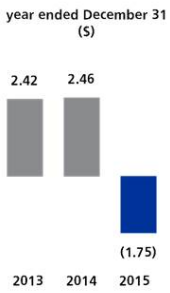
Consolidated results

year ended December 31 (millions of $, except per share amounts)	2015	2014	2013
Segmented earnings/(losses)			
Natural Gas Pipelines	**2,220**	2,187	1,881
Liquids Pipelines	**(2,630)**	843	603
Energy	**812**	1,051	1,113
Corporate	**(301)**	(150)	(124)
Total segmented earnings	**101**	3,931	3,473
Interest expense	**(1,370)**	(1,198)	(985)
Interest income and other	**163**	91	34
(Loss)/income before income taxes	**(1,106)**	2,824	2,522
Income tax expense	**(34)**	(831)	(611)
Net (loss)/income	**(1,140)**	1,993	1,911
Net income attributable to non-controlling interests	**(6)**	(153)	(125)
Net (loss)/income attributable to controlling interests	**(1,146)**	1,840	1,786
Preferred share dividends	**(94)**	(97)	(74)
Net (loss)/income attributable to common shares	**(1,240)**	1,743	1,712
Net (loss)/income per common share - basic and diluted	**($1.75)**	$2.46	$2.42

Net (loss)/income attributable to common shares



Net (loss)/income per share



Net (loss)/income attributable to common shares in2015 was a loss of$1,240 million (2014 – income of $1,743 million; 2013 –income of $1,712 million). The following specific items were recognized in net (loss)/income attributable to common shares in 2013 to 2015 and were excluded from comparable earnings for the relevant periods:

2015

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore expected to close in early 2016
- a net charge of $74 million after tax for restructuring charges comprised of $42 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value on turbine equipment held for future use in our Energy business

- a $34 million adjustment to income tax expense due to the enactment of a two per cent increase in the Alberta corporate income tax rate in June 2015
- a charge of $27 million after tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

2014

- a gain of $99 million after tax on the sale of Cancarb Limited and its related power generation business
- a net loss of $32 million after tax resulting from a termination payment to Niska Gas Storage for contract restructuring
- a gain of $8 million after tax on the sale of our 30 per cent interest in Gas Pacifico/INNERGY.

2013

- net income of $84 million recorded in 2013 related to 2012 from the NEB 2013 decision on the Canadian Restructuring Proposal (NEB 2013 Decision)
- a favourable tax adjustment of $25 million due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax.

Certain unrealized fair value adjustments relating to risk management activities are also excluded from comparable earnings. The remainder of net (loss)/income is equivalent to comparable earnings. A reconciliation of net (loss)/income attributable to common shares to comparable earnings is shown in the following table.

Refer to the Results section in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

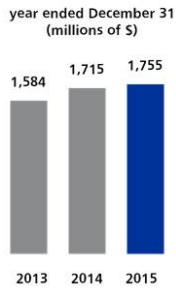
Reconciliation of net (loss)/income to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2015	2014	2013
Net (loss)/income attributable to common shares	**(1,240)**	1,743	1,712
Specific items (net of tax):			
Keystone XL impairment charge	**2,891**	—	—
TC Offshore loss on sale	**86**	—	—
Restructuring costs	**74**	—	—
Turbine equipment impairment charge	**43**	—	—
Alberta corporate income tax rate increase	**34**	—	—
Bruce Power merger – debt retirement charge	**27**	—	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**(199)**	—	—
Cancarb gain on sale	**—**	(99)	—
Niska contract termination	**—**	32	—
Gas Pacifico/ INNERGY gain on sale	**—**	(8)	—
NEB 2013 Decision – 2012	**—**	—	(84)
Part VI.I income tax adjustment	**—**	—	(25)
Risk management activities[1]	**39**	47	(19)
Comparable earnings	**1,755**	1,715	1,584
Net (loss)/income per common share	**($1.75)**	$2.46	$2.42
Specific items (net of tax):			
Keystone XL impairment charge	**4.08**	—	—
TC Offshore loss on sale	**0.12**	—	—
Restructuring costs	**0.10**	—	—
Turbine equipment impairment charge	**0.06**	—	—
Alberta corporate income tax rate increase	**0.05**	—	—
Bruce Power merger – debt retirement charge	**0.04**	—	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**(0.28)**	—	—
Cancarb gain on sale	**—**	(0.14)	—
Niska contract termination	**—**	0.04	—
Gas Pacifico/ INNERGY gain on sale	**—**	(0.01)	—
NEB 2013 Decision – 2012	**—**	—	(0.12)
Part VI.I income tax adjustment	**—**	—	(0.04)
Risk management activities	**0.06**	0.07	(0.02)
Comparable earnings per common share	**$2.48**	$2.42	$2.24

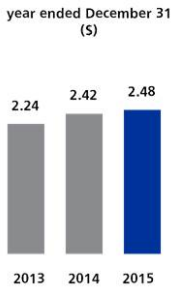
1

year ended December 31 (millions of $)	2015	2014	2013
Canadian Power	**(8)**	(11)	(4)
U.S. Power	**(30)**	(55)	50
Natural Gas Storage	**1**	13	(2)
Foreign exchange	**(21)**	(21)	(9)
Income tax attributable to risk management activities	**19**	27	(16)
Total (losses)/gains from risk management activities	**(39)**	(47)	19

Comparable earnings



Comparable earnings per share



Comparable earnings in 2015 were $40 million higher than in 2014, an increase of $0.06 per common share.

The increase in comparable earnings was primarily the net result of:

- higher earnings from Liquids Pipelines due to higher volumes on the Keystone Pipeline System
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes
- higher interest expense as a result of long term debt issuances net of maturities
- higher interest income and other as a result of increased AFUDC related to our rate-regulated pipeline projects including Energy East Pipeline and our Mexico pipelines
- higher earnings from U.S. Power due to increased margins and sales volumes to wholesale, commercial and industrial customers, partially offset by lower capacity revenue in New York and lower realized prices at our northeastern U.S. Power facilities
- higher earnings from U.S. Natural Gas Pipelines due to higher ANR, Great Lakes and GTN transportation revenues
- higher earnings from Eastern Power primarily due to four solar facilities acquired in 2014
- higher earnings from the Tamazunchale Extension which was placed in service in 2014.

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

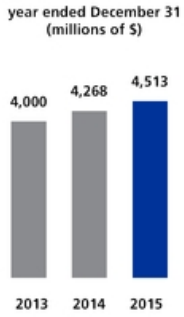
Comparable earnings in 2014 were $131 million higher than 2013, an increase of $0.18 per common share.

The increase in comparable earnings was primarily the net result of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System which was placed in service in January 2014
- higher interest expense from debt issuances and lower capitalized interest due to projects placed in service
- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher earnings from U.S. Natural Gas Pipelines due to higher transportation revenues at Great Lakes reflecting colder winter weather and increased demand, partially offset by lower contributions from GTN and Bison following the reductions in our effective ownership in July 2013 (GTN and Bison) and October 2014 (Bison)
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices at our New York and New England facilities
- higher earnings from the Canadian Mainline due to higher incentive earnings
- incremental earnings from Eastern Power primarily due to solar facilities acquired in 2013 and 2014.

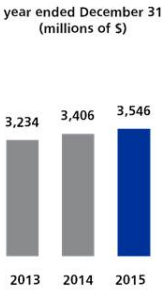
Cash flows

Funds generated from operations

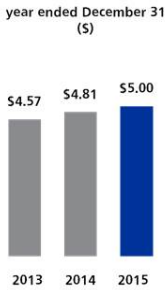


Funds generated from operations were six per cent higher in 2015 compared to 2014 primarily due to higher comparable earnings, as described above.

Comparable distributable cash flow



Comparable distributable cash flow per share



Comparable distributable cash flow and comparable distributable cash flow per common share increased in 2015 compared to 2014 primarily due to higher comparable earnings, as described above. See the Financial condition section for more information on the calculation of comparable distributable cash flow.

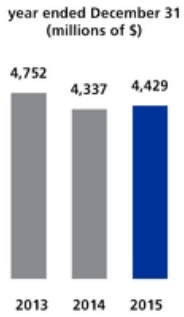
Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2015	2014	2013
Natural Gas Pipelines	**2,699**	2,136	2,021
Liquids Pipelines	**1,290**	1,949	2,529
Energy	**376**	206	152
Corporate	**64**	46	50
	4,429	4,337	4,752

[1] Capital spending includes capital expenditures, maintenance capital expenditures and capital projects in development.

Capital spending



We invested $4.4 billion in capital projects in 2015 as part of our ongoing growth program which is a key part of our strategy to optimize the value of our existing assets and develop new, complementary assets in high demand areas that are expected to generate stable, predictable earnings and cash flow and to maximize returns to shareholders for years to come.

Contributions to equity investments and acquisitions

In 2015, we made contributions of $493 million to our equity investments primarily related to the construction of Grand Rapids and we spent $236 million to increase our ownership in Bruce Power.

Balance sheet

We continue to maintain a solid balance sheet while growing our total assets by $10.6 billion since 2013. At December 31, 2015, common equity represented 30 per cent (38 per cent in 2014) of our capital structure, after giving effect to the various 2015 specific items outlined on pages 20 and 21. See page 83 for more information about our capital structure.

Common shares repurchased

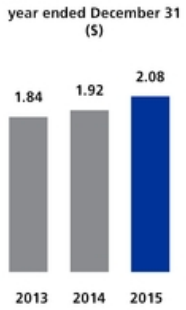
On November 19, 2015, we announced that the Toronto Stock Exchange (TSX) approved our normal course issuer bid (NCIB), which allows for the repurchase and cancellation of up to 21.3 million of our common shares, representing three per cent of our issued and outstanding common shares, between November 23, 2015 and November 22, 2016, at prevailing market prices plus brokerage fees, or such other prices as may be permitted by the TSX.

As of February 10, 2016, we repurchased 7.1 million common shares at an weighted-average price per common share of $43.36 for a total cost of $307 million.

Dividends

We increased the quarterly dividend on our outstanding common shares by nine per cent to $0.565 per common share for the quarter ending March 31, 2016 which equates to an annual dividend of $2.26 per common share and reflects our commitment to grow our common share dividend at an average annual rate of eight to ten per cent through 2020. This is the 16th consecutive year we have increased the dividend on our common shares.

Dividends declared per common share



Dividend reinvestment plan

Under our dividend reinvestment plan (DRP), eligible holders of TransCanada common or preferred shares can reinvest their dividends and make optional cash payments to buy additional TransCanada common shares on the open market.

Quarterly dividend on our common shares

$0.565 per common share (for the quarter ending March 31, 2016)

Annual dividends on our preferred shares [1]

Series 1 $0.8165[2]

Series 2 $0.6045[3]

Series 3 $0.538[4]

Series 4 $0.4445[3]

Series 5 $0.56575[5]

Series 6 $0.50925[6]

Series 7 $1.00

Series 9 $1.0625

Series 11 $0.95

1 Annual dividend based on applicable annual or quarterly floating rate as of February 10, 2016.
2 Dividend rate changed in December 2014.
3 Floating quarterly dividend rate resets each quarter. See the Financial condition section for more information.
4 Series 3 preferred shares dividend rate changed in June 2015.
5 Series 5 preferred shares dividend rate changed in February 2016.
6 Series 6 preferred shares were issued February 1, 2016.

Cash dividends

year ended December 31 (millions of $)	2015	2014	2013
Common shares	**1,446**	1,345	1,285
Preferred shares	**92**	94	71

OUTLOOK

Earnings

We anticipate our 2016 earnings, after excluding specific items, to be higher than 2015 mainly due to the following:

- Expected earnings from Topolobampo and Mazatlan Pipeline projects coming into service
- Positive impact of a stronger U.S. dollar on U.S. denominated earnings
- Increase in the average investment base for the NGTL System
- Higher earnings associated with incremental contracts from ANR
- Cost savings achieved as a result of corporate restructuring
- Consistent earnings in Energy with higher earnings in U.S. Power, relatively consistent earnings in Western Power and Bruce Power and slightly lower earnings in Eastern Power.

Partially offset by:

- Reduced capitalized interest due to the Keystone XL Pipeline project Presidential permit denial
- Lower anticipated earnings from the Keystone Pipeline System based on expiring short-term contracts for Cushing Marketlink.

Natural Gas Pipelines

Earnings from the Natural Gas Pipelines segment are affected by regulatory decisions and the timing of these decisions. Earnings are also impacted by market conditions, which drive the level of demand and the rates we secure for our services.

Canadian Mainline earnings are anticipated to be lower in 2016 due to a declining investment base. These lower earnings are expected to be largely offset by growth in the NGTL System investment base as we continue to invest in connecting new natural gas supply and respond to growing demand in the northeastern B.C. and Alberta markets.

U.S. and International Gas Pipelines earnings in 2016 are expected to be higher than 2015 as we pursue opportunities for continued growth in end use markets for natural gas and evaluate our commercial and operational positions in ANR and Great Lakes in response to positive developments in supply fundamentals in those market areas. On January 29th, 2016, ANR filed a Section 4 Rate Case with the FERC to increase its base rates. We anticipate that the proposed rates, which are subject to customer refund and pending final FERC approval, will take effect in third quarter 2016.

Mexico Pipeline earnings are expected to be higher in 2016 as the Topolobampo and Mazatlan Pipeline projects come into service in late 2016.

Liquids Pipelines

With the exception of the Keystone XL impairment impact, our 2016 earnings are expected to be slightly lower than our 2015 earnings due to short term contract expiration and market conditions related to the lower crude oil price environment.

Energy

Earnings in the Energy segment are generally maximized by maintaining and optimizing the operations of our power plants and through various marketing activities. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term arrangements or at spot prices will continue to be affected by fluctuations in commodity prices. Overall we expect Energy earnings in 2016 to be consistent with 2015.

Western Power earnings in 2016 are anticipated to be consistent with 2015 as a result of a well-supplied Alberta power market, slower demand growth and lower natural gas prices. Negative pressure on earnings in 2016 is expected due to the increase in the government imposed emissions reductions targets and higher per tonne GHG emissions costs.

Eastern Power earnings in 2016 are expected to be slightly lower as a result of the lower contractual earnings at Bécancour and reduced earnings from the sale of unused natural gas transportation.

Bruce Power equity income in 2016 is expected to be consistent with 2015 results. The net impact of the additional ownership interest obtained in Bruce Power in 2015 is anticipated to be largely offset by the increased planned maintenance activity in 2016.

U.S. Power results in 2016 are expected to be higher than 2015 due to the net impact of the additional earnings from the acquisition of the Ironwood natural gas fired, combined cycle power plant and lower marketing margins reflecting the return to normalized levels of costs and decreased volatility of forward natural gas and power prices in the New England market.

Natural Gas Storage earnings are expected to be higher as a modest recovery of seasonal spreads is expected to occur in 2016.

Consolidated capital spending, equity investments and acquisition

We expect to spend approximately $6 billion in 2016 on new and existing capital projects. Capital spending includes capital expenditures on growth projects, maintenance capital expenditures and contributions to equity investments. The 2016 capital spending relates to Natural Gas Pipelines projects including NGTL System expansion, the Canadian Mainline, Tuxpan-Tula and Topolobampo; Liquids Pipelines projects including Grand Rapids, Northern Courier and Energy East; and Energy projects including Bruce Power and Napanee. Additionally, on February 1, 2016 we acquired Ironwood Power Plant for approximately US$657 million before post closing adjustments.

Natural Gas Pipelines

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. We serve more than 80 per cent of the Canadian demand and approximately 15 per cent of the U.S. demand on a daily basis by connecting major natural gas supply basins and markets through:

- wholly-owned natural gas pipelines – 56,600 km (35,200 miles)
- partially-owned natural gas pipelines – 10,700 km (6,700 miles).

We also have regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf, making us one of the largest providers of natural gas storage and related services in North America.

Strategy at a glance

Optimizing the value of our existing natural gas pipelines systems, while responding to the changing flow patterns of natural gas in North America, is a top priority.

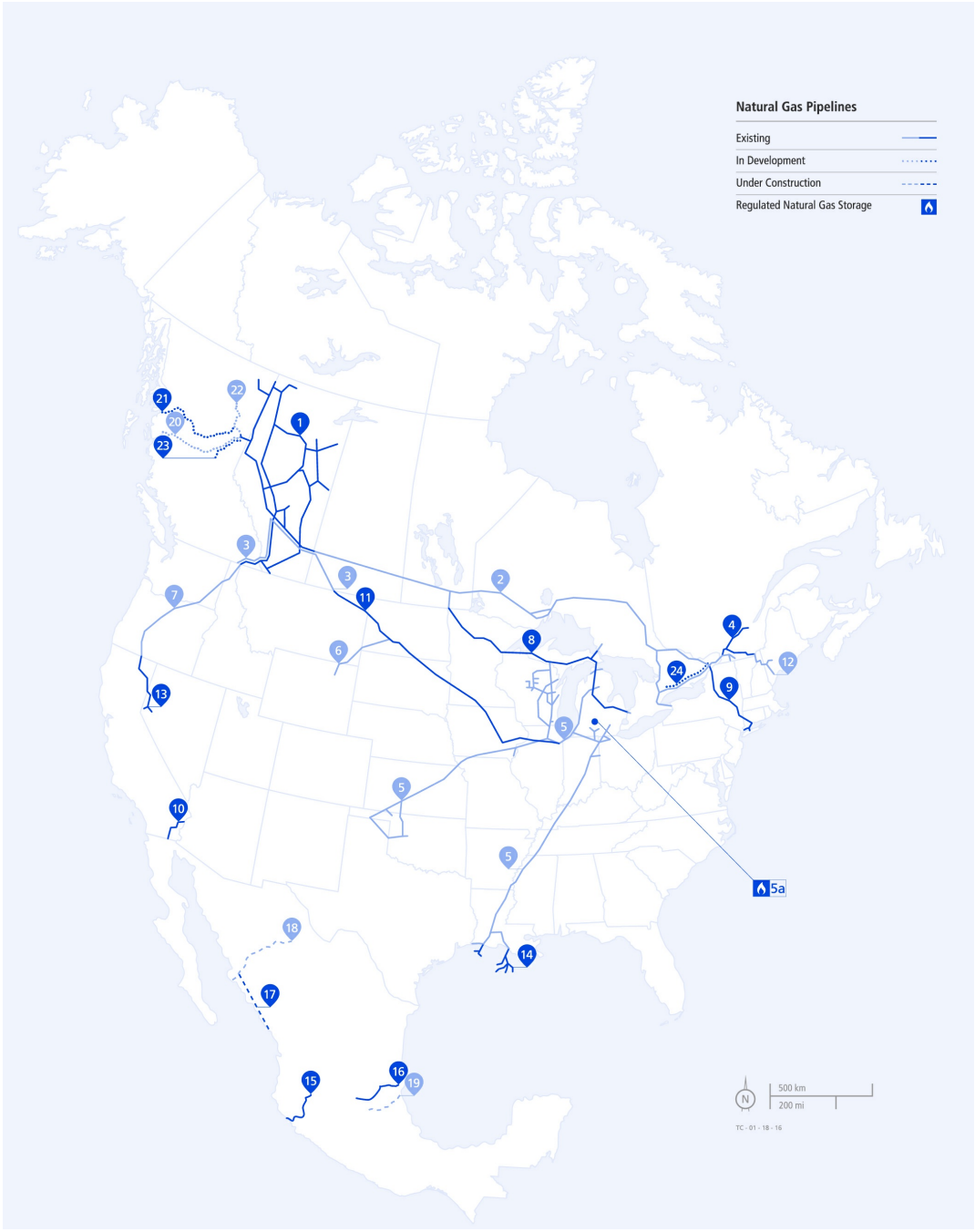
We are also pursuing new pipeline opportunities to add incremental value to our business. Our key areas of focus include:

- greenfield development projects, such as infrastructure for liquefied natural gas (LNG) exports from the west coast of Canada and the Gulf of Mexico
- additional new pipeline developments within Mexico
- connections to emerging Canadian and U.S. shale gas and other supplies
- connections to new and growing markets

all of which play a critical role in meeting the transportation requirements for supply and demand for natural gas in North America.

Highlights from 2015

- We were awarded the contract to build, own and operate the 36-inch diameter Tuxpan-Tula pipeline in Mexico which is approximately 250 km (155 miles) long and has a contracted capacity of 866 MMcf/d. The pipeline is expected to begin construction in 2016 and be in-service in fourth quarter 2017.
- The NEB approved the NGTL System's $1.7 billion North Montney Mainline Project on June 11, 2015. Construction remains subject to a positive FID on the proposed Pacific Northwest LNG Project.
- The NEB approved the Canadian Mainline's compliance filing on the NEB 2014 Decision as applied for. The approval was the last step in getting the NEB 2014 Decision implemented and allowing the Canadian Mainline to recognize incentive earnings.
- The NEB approved the Kings North Connection project on the Canadian Mainline which will increase gas transmission capacity into the greater Toronto area and provide shippers with the flexibility to source growing supplies of Marcellus gas from the U.S. Northeast.
- An agreement was reached with eastern LDCs that resolves their issues with Energy East and the Eastern Mainline Project. The agreement honours our previously stated commitment to ensure that Energy East and the Canadian Mainline's Eastern Mainline Project will provide gas consumers in Eastern Canada with sufficient natural gas transmission capacity and reduced natural gas transmission costs.
- We continued the drop down of U.S. natural gas pipeline assets into TC PipeLines, LP, with the sale of the remaining 30% of GTN in April 2015 and 49.9% of PNGTS on January 1, 2016.
- NGTL signed contracts for an additional 2.7 Bcf/d of new firm natural gas transportation service that will require a further $600 million expansion of the System for its 2018 Facilities program.


Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
500 km
200 mi
TC - 01 - 18 - 16

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		length	description	effective ownership
	Canadian pipelines			
1	NGTL System	24,544 km (15,251 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
2	Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%
4	Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
	U.S. pipelines			
5	ANR Pipeline	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
5a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
6	Bison	488 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
7	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
8	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. upper Midwest. We effectively own 66.6 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28 per cent interest in TC PipeLines, LP	66.6%
9	Iroquois	669 km (416 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%
10	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with a third-party pipeline on the California/Mexico border. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%
11	Northern Border	2,264 km (1,407 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 14 per cent of the system through our 28 per cent interest in TC PipeLines, LP	14%
12	Portland (PNGTS)	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. northeast. We effectively own 25.8 per cent of the system through the combination of 11.8 per cent direct ownership and our 28 per cent interest in TC PipeLines, LP. Prior to January 1, 2016 we had direct ownership of 61.7 per cent.	25.8%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 28 per cent of the system through our interest in TC PipeLines, LP	28%

		length	description	effective ownership
	U.S. pipelines			
14	TC Offshore[1]	958 km (595 miles)	Gathers and transports natural gas within the Gulf of Mexico with subsea pipeline and seven offshore platforms to connect in Louisiana with our ANR Pipeline system.	100%
	Mexican pipelines			
15	Guadalajara	315 km (196 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
16	Tamazunchale	365 km (227 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to El Sauz, Queretaro	100%
	Under construction			
17	Mazatlan Pipeline	413 km* (257 miles)	To deliver natural gas from El Oro to Mazatlan, Sinaloa in Mexico. Will connect to the Topolobampo Pipeline at El Oro	100%
18	Topolobampo Pipeline	530 km* (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
19	Tuxpan-Tula Pipeline	250 km* (155 miles)	The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to CFE combined-cycle power generating facilities in each of those jurisdictions as well as to the central and western regions of Mexico.	100%
	NGTL 2016/17 Facilities**	540 km* (336 miles)	An expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests received in 2014 on the NGTL System and expected to be completed between 2016 and 2018.	100%
	In development			
20	Coastal GasLink	670 km* (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
21	Prince Rupert Gas Transmission	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
22	North Montney Mainline	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project	100%
23	Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
24	Eastern Mainline Project	279 km* (173 miles)	Pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project.	100%
	NGTL 2018 Facilities**	88 km* (55 miles)	An expansion program comprised of multiple projects of 20- to 48-inch diameter pipelines, one new compressor unit and multiple meter stations to meet new incremental firm service requests received in 2015 on the NGTL System and expected to be completed in 2018.	100%

* Final pipe lengths are subject to changes during construction and/or final design considerations.
** Facilities are not shown on the map

1 As at December 31, 2015, TC Offshore was classified as Assets held for sale. See Significant Events for further information.

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Comparable depreciation and amortization is also a non-GAAP measure. See page 10 for more information on non-GAAP measures we use and page 108 for reconciliation to its GAAP equivalent.

year ended December 31 (millions of $)	2015	2014	2013
Comparable EBITDA	**3,477**	3,241	2,852
Comparable depreciation and amortization	**(1,132)**	(1,063)	(1,013)
Comparable EBIT	**2,345**	2,178	1,839
Specific items:			
TC Offshore loss on sale	**(125)**	—	—
Gas Pacifico/INNERGY gain on sale	**—**	9	—
NEB 2013 Decision – 2012	**—**	—	42
Segmented earnings	**2,220**	2,187	1,881

Natural Gas Pipelines segmented earnings in 2015 increased by $33 million compared to 2014 and included a $125 million before tax loss provision ($86 million after tax) as a result of a December 2015 agreement to sell TC Offshore, which is expected to close in early 2016. See Significant Events for more information. Segmented earnings in 2014 included $9 million related to the gain on sale of Gas Pacifico/INNERGY in November 2014 and, in 2013, included $42 million related to the 2012 impact of the NEB 2013 Decision. These amounts have been excluded from our calculation of comparable EBIT. Comparable EBIT and comparable EBITDA are discussed below.

year ended December 31 (millions of $)	2015	2014	2013
Canadian Pipelines			
Canadian Mainline	**1,230**	1,334	1,121
NGTL System	**934**	856	846
Foothills	**107**	106	114
Other Canadian pipelines[1]	**27**	22	26
Canadian Pipelines – comparable EBITDA	**2,298**	2,318	2,107
Comparable depreciation and amortization	**(845)**	(821)	(790)
Canadian Pipelines – comparable EBIT	**1,453**	1,497	1,317
U.S. and International Pipelines (US$)			
ANR	**232**	189	188
TC PipeLines, LP[1,2]	**106**	88	72
Great Lakes[3]	**63**	49	34
Other U.S. pipelines (Bison[4], GTN[5], Iroquois[1], Portland[6])	**84**	132	183
Mexico (Guadalajara, Tamazunchale)	**181**	160	100
International and other[1,7]	**4**	(10)	(4)
Non-controlling interests[8]	**292**	241	186
U.S. and International Pipelines – comparable EBITDA	**962**	849	759
Comparable depreciation and amortization	**(224)**	(219)	(217)
U.S. and International Pipelines – comparable EBIT	**738**	630	542
Foreign exchange impact	**206**	68	15
U.S. and International Pipelines – comparable EBIT (Cdn$)	**944**	698	557
Business Development comparable EBITDA and comparable EBIT	**(52)**	(17)	(35)
Natural Gas Pipelines – comparable EBIT	**2,345**	2,178	1,839
Summary			
Natural Gas Pipelines – comparable EBITDA	**3,477**	3,241	2,852
Comparable depreciation and amortization	**(1,132)**	(1,063)	(1,013)
Natural Gas Pipelines – comparable EBIT	**2,345**	2,178	1,839

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

2 Beginning in August 2014, TC PipeLines, LP began its at-the-market equity issuance program which, when utilized, decreases our ownership interest in TC PipeLines, LP. On October 1, 2014, we sold our remaining 30 per cent direct interest in Bison to TC PipeLines, LP. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. 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 interest of GTN, Bison and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of					
	December 31, 2015	April 1, 2015	October 1, 2014	January 1, 2014	July 1, 2013	May 22, 2013
TC PipeLines, LP	28.0	28.3	28.3	28.9	28.9	28.9
Effective ownership through TC PipeLines, LP:						
Bison	28.0	28.3	28.3	20.2	20.2	7.2
GTN	28.0	28.3	19.8	20.2	20.2	7.2
Great Lakes	13.0	13.1	13.1	13.4	13.4	13.4

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

4 Effective October 1, 2014 we have no direct ownership in Bison. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013.

5 Effective April 1, 2015 we have no direct ownership in GTN. Prior to that our direct ownership was 30 per cent effective July 1, 2013.

6 Represents our 61.7 per cent ownership interest.

7 Includes our share of the equity income from TransGas and Gas Pacifico/INNERGY as well as general and administration costs relating to our U.S. and International

Pipelines. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

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

Canadian Pipelines

year ended December 31 (millions of $)	2015	2014	2013
Net income			
Canadian Mainline – net income	**213**	300	361
Canadian Mainline – comparable earnings	**213**	300	277
NGTL System	**269**	241	243
Average investment base			
Canadian Mainline	**4,784**	5,690	5,841
NGTL System	**6,698**	6,236	5,938

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

In 2014, the Canadian Mainline operated under the NEB 2013 Decision for the years 2013-2017, which included an approved ROE of 11.5 per cent on deemed common equity of 40 per cent and an incentive mechanism based on total net revenues.

In 2015, the Canadian Mainline began operating under the NEB 2014 Decision which was approved by the NEB in November 2014 and superseded the NEB 2013 Decision. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 per cent to 11.5 per cent. This decision also included an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from us. Toll stabilization is achieved through the continued use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over the six-year fixed toll term.

Canadian Mainline's comparable earnings in 2015 decreased by $87 million compared to 2014 mainly due to a lower approved ROE on a lower average investment base, lower incentive earnings and a $20 million after-tax contribution from us resulting in a lower realized ROE of 11.15 per cent compared to the realized ROE of 13.18 per cent in 2014. The lower average investment base in 2015 was mainly due to the deferral of the 2014 net revenue surplus in the 2015 investment base.

Comparable earnings in 2014 were $23 million higher than 2013 because of higher incentive earnings partially offset by a lower average investment base. Net income of $361 million recorded in 2013 included $84 million related to the 2012 impact of the NEB 2013 Decision, which was excluded from comparable earnings.

Net income for the NGTL System was $28 million higher in 2015 compared to 2014 mainly due to a higher average investment base and OM&A incentive losses realized in 2014. Net income in 2014 was $2 million lower than 2013 due to the 2014 OM&A incentive losses realized partially offset by a higher average investment base. The 2015 NGTL Settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent and an annual cost-sharing mechanism for cost variances between actual and fixed OM&A costs. The 2013-2014 NGTL Settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent and fixed annual OM&A costs with any variance between actual and fixed OM&A accruing to us.

Comparable EBITDA and EBIT for the Canadian pipelines reflect the variances discussed above as well as variances in depreciation, financial charges and income tax which are substantially recovered in revenue on a flow-through basis and, therefore, do not have a significant impact on net income.

U.S. and International Pipelines

EBITDA for our U.S. operations is affected by contracted volume levels, actual volumes delivered and the rates charged, and the total cost of providing services.

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

Comparable EBITDA for the U.S. and International Pipelines was US$113 million higher in 2015 than 2014. This was due to the net effect of:

- higher ANR Southeast Mainline transportation revenue, incidental commodity sales and ANR's first quarter 2015 settlement with an owner of adjacent facilities for commercial interruption of ANR's service, partially offset by increased spending on ANR pipeline integrity work
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- lower contributions from other U.S. Pipelines due to ownership interests in GTN and Bison sold to TC PipeLines, LP in April 2015 and October 2014, respectively. These drop downs increased EBITDA from TC PipeLines, LP and also increased the partially offsetting non-controlling interests
- a stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

Comparable EBITDA for the U.S. and International Pipelines was US$90 million higher in 2014 than 2013. This was due to the net effect of:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher transportation revenue at Great Lakes mainly due to colder winter weather and increased demand
- lower contributions from GTN and Bison following the reductions in our effective ownership in each pipeline in July 2013 (GTN and Bison) and October 2014 (Bison)
- 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 was $69 million higher in 2015 compared to 2014 mainly because of a higher investment base for the NGTL System, depreciation for the completed Tamazunchale Extension and the effect of a stronger U.S. dollar. Depreciation and amortization was $50 million higher in 2014 than in 2013 mainly because of a higher investment base for the NGTL System, as well as the impact of the Mainline NEB 2013 Decision.

Business development

In 2015, business development expenses were $35 million higher than 2014 primarily due to increased business development activity related to our Mexico projects. Also in third quarter 2014, we recovered amounts from partners for 2013 Alaska Gasline Inducement Act costs. Business development expenses were $18 million lower in 2014 compared to 2013 mainly due to a change in scope on the Alaska project as well as the recovery discussed above. See page 44 for further discussion on Alaska.

OUTLOOK

Earnings

Canadian Pipelines

Net income for rate-regulated pipelines is affected by changes in investment base, ROE and regulated capital structure, and also by the terms of toll settlements or other toll proposals approved by the NEB.

In 2016, the Canadian Mainline will continue to operate under the terms of the NEB 2014 Decision. We expect Canadian Mainline 2016 earnings to be slightly lower than 2015 due to a declining investment base.

We expect the NGTL System investment base to continue to grow as we connect new natural gas supply in northeastern B.C. and western Alberta and respond to continued growth in market demand and that this will continue to have a positive impact on NGTL System earnings in 2016. The terms of the recently negotiated NGTL 2016-2017 Revenue Requirement Settlement generally include a continuation of the ROE, depreciation rates and incentive sharing mechanism as those established in the 2015 Revenue Requirement Settlement.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these pipelines to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

U.S. Pipelines

U.S. Pipeline earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end use customers in the form of competing natural gas pipelines and supply sources, in addition to broader conditions that might impact demand from certain customers or market segments. Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulators' decisions.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance.

ANR has secured new long term contracts and extended terms at maximum recourse rates for significant volumes originating from the Utica/Marcellus shale plays with contract start dates through late 2015 that resulted in increased revenues. On January 29th, 2016, ANR submitted a filing with the FERC under Section 4 of the Natural Gas Act seeking to increase its base rates. We anticipate that the proposed rates will take effect in third quarter 2016. These rates are subject to customer refund as a result of the rates ultimately approved by FERC, which is based on the outcome of the regulatory process or settlement negotiations with ANR's customers.

Also, Great Lakes, Northern Border and GTN have benefited from recent market conditions that increased the value of their services. We continue to seek opportunities to expand upon this success along with those opportunities associated with continued growth in end use markets for natural gas as we examine commercial, regulatory and operational changes to continue to optimize our pipelines' positions in response to positive developments in supply fundamentals.

Mexican Pipelines

Overall earnings from our Mexican pipelines are expected to increase in 2016 due to the addition of two new pipelines, Topolobampo and Mazatlan, which are expected to be placed in service in fourth quarter 2016. The 2016 earnings for our current operating assets in Mexico are expected to be consistent with 2015 earnings due to the nature of the long-term contracts underpinning our Mexican pipeline systems.

Capital spending

We spent a total of $2.7 billion in 2015 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend approximately $4 billion in 2016 primarily on the NGTL System expansion projects, ANR maintenance capital, the Tuxpan-Tula and Topolobampo pipelines in Mexico and Canadian Mainline capacity projects.

UNDERSTANDING THE NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipeline business builds, owns and operates a network of natural gas pipelines in North America that connects gas production to end use markets. The network includes pipelines that are buried underground and transport natural gas under high pressure, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline and meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations.

Our Major Pipeline Systems

The Natural Gas Pipelines map on page 30 shows our extensive pipeline network in North America that connects major supply sources and markets. Three major pipeline systems account for approximately 80 per cent of the total owned and operated pipe length. These systems are:

NGTL System: This is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. We believe we are very well positioned to connect growing supply in northeast B.C. and northwest Alberta and it is these two supply areas, along with growing demand for firm transportation in the oil sands area, that is driving our large capital program for new pipeline facilities on the NGTL System. The NGTL System is also very well positioned to connect WCSB supply to potential LNG export facilities on the Canadian west coast.

Canadian Mainline: This is a major pipeline that was originally designed as a long haul delivery system transporting supply from the WCSB basin across Canada to Ontario and Québec to deliver gas to downstream Canadian and U.S. markets. The Canadian Mainline continues this role, but is also transitioning to accommodate additional supply connections that are closer to the market served by this pipeline.

ANR System: This is the largest US-based gas pipeline asset we own and operate and is comparable in length to the Canadian Mainline. This pipeline system was originally designed predominantly to transport natural gas supply from the Gulf Coast and northern Texas areas northward to serve markets in the U.S. Midwest. With the large increase of supply from the U.S. Northeast region, the southeast leg of ANR is transitioning from a predominantly south to north system to a bi-directional system with more gas moving north to south.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the NEB in Canada, by the FERC in the U.S. and by the CRE in Mexico. The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow us to recover costs to operate the network by collecting tolls, or payments, for services. Costs of operating the systems include a return on our capital invested in the assets or rate base, as well as the recovery of the rate base over time through depreciation. Other costs recovered include OM&A costs, income and property taxes and interest on debt. The regulator reviews our costs to ensure they are reasonable and prudently incurred and approves tolls that provide us a reasonable opportunity to recover them.

Within their respective jurisdictions, the FERC and CRE approve maximum transportation rates. These rates are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. As the pipeline operator within these jurisdictions, we may negotiate lower rates with shippers.

Sometimes we enter into agreements or settlements with our shippers for tolls and cost recovery, which may include mutually beneficial performance incentives. The regulator must approve a settlement, including any performance incentives, for it to be put into effect.

Generally, Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year and recover or refund the variance between actual and expected revenues and costs in future years. The Canadian Mainline, however, operates under a fixed toll arrangement for its longer-term firm transportation services and has the flexibility to price its shorter-term and interruptible services in order to maximize its revenue. In addition, the NGTL System has recently reached a two-year revenue requirement settlement for 2016 and 2017 that remains subject to NEB approval.

The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection or refund of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines

at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the FERC may institute proceedings to lower tolls if they consider the return on the capital invested to be too high.

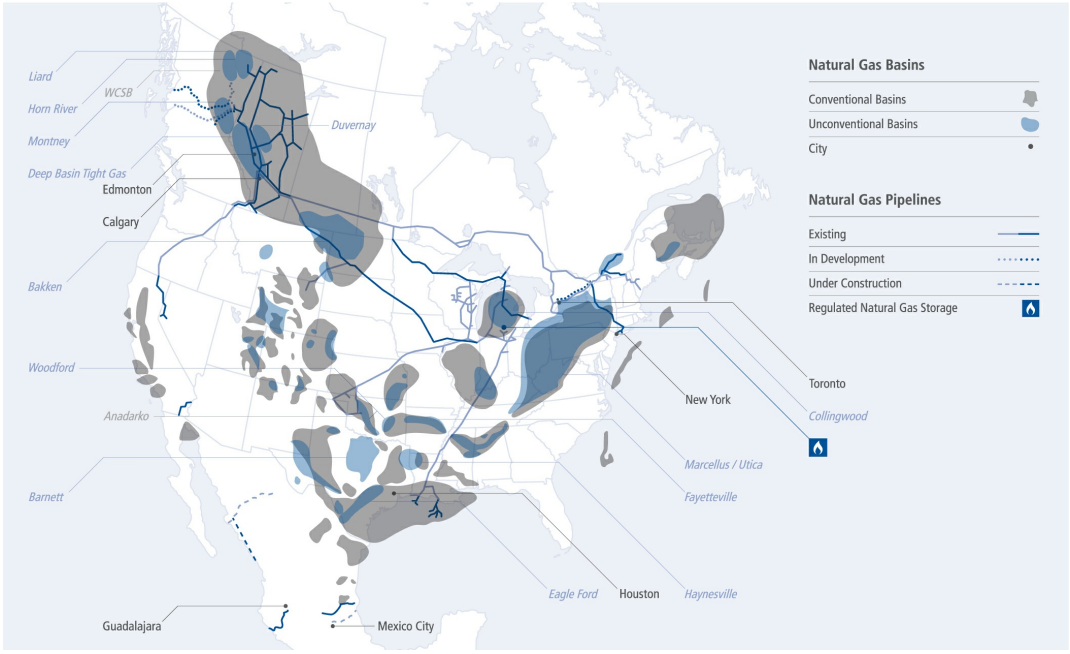
Our Mexican pipelines have approved tariffs, services and related rates. However, most of the contracts underpinning the construction and operation of the facilities in Mexico are long-term, fixed-rate contracts designed to recover the cost of our service.

Business environment and strategic priorities

The North American natural gas pipeline network has developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies as well as changes in the location of markets and level of demand.

We have a significant pipeline footprint in the WCSB and transport approximately 75 per cent of total WCSB production to markets within and outside of the basin. Our pipelines also source natural gas, to a lesser degree, from the other major basins including the Appalachian (Utica and Marcellus), Rockies, Williston, Haynesville, Fayetteville and Anadarko as well as the Gulf of Mexico.

North American Natural Gas Basins



Increasing supply

The WCSB spans almost all of Alberta and extends into B.C., Saskatchewan, Yukon and Northwest Territories and is Canada's primary source of natural gas supply. The WCSB is currently estimated to have 150 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of over 700 trillion cubic feet. The total recoverable WCSB resource base has recently more than quadrupled with the advent of technology that can economically access unconventional gas areas in the basin. After decreasing every year since 2007, production from the WCSB increased slightly in 2014 and 2015 to 14.7 Bcf/d. The Montney and Horn River shale play formations and the Liard basin in northeastern B.C. are part of the WCSB and have recently become a significant source of natural gas. We expect production from the Montney play that is currently 3 Bcf/d to grow to approximately 6 Bcf/d by 2020, depending on the economics of exploration and production compared to other, mainly U.S., sources and the progress of proposed B.C. west coast LNG exports.

The primary sources of natural gas in the U.S. are the U.S. shale areas, Gulf of Mexico and the Rockies. The U.S. shales are the biggest area of growth which we estimate will meet almost 50 per cent of the overall North American gas demand by 2020. The largest shale developments for natural gas are the Utica/Marcellus basins in the northeast U.S. These basins have grown from essentially no production prior to 2008 to over 18 Bcf/d at the end of 2015. They are forecast to grow to 25 Bcf/d by 2020. Other natural gas supply from shale in the U.S. includes the Haynesville, Barnett, Eagle Ford and Fayetteville plays.

The overall supply of natural gas in North America is forecast to increase significantly over the next decade (by almost 20 Bcf/d or 22 per cent by 2020) and is expected to continue to increase over the long term for several reasons:

- continued technological progress with horizontal drilling and multi-stage hydraulic fracturing or fracking. This is increasing the technically accessible resource base of existing basins and emerging regions, such as the Marcellus and Utica in the U.S. northeast and the Montney and Horn River areas in northeastern B.C.
- these technologies are also being applied to existing oil fields where further recovery of the resource is now possible. There is often associated gas discovered in the exploration and production of liquids-rich hydrocarbon basins (for example, the Bakken oil fields) which also contributes to an increase in the overall gas supply for North America.

The development of shale gas basins that are located close to existing markets, particularly in the northeast U.S., has led to an increase in the number of supply choices and is changing historical gas pipeline flow patterns, generally from long-haul to shorter haul pipelines. Along with our competitors, we have and continue to assess further opportunities to restructure our tolls and service offerings to capture this growing northeast supply and North American demand.

Growing northeast supply has had a positive impact for both the Mainline, with new proposed facilities in eastern Canada, and our ANR pipeline assets, with significant new long-term contracts for service. The increase in supply in northeastern B.C. and northwest Alberta has created opportunities for us to plan and build, subject to regulatory approval and positive final investment decisions (FID), new large pipeline infrastructure on the NGTL System to move the natural gas to markets, including proposed LNG exports and growing Alberta market demand.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which has supported increased demand for natural gas particularly in the following areas:

- natural gas-fired power generation
- petrochemical and industrial facilities
- the production of Alberta oil sands, although new greenfield projects that have not begun construction may be delayed in the current low oil price environment
- exports to Mexico to fuel new power generation facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets, which involves connecting natural gas supplies to new LNG export terminals which are proposed primarily along the west coast of B.C. and the U.S. Gulf of Mexico. Assuming the receipt of all necessary regulatory and other approvals, the proposed facilities along the west coast of B.C. are expected to become operational later this decade. The U.S. Gulf Coast also has several LNG export facilities in various stages of development or construction. LNG exports are expected to ramp up from this area, including one facility being commissioned to accommodate full deliveries in early 2016. The demand created by the addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

Commodity Prices

In general, the profitability of our gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and related pricing can have an indirect impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure. There is also a relationship between other fuel sources and their prices, including LNG export contracts which have historically been tied to the price of oil. In this current low oil price environment, the ability of gas producers to advance LNG projects that are tied to oil prices will be more challenging. On the other hand, low natural gas prices compete extremely well with coal-fired electric generation. In 2015, we have seen record levels of power generation with natural gas as the fuel source, particularly in the U.S.

More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. Development of technology for shale gas supply basins that are closer to markets historically served by long-haul pipelines has resulted in changes to flow patterns of existing natural gas pipeline infrastructure that includes reversing direction of flow and different distances of haul, particularly with the large development of U.S. northeast supply. Along with other pipelines, we have and continue to assess further opportunities to restructure our tolls and service offerings to capture this growing northeast supply and North American demand.

Strategic priorities

We are focused on capturing opportunities resulting from growing natural gas supply, and connecting new markets, while satisfying increasing demand for natural gas within existing markets. We are also focused on adapting our existing assets to the changing gas flow dynamics.

In 2016, we will continue to advance the planned conversion of portions of the Canadian Mainline from natural gas service to crude oil service. The Energy East Pipeline is a planned project, subject to regulatory approval, to convert approximately 3,000 km (1,864 miles) of the Canadian Mainline from the Alberta border to a point in eastern Ontario, southeast of Ottawa, to crude oil service. We announced in August 2015 that we had reached an agreement with eastern LDCs that ensures the net result of the pipeline asset transfer to Energy East and Eastern Mainline Project will provide gas consumers in Eastern Canada with sufficient natural gas transmission capacity and reduced natural gas transmission costs. We are also advancing new facilities in Eastern Canada to enable more supply into our system from sources that are closer to the end market.

We will continue to advance the previously announced 2016/2017 Facilities project on our NGTL System that is driven by contracts for approximately 4 Bcf/d of new firm service transportation requests as well as our new 2018 program that is underpinned by an additional 2.7 Bcf/d of new firm transportation service on the System.

Our ANR Pipeline has operated under the existing rate settlement for nearly 20 years. As a result of changes to traditional supply sources and markets, necessary operational changes, needed infrastructure updates, and evolving regulatory requirements that are driving required investment in facility maintenance, reliability and system integrity, along with an increase in operating costs, we are seeking to restate our transportation rates to appropriately recover our cost of providing service. Our preferred process to restate our rates is to reach a mutually beneficial outcome with our shippers through a settlement negotiation and that will be a focus area for us in 2016. In parallel to the settlement process, on January 29, 2016 ANR filed a Section 4 rate case with FERC.

We will also continue to pursue further connections to growth in supply and markets for our U.S. assets.

The drop down of our remaining U.S. natural gas pipeline assets into TC PipeLines, LP remains an important financing lever for us as we execute our capital growth program, subject to actual funding needs, market conditions, the relative attractiveness of alternate capital sources and the approvals of TC PipeLines LP's board and our board.

Our focus in Mexico in 2016 is to complete construction and bring into service the Mazatlan and Topolobampo pipelines and to begin permitting and construction of our recently awarded Tuxpan-Tula pipeline. We also remain focused on continuing to operate our existing facilities safely and reliably. We continue to be very interested in the further development of natural gas infrastructure in Mexico and will work to secure future projects that align with our strategic priorities.

SIGNIFICANT EVENTS

Canadian Regulated Pipelines

NGTL System

In 2015, we placed approximately $350 million of facilities in service. For 2016, the NGTL System continues to develop a further approximately $7.3 billion of new supply and demand facilities. We have approximately $2.3 billion of facilities that have received regulatory approval with approximately $450 million currently under construction. We have filed for approval for a further approximately $2.0 billion of facilities which are currently under regulatory review. Applications for approval to construct and operate an additional $3.0 billion of facilities have yet to be filed.

Included in our capital program described above is the recently announced2018 expansion of a further $600 million of facilities required on the NGTL System. The 2018 expansion includes multiple projects totaling approximately 88 km (55 miles) of 20- to 48-inch diameter pipeline, one new compressor, approximately 35 new and expanded meter stations and other associated facilities. Applications to construct and operate the various components of the 2018 expansion program will be filed with the NEB between second quarter and fourth quarter 2016. Subject to regulatory approvals, construction is expected to start in 2017, with all facilities expected to be in service in 2018.

North Montney Mainline

The North Montney Mainline is a pipeline project that will provide substantial new capacity on the NGTL System to meet the transportation requirements associated with rapidly increasing development of natural gas resources in the Montney supply basin in northeastern B.C. The project will connect Montney and other WCSB supply to both existing and new natural gas markets, including LNG markets.

The North Montney Mainline project will consist of two large diameter 42-inch pipeline sections, Aitken Creek and Kahta, totaling approximately 301 km (187 miles) in length, and associated metering facilities, valve sites and compression facilities. The project will also include an interconnection with our proposed Prince Rupert Gas Transmission Project (PRGT) to provide natural gas supply to the proposed Pacific NorthWest (PNW) LNG liquefaction and export facility near Prince Rupert, B.C. We expect to have the Aitken Creek and Kahta sections in service in 2017.

The NEB approved the $1.7 billion project in June 2015 subject to certain terms and conditions. Under one of these conditions, construction on the North Montney Mainline project can only begin after a positive FID has been made on the proposed PNW LNG project.

Merrick Mainline

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

The Merrick Mainline is a $1.9 billion project that will consist of approximately 260 kilometres (161 miles) of 48-inch diameter pipe.

Canadian Mainline

Energy East and the Eastern Mainline Project

In October 2014, an application was filed with the NEB for the Energy East project and to transfer a portion of the Canadian Mainline from natural gas service to crude oil service. An application was also filed for the Eastern Mainline Project, consisting of new gas facilities in southeastern Ontario required as a result of the proposed transfer of Canadian Mainline assets to crude oil service for the Energy East project.

Application amendments were filed in December 2015 that reflect the agreement we announced in August 2015 with eastern LDCs resolving their issues with Energy East and the Eastern Mainline Project. The agreement provides gas consumers in eastern Canada with sufficient natural gas transmission capacity and provides for reduced natural gas transmission costs.

The Eastern Mainline Project capital cost is now estimated to be $2.0 billion with the increase in the cost estimate due to the revised project scope resulting from the LDC agreement and updated cost estimates.

The Eastern Mainline Project is conditioned on the approval and construction of the Energy East pipeline. On January 27, 2016, the Canadian federal government announced interim measures for its review of the Energy East pipeline project. The government announced it will undertake additional consultations with aboriginal groups, help facilitate expanded public input into the NEB, and assess upstream GHG emissions associated with the project. The government will seek a six month extension to the NEB's legislative review and a three month extension to the legislative time limit for the government's decision. We are reviewing these changes and will assess the impacts to the Eastern Mainline Project.

Other Canadian Mainline Expansions

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

U.S. Pipelines

ANR Section 4 Rate Case

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

Sale of GTN and PNGTS to TC PipeLines, LP

In April 2015, we closed the sale of our remaining 30 per cent interest in GTN to TC PipeLines, LP, for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

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

TC Offshore

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

Mexican Pipelines

Topolobampo and Mazatlan Pipelines

The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and a cost of US$1 billion that will deliver gas to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico. The Mazatlan project is a 413 km (257 miles), 24-inch pipeline running from El Oro to Mazatlan within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million. Both projects are supported by 25-year contracts with the CFE and are in their final construction stages with expected in-service dates in late 2016.

Tuxpan-Tula Pipeline

In November 2015, we were awarded the contract to build, own and operate the US$500 million, 36 inch, 250 km (155 mile) Tuxpan-Tula pipeline with a contracted capacity of 886 MMcf/d for 25 years with the CFE. The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to each of those jurisdictions as well as the central region of Mexico. The pipeline will serve new power generating facilities as well as existing power plants that plan to switch from fuel oil to natural gas as their base fuel. Physical construction is expected to begin in 2016 with a planned in-service date in fourth quarter 2017.

LNG Pipeline Projects

Prince Rupert Gas Transmission

In June 2015, PNW LNG announced a positive FID for its proposed liquefaction and export facility, subject to two conditions. The first condition, approval by the Legislative Assembly of B.C. of a Project Development Agreement between PNW LNG and the Province of B.C., was satisfied in July 2015. The second condition is a positive regulatory decision on PNW LNG's environmental assessment by the Government of Canada, which has not yet been received.

In third quarter 2015, we received all remaining permits from the B.C. Oil and Gas Commission (BC OGC) which completes the eleven permits required to build and operate PRGT. Environmental permits for the project were received in November 2014 from the B.C. Environmental Assessment Office (BC EAO). With these permits, PRGT has all of the primary regulatory permits required for the project.

We remain on target to begin construction following confirmation of a FID by PNW LNG. The in-service date for PRGT is estimated to be 2020 but will be aligned with PNW LNG's liquefaction facility timeline.

We are continuing our engagement with Aboriginal groups and have now signed project agreements with ten First Nation groups along the pipeline route. Project agreements outline financial and other benefits and commitments that will be provided to each First Nation for as long as the project is in service.

PRGT is a 900 km (559 mile) natural gas pipeline that will deliver gas from the Montney producing region at an expected interconnect on the NGTL System near Fort St. John, B.C. to PNW LNG's proposed LNG facility near Prince Rupert, B.C. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.

Coastal GasLink

We are continuing our engagement with Aboriginal groups along our pipeline route and have now announced long-term project agreements with eleven First Nations. These project agreements outline financial and other benefits and commitments that will be provided to each First Nation for as long as the pipeline remains in service.

We also continue to engage with stakeholders along the pipeline route and are progressing detailed engineering and construction planning work to refine the capital cost estimate. In response to feedback received, we have applied for a minor route amendment to the BC EAO in order to provide an option in the area of concern. It is anticipated that approval for this route amendment will be received in first quarter 2016. We have received eight of ten pipeline and facilities permits from the BC OGC and anticipate receiving the remaining two permits in first quarter 2016. With these permits, Coastal GasLink will hold all of the required primary regulatory permits for the project.

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

Coastal GasLink is a 670 km (416 mile) pipeline that will deliver natural gas from the Dawson Creek, BC area, to the LNG Canada's proposed gas liquefaction facility near Kitimat, BC.

Alaska LNG Project

On November 24, 2015, we sold our interest in the Alaska LNG project to the State of Alaska. The proceeds of US$65 million from this sale provide a full recovery of costs incurred to advance the project since January 1, 2014 including a carrying charge. With this sale, our involvement in developing a pipeline system for commercializing Alaska North Slope natural gas ceases.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 94 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks and financial risks.

WCSB supply for downstream connecting pipelines

Many of our North American natural gas pipelines and transmission infrastructure assets depend largely on supply from the WCSB. We continue to monitor any changes in our customer's gas production plans and how these changes may impact our existing assets and new project schedules. There is competition for this supply from several pipelines within the basin. An overall decrease in production and/or competing demand for supply could impact throughput on WCSB connected pipelines that, in turn, could impact overall revenues generated. The WCSB has considerable reserves, but the amount actually produced depends on many variables, including the price of natural gas, basin-on-basin competition, downstream pipeline tolls, demand within the basin and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines and impact revenue. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering alternative transportation services at prices that are acceptable to the market.

Competition for greenfield expansion

We face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold. Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Renewal of expiring contracts and the opportunity to charge and collect a toll that the market accepts depends on the overall demand for transportation service. A change in the level of demand for our pipeline transportation services could impact revenues.

Commodity Prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure. As well, sustained low gas prices could impact our shippers' financial situation and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions by regulators can have an impact on the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable and therefore could impact revenues and the opportunity to further invest capital in our systems. There is also risk of a regulator disallowing a portion of our prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects, including the time it takes to receive a decision, could be slowed or unfavorable due to the influence from the evolving role of activists and their impact on public opinion and government policy related to natural gas pipeline infrastructure development.

Increased scrutiny of operating processes by the regulator or other enforcing agencies has the potential to increase operating costs. There is a risk of an impact to income if these costs are not fully recoverable.

We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business. We also work closely with our stakeholders in the development of rate, facility and tariff applications and negotiated settlements, where possible.

Construction and Operations

Constructing and operating our pipelines to ensure transportation services are provided safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impacting our throughput capacity and may result in reduced revenue and can affect corporate reputation as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, hiring third party inspectors during construction, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use pipeline inspection equipment to regularly check the integrity of our pipelines, and repair or replace sections whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Liquids Pipelines

Our existing liquids pipeline infrastructure connects Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S Gulf Coast. Our proposed future pipeline infrastructure would also connect Canadian and U.S. crude oil supplies to refining markets in eastern Canada and overseas export markets, and expand capacity for Canadian and U.S. crude oil to access U.S. markets. We will also pursue enhancing our transportation service offerings to other areas of the liquids pipelines business value chain.

Strategy at a glance

Our focus is on accessing and delivering growing North American liquids supply to key markets by expanding our liquids pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to the market.

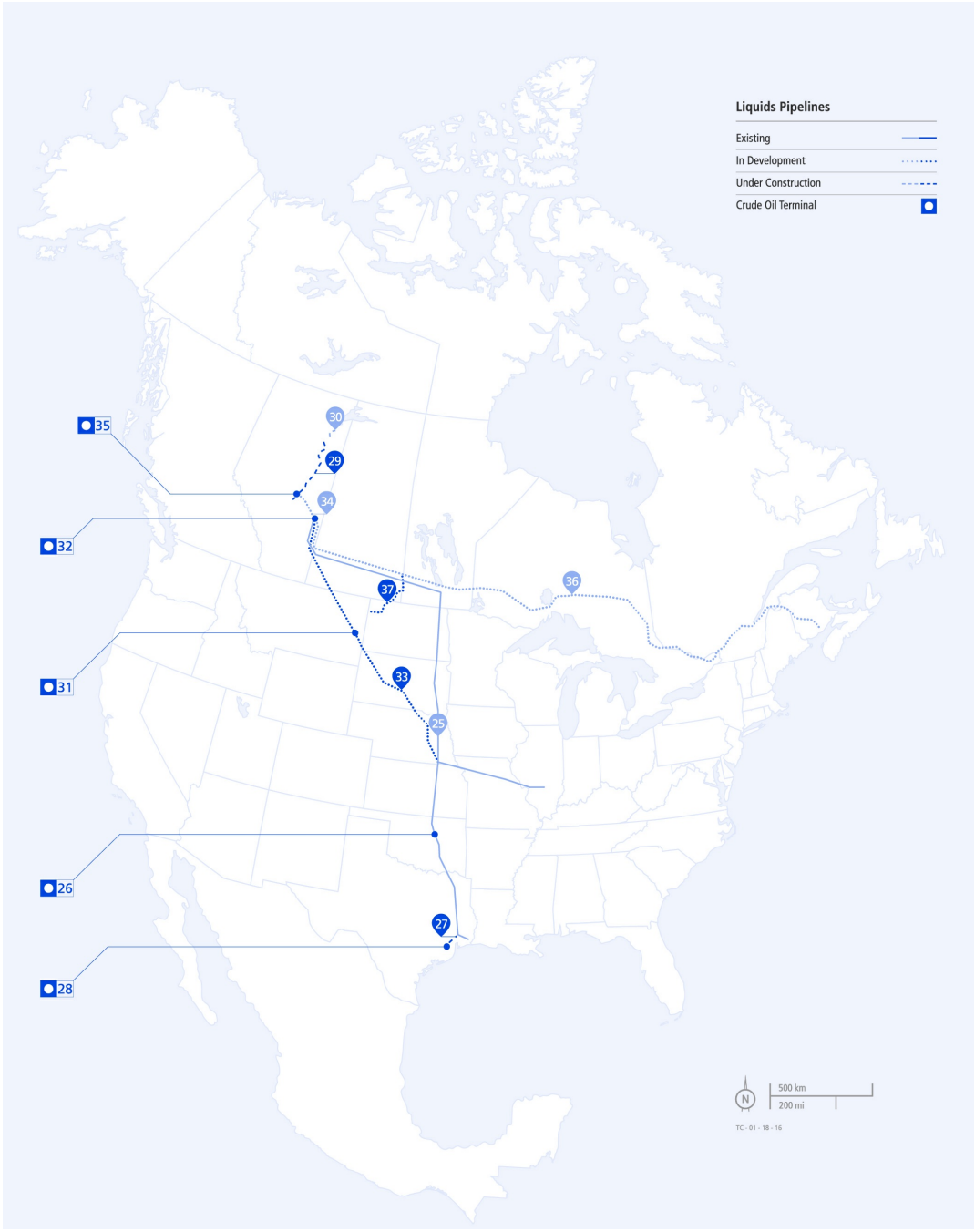
Although crude oil production growth is currently slowing as a result of slow demand growth, we are focused on maximizing the value from our current operating assets, securing organic growth around these assets, identifying acquisition opportunities in the current lower crude oil price environment and positioning our business development activities to capture opportunities when the environment recovers.

We are also expanding transportation service offerings to other areas of the liquids pipelines business value chain such as condensate transportation or ancillary services such as short and long term storage of liquids and liquids marketing, which complement our pipeline transportation infrastructure.

Continued development and construction of our proposed infrastructure projects will provide North America with a crucial liquids transportation network to transport growing supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.

Highlights from 2015

- Increased average throughput on Keystone Pipeline by 30,000 Bbl/d and increased long term contracts to 545,000 Bbl/d
- Finalized definitive agreements with Magellan Midstream Partners L.P. (Magellan), to jointly develop a connection between our Houston Tank Terminal and the Magellan delivery system enhancing our crude oil infrastructure connectivity to Houston and Texas City area refineries and terminals
- Finalized definitive agreements between Keyera Corp. and our Grand Rapids pipeline to enable Alberta oil sands producers to gain access to a reliable and cost effective source of diluent
- Created a liquids marketing business to expand our service offerings to other areas of the liquids pipelines business value chain. Marketing transactions will commence in 2016
- Throughout 2015, the Keystone XL cross border permit application experienced multiple delays from the DOS and was ultimately denied. We have launched legal and NAFTA challenges in response to the denial. We remain supportive of Keystone XL and are reviewing our options which include filing a new U.S. Presidential permit application
- Achieved significant construction progress on our regional Alberta projects, the Grand Rapids and Northern Courier pipeline systems
- Filed an amendment to Energy East's existing application with the NEB that adjusts the proposed route, scope and capital cost of the Energy East pipeline project based on extensive landowner, environmental, community and customer input


Liquids Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
35
30
29
34
32
36
37
31
33
25
26
27
28
500 km
200 mi
TC - 01 - 18 - 16

We are the operator of all of the following pipelines and properties.

	length	description	ownership
Liquids pipelines			
25 Keystone Pipeline System	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka Illinois, Cushing, Oklahoma, and Port Arthur, Texas	100%
26 Cushing Marketlink and Terminal		Terminal and pipeline facilities to transport crude oil from the market hub at Cushing, Oklahoma to the Port Arthur, Texas refining market on facilities that form part of the Keystone Pipeline System	100%
Under construction			
27 Houston Lateral and 28 Houston Terminal	77 km (48 miles)	To extend the Keystone Pipeline System to the Houston, Texas refining market	100%
29 Grand Rapids Pipeline	460 km (287 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland, Alberta market region	50%
30 Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
In development			
31 Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
32 Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
33 Keystone XL	1,897 km (1,179 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
34 Heartland Pipeline and 35 TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
36 Energy East Pipeline	4,600 km (2,850 miles)	To transport crude oil from western Canada to eastern Canadian refineries and export markets	100%
37 Upland Pipeline	460 km (285 miles)	To transport crude oil from, and between, multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan	100%

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Comparable depreciation and amortization is also a non-GAAP measure. See page 10 for more information on non-GAAP measures we use and page 108 for reconciliation to its GAAP equivalent.

year ended December 31 (millions of $)	2015	2014	2013
Comparable EBITDA	**1,322**	1,059	752
Comparable depreciation and amortization	**(266)**	(216)	(149)
Comparable EBIT	**1,056**	843	603
Specific item:			
Keystone XL impairment charge	**(3,686)**	—	—
Segmented (loss)/earnings	**(2,630)**	843	603

Liquids Pipelines segmented earnings decreased by $3,473 million to a segmented loss of $2,630 million in 2015 compared to 2014. The segmented loss included a $3,686 million pre-tax impairment charge related to Keystone XL and related projects. See Significant Events on page 54 and Critical accounting estimates on page 101 for more information. This amount has been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	2015	2014	2013
Keystone Pipeline System	**1,345**	1,073	766
Liquids Pipelines Business Development	**(23)**	(14)	(14)
Liquids Pipelines – comparable EBITDA	**1,322**	1,059	752
Comparable depreciation and amortization	**(266)**	(216)	(149)
Liquids Pipelines – comparable EBIT	**1,056**	843	603
Comparable EBIT denominated as follows:			
Canadian dollars	**236**	215	201
U.S. dollars	**640**	570	389
Foreign exchange impact	**180**	58	13
Liquids Pipelines – comparable EBIT	**1,056**	843	603

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $272 million higher this year than in 2014. This increase was primarily due to:

- higher volumes
- incremental earnings from the Keystone 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.

Comparable EBITDA for the Keystone Pipeline System was $307 million higher in 2014 than in 2013. This increase was primarily due to:

- incremental earnings from the Keystone 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.

Comparable depreciation and amortization

Comparable depreciation and amortization was$50 million higher in 2015 than in 2014 mainly due to the effect of a stronger U.S. dollar.Comparable depreciation and amortization was $67 million higher in 2014 than in 2013 mainly due to the Keystone Gulf Coast extension being placed in service.

OUTLOOK

Earnings

Excluding specified items, our 2016 earnings are expected to be slightly lower than our 2015 earnings due to short-term contracts expiring on Cushing Marketlink and weakened market conditions related to the lower crude oil price environment. Following our Keystone XL impairment charge, future expenditures on the project will be expensed pending further advancement of this project and we have ceased capitalizing interest on the project effective November 6, 2015, the date of the Presidential permit denial.

Over time, we expect Liquids Pipelines' earnings to increase as projects currently under construction and in development are placed in service.

Capital spending

We spent a total of $1.3 billion in 2015 on capital spending in Liquids Pipelines. We expect to spend approximately $1.2 billion on capital spending and equity investments in 2016, primarily on Grand Rapids Phase 1, Northern Courier and Energy East.

UNDERSTANDING THE LIQUIDS PIPELINES BUSINESS

Our liquids business currently consists of pipelines which efficiently move crude oil from major supply sources to markets where crude oil can be refined into various petroleum products and ancillary services such as short and long term storage of liquids. We have established a liquids marketing business to expand into other areas of the liquids business value chain. The Keystone Pipeline System, our largest liquids pipelines asset, moves approximately 20 per cent of western Canadian crude oil exports to key refining markets in the U.S. Mid-West and the Gulf Coast and has transported over 1.1 billion barrels of crude oil since operations began in 2010.

We generate earnings from our liquids business mainly by providing pipeline capacity to shippers supported by long term contracts with fixed monthly payments that are not linked to actual throughput volumes or to the price of the commodity. Uncontracted capacity is offered to the market on a spot basis which provides opportunities to generate incremental earnings.

The terms of service and fixed monthly payments are determined by transportation service arrangements negotiated with shippers. These long term arrangements provide for the recovery of costs we incur to construct and operate the system.

Business environment and strategic priorities

Over the past decade, North American crude oil production has increased significantly. However, slowing global demand combined with OPEC's market share strategy of increased production has resulted in a current global oversupply situation, which continues to put downward pressure on crude oil prices. Supply from high cost producers is expected to decrease in this lower price environment throughout the course of the year while supply and demand are expected to evolve to a more balanced position towards the end of the year.

Our liquids pipelines business is well positioned to endure the impact of short term commodity price fluctuations and supply adjustments. Our existing operations and development projects are supported by long term contracts where we have agreed to provide pipeline capacity to our customers in exchange for fixed monthly payments. The cyclical supply and demand nature of commodities and their price movements can have a secondary impact on our business where our shippers may choose to accelerate or delay certain new projects. This can impact the timing for the demand of transportation services and/or new liquids infrastructure.

We continue to advance a number of growth opportunities in the near term and will closely monitor the market place for strategic asset acquisition opportunities. Commodity price fluctuations are a normal part of the business cycle. Longer-term, we expect global demand for crude oil will continue to grow, ultimately resulting in continued growth in North American crude oil supply production and demand for new pipeline infrastructure. Our growing position in the liquids transportation business is creating a significant platform to capture these future growth opportunities.

Supply outlook

Canada

Alberta produces the majority of the crude oil in the WCSB which is the primary source of crude oil supply for the Keystone Pipeline System. In its *2015 Crude Oil Forecast, Markets and Transportation* report, the Canadian Association of Petroleum Producers (CAPP) estimates 2016 WCSB crude oil production will reach 1.3 million Bbl/d of conventional crude oil and condensate and 2.5 million Bbl/d of oil sands crude oil, for a total of approximately 3.8 million Bbl/d. The report forecasts WCSB crude oil production will increase to 4.4 million Bbl/d by 2020 and to 5.2 million Bbl/d by 2030. Even in the current challenging price environment, CAPP estimates current projects that are either in advanced stages of development or construction will add nearly 720,000 Bbl/d of WCSB supply between 2016 and 2020.

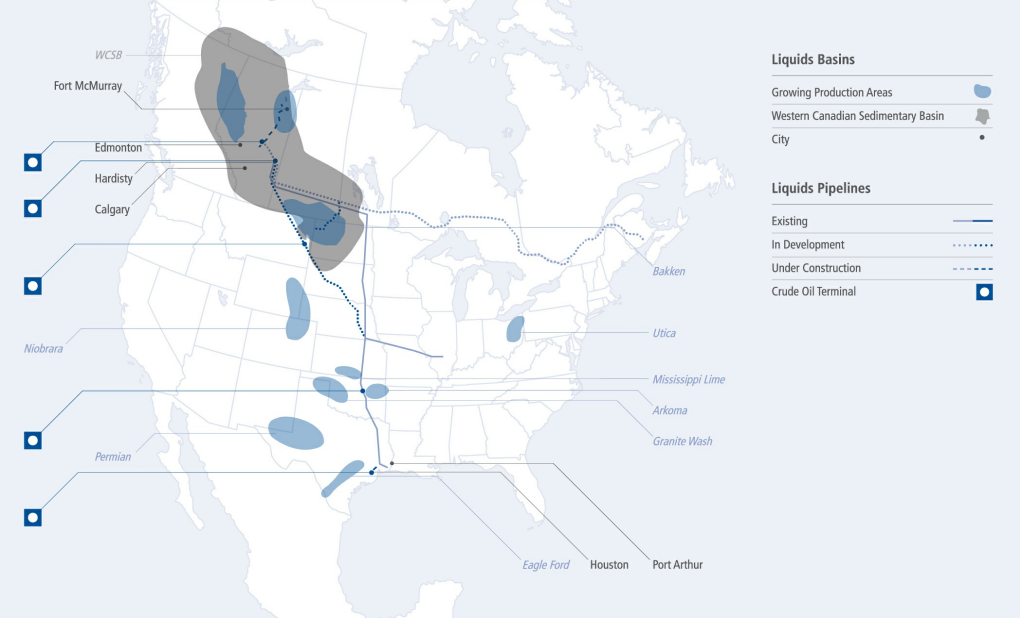
According to the May 2015 *Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015-2024*, the Alberta Energy Regulator (AER) estimates there is approximately 166 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta. Oil sands projects have a long reserve life. In its 2014 *Responsible Canadian Energy* report, CAPP estimates a typical oil sands mine has a 25 to 50 year lifespan, while an in-situ operation will run 10 to 15 years on average. This longevity aligns with the producer's desire to secure long term connectivity of their reserves to market. The Keystone Pipeline System, as well as projects under development such as the proposed Energy East Pipeline, are underpinned by long term contracts.

In November 2015, the Alberta Government developed a Climate Leadership Plan which includes phasing out of coal-generated electricity, implementing a new carbon price on GHG emissions, capping oil sands emissions at a maximum of 100 Megatonnes per year and reducing methane emissions. While details on this plan are forthcoming, it is anticipated that this plan would still allow for significant oil sands supply growth and would support future development of pipeline infrastructure to connect WCSB crude oil supply to markets.

U.S.

The U.S. Energy Information Administration (EIA) forecasts over 1.0 million Bbl/d of U.S. production growth from 2015 to 2020, peaking at 10.6 million Bbl/d by 2020. Higher production volumes result mainly from technological advancements in the development of shale oil production. EIA forecasts shale oil production peaking at approximately 5.6 million Bbl/d by 2020 and declining after 2022.

North American Liquids Basins



U.S. shale oil supply growth originates primarily from the Williston basin in North Dakota and Montana, the Permian basin in south Texas and Woodford shale area of the Arkoma basin in Oklahoma. These shale production areas also represent some of the sources of crude oil supply for our Cushing Marketlink system.

The growth in U.S. production has contributed to increased crude oil supply at the Cushing, Oklahoma market hub and has resulted in increased demand for additional pipeline capacity between Cushing, Oklahoma and the U.S. Gulf Coast refining market. Our Cushing Marketlink system, with connectivity to Houston and Port Arthur, Texas and Lake Charles, Louisiana refining markets, is well positioned to transport this growing supply.

Even with growth in U.S. crude oil production, which displaced foreign light imports from countries such as Nigeria and Saudi Arabia, the EIA report predicts the U.S. will remain a net importer of crude oil, importing 7.6 million Bbl/d into 2040. U.S. Gulf Coast refineries are mainly configured to process heavy and medium crude oil and cannot easily switch to processing light shale oil in large quantities without significant capital investments. U.S. Gulf Coast refineries currently require approximately 3.2 million Bbl/d of heavy and medium crude oil, and the level of demand is not expected to change significantly in the near or longer term. The Keystone Pipeline System is well positioned to deliver Canadian crude oil to this significant market.

The U.S. government recently lifted the 40 year ban on crude oil exports in December 2015 which removed the Federal Government restrictions on the export of crude oil. The decision is expected to help draw the supply from U.S. producing regions, including Cushing, Oklahoma, to tidewater and we anticipate seeing an increase in demand for coastal storage and export terminal facilities. Our Houston Lateral and Terminal is well positioned to capture the growing demand in this market.

Strategic priorities

We are focused on advancing our current portfolio of commercially secured projects to connect growing Canadian and U.S. crude oil supply to key markets, maximizing the value from our current operating assets, identifying acquisition opportunities and expanding across our liquids pipelines business value chain.

We continue to extend our Keystone Pipeline System’s access in the U.S. Gulf Coast market to over 4.5 million Bbl/d of regional refinery centres in Houston and Port Arthur, Texas and Lake Charles, Louisiana. Expanding the Keystone Pipeline System’s market access reach is expected to enhance both short and long haul volumes. Our joint venture with Magellan Midstream Partners, a connection between our Houston Lateral and Terminal and Magellan's Houston and Texas City, Texas delivery system, will enhance our crude oil connectivity in the Houston area. In 2015, we agreed to build a lateral to the CITGO Petroleum (CITGO) Sour Lake, Texas terminal which supplies the Lake Charles, Louisiana marketplace.

Securing regulatory approval for our $15.7 billion Energy East pipeline remains a key priority. In late 2015, we filed an amendment to the existing project application with the NEB that adjusts the proposed route, scope and capital cost of the project reflecting refinements and scope changes including the removal of the port in Québec. The project will continue to serve the three eastern Canadian refineries along the route in Montréal and Québec City, Québec and Saint John, New Brunswick.

Within Alberta, we are leveraging our extensive natural gas pipeline footprint and experience to develop a regional liquids pipelines business. Growth in oil sands production is driving the need for new intra-Alberta pipelines, like our 50 per cent interest in the Grand Rapids Pipeline, that can move crude oil production from the source to market hubs at Edmonton/Heartland and Hardisty, Alberta as well as diluent from Edmonton/Heartland region to the production area in northern Alberta. Our joint venture with Keyera Corp. will enhance our ability to access a reliable and cost effective source of diluent for the Grand Rapids Pipeline. In addition, our Northern Courier Pipeline will facilitate movements from new oil sands mine supply to market. When supported by market conditions, the Heartland Pipeline and TC Terminals and Keystone Hardisty Terminal projects will support these market hubs which will allow shippers to connect with the Keystone Pipeline System, Energy East Pipeline and other pipelines that transport crude oil outside of Alberta and ultimately provide our customers with a contiguous seamless path from production to market.

We have created a liquids marketing business which will provide incremental revenue by entering into short- or long-term pipeline or storage terminal capacity contracts, primarily on our assets, increasing the utilization of those assets and earning the market value of the capacity.

In this challenging crude oil price environment, we will closely monitor the market place for strategic asset acquisitions to enhance our system connectivity or expand our footprint within North America. We remain disciplined in our approach and will position our business development activities strategically to capture the opportunities as the business environment recovers.

SIGNIFICANT EVENTS

Keystone Pipeline System

In fourth quarter 2015, we secured additional long term contracts bringing our total contract position up to 545,000 Bbl/d. By the end of 2015, the Keystone Pipeline System had delivered more than 1.1 billion barrels of crude oil to U.S. markets since it began operating in 2010.

CITGO Sour Lake Pipeline

In 2015, we entered into an agreement with CITGO to construct a US$65 million pipeline connection between the Keystone Pipeline System to provide access to CITGO's Sour Lake, Texas terminal, which supplies their 425,000 Bbl/d Lake Charles, Louisiana refinery. The connection is targeted to be operational in fourth quarter 2016.

Houston Lateral and Terminal

Construction continues on the Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in second quarter 2016.

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

Keystone XL

The decision on the Keystone XL permit application was delayed throughout 2015 by the DOS and was ultimately denied in November 2015.

At December 31, 2015, as a result of the denial of the Presidential permit, we evaluated our investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after-tax). The impairment charge was based on the excess of the carrying value of $4.3 billion over the fair value of $621 million, which includes $93 million fair value for Keystone Hardisty Terminal. The Keystone Hardisty Terminal remains on hold with an estimated in-service date to be driven by market need. The calculation of this impairment is discussed further in the Critical accounting estimates section on page 101.

In November 2015, we withdrew our application to the Nebraska Public Service Commission for approval of the route for Keystone XL in the state. The application was initially filed in October 2015. The withdrawal was made without prejudice to potentially refile if we elect to pursue the project.

On January 5, 2016, the South Dakota Public Utility Commission accepted Keystone's certification that it continues to comply with the conditions in its existing 2010 permit authority in the state.

On January 6, 2016, we filed a Notice of Intent to initiate a claim under Chapter 11 of the NAFTA in response to the U.S. Administration's decision to deny a Presidential permit for the Keystone XL Pipeline on the basis that the denial was arbitrary and unjustified. Through the NAFTA claim, we are seeking to recover more than US$15 billion in costs and damages that we estimated to have suffered as a result of the U.S. Administration's breach of its NAFTA obligations. This litigation is in a preliminary stage and the likelihood of success and resulting impact on our financial position or results of operation is unknown at this time.

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

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

Energy East Pipeline

In April 2015, we announced that the proposed marine terminal and associated tank terminal in Cacouna, Québec will not be built as a result of the recommended reclassification of the beluga whale, indigenous to the site, as an endangered species. Following consultation of stakeholders and shippers, we announced in November 2015 the intention to amend the Energy East application to remove a port in Québec and proceed with a single marine terminal in Saint John, New Brunswick. On December 17, 2015, we filed an amendment to the existing project application with the NEB that adjusted the proposed route, scope and capital cost of the project reflecting refinement and scope change including the removal of the port in Québec. The project will continue to serve the three eastern Canadian refineries along the route in Montréal and Québec City, Québec and Saint John, New Brunswick.

Changes to the project schedule and scope, as reflected in the amendment, have contributed to a new project capital cost of $15.7 billion, excluding the transfer of Canadian Mainline natural gas assets. Of the total long-term shipping commitments for the project of 995,000 bbl/d, with an average term of 19 years, 725,000 bbl/d designate the Québec refineries or Saint John, New Brunswick as delivery points. A total of 270,000 bbl/d remains under contract for delivery to the Québec market, including a Québec based marine terminal, and without a Saint John, New Brunswick delivery point. Discussions are ongoing with those shippers to remove the Québec marine terminal from the terms of their shipping contracts.

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

Northern Courier Pipeline

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

Heartland Pipeline and TC Terminals

The Heartland Pipeline is a crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta. TC Terminals is a terminal facility in the Heartland industrial area north of Edmonton, Alberta located at the start of the Heartland Pipeline. Construction has been delayed and the in-service date for the projects will be determined and aligned with industry and our customer's requirements.

Grand Rapids Pipeline

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

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

In August 2015, we announced a joint venture between Grand Rapids and Keyera Corp. for provision of diluent transportation service on the 20-inch pipeline between Edmonton and Fort Saskatchewan, Alberta, which is anticipated to be in service in the second half of 2017. The joint venture will be incorporated into phase one of Grand Rapids and it will provide enhanced diluent supply alternatives to our shippers.

Upland Pipeline

In April 2015, we filed an application to obtain a U.S. Presidential permit for the Upland Pipeline. The pipeline will provide crude oil transportation from and between multiple points in North Dakota and interconnect with the Energy East Pipeline System at Moosomin, Saskatchewan. Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2020. The commercial contracts we have executed for Upland Pipeline are conditioned on the Energy East project proceeding. We are reviewing the Canadian federal government's interim measures for pipeline reviews and will assess the impact to Upland Pipeline.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 94 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Operational

Optimizing and maintaining availability of our liquids pipelines is essential to the success of our Liquids Pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

While the majority of the power costs to operate the Keystone Pipeline System are passed through to our shippers, a portion of our volume is moved under an all-in fixed toll structure where we are exposed to changing power costs which may impact our earnings.

Regulatory and Government

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation and financial performance of our liquids pipelines. Public opinion about crude oil development and production may also have an adverse impact on the regulatory process. In conjunction with this, there are some individuals and interest groups that are expressing their opposition to crude oil production by lobbying against the construction of liquids pipelines. Lastly, changing environmental requirements or revisions to current regulatory process may impact the timing to obtain permit approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government developments and decisions to determine their possible impact on our liquids pipelines business and by working closely with our stakeholders in the development and operation of the assets.

Execution, capital costs and permitting

We make substantial capital commitments in large infrastructure projects based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers and while we carefully consider the expected cost of our capital projects, under some contracts we bear greater capital cost risk which may impact our return on these projects. Our capital projects are also subject to permitting risk which may result in construction delays, increased capital cost and, potentially, reduced investment returns.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. Lower crude oil prices could mean producers may curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors would negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American liquids transportation market to transport growing crude oil and condensate supplies between key North American producing regions and refining and export markets, we face competition from other midstream companies which also seek to transport these crude oil and condensate supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Liquids marketing

The liquids marketing business will generate revenue by capitalizing on asset utilization opportunities by entering into short-term or long-term pipeline or storage terminal capacity contracts.

Volatility in commodity prices and changing market conditions could impact the value of those capacity contracts. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management polices which are described in Other information - Risks and risk management.

Energy

Our Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta.

We own, control or are developing approximately 13,100 MW of generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our power business in the U.S. is located in New York, New England, Pennsylvania and Arizona. The assets are largely supported by long-term contracts and some represent low-cost baseload generation, while others are essential to providing capacity to the area in which they are located.

We conduct wholesale and retail electricity marketing and trading throughout North America from our offices in Alberta, Ontario and Massachusetts to actively manage our commodity exposure and provide higher returns.

We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province. When combined with the regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment), we provide over 350 Bcf of natural gas storage and related services.

Strategy at a glance

Build upon our diverse portfolio of contracted and low cost power generation assets located in core North American markets, while maximizing the value of our existing investments through safe and reliable operations

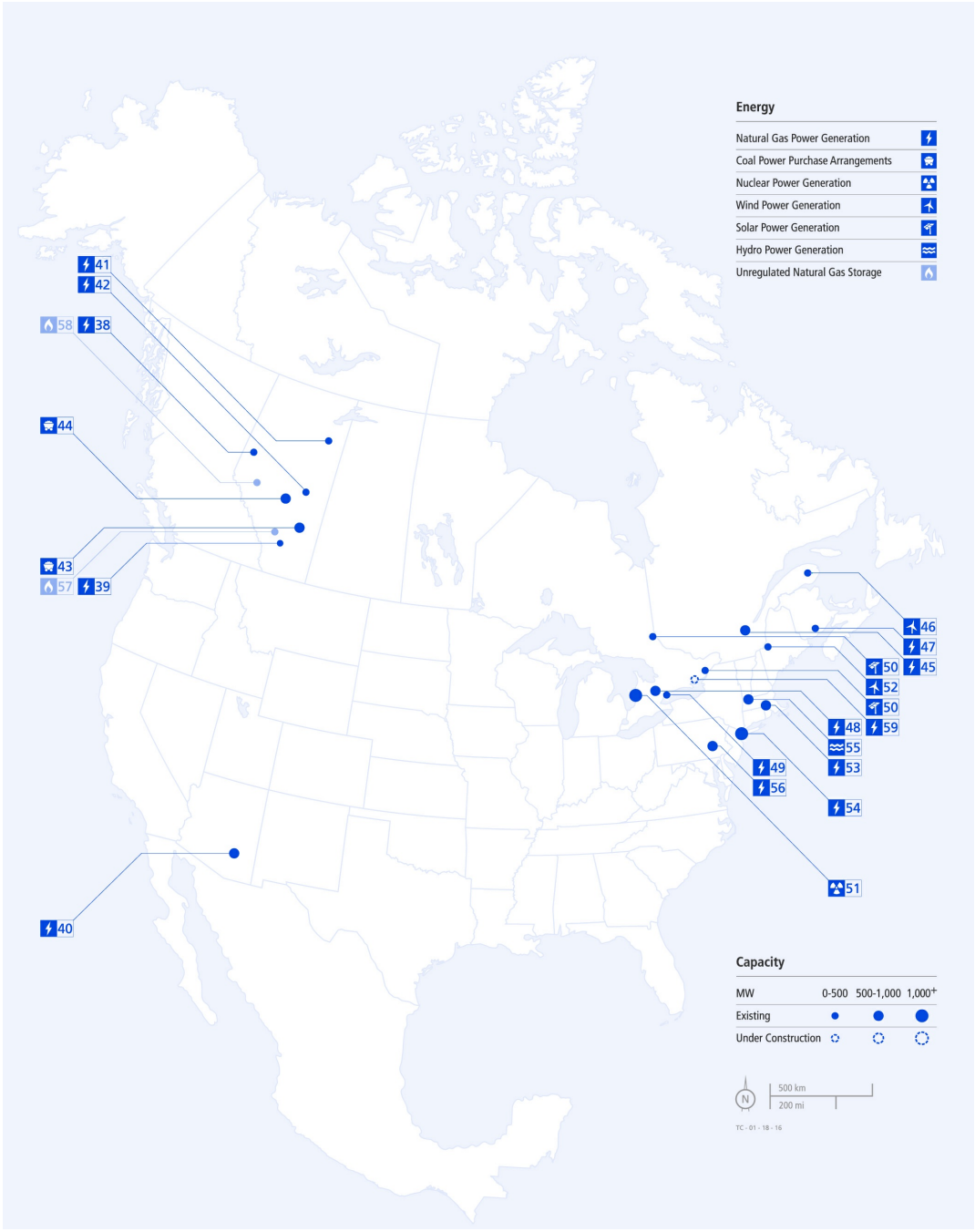
• Leverage our experience building, operating and investing in a diverse set of generation technologies, fuel types and commercial structures to replace aging infrastructure and participate in the shift from higher carbon emitting electricity sources to natural gas-fired, renewables and non-emitting resources

• Pursue organic growth and repowering opportunities at our existing sites to capture more value from our current investments

• Maximize the value of our existing unregulated Alberta natural gas storage assets. Natural gas storage's role in balancing and providing flexibility to the natural gas system is expected to grow as the market expands and becomes more dynamic as a result of the electric grid’s increased reliance on natural gas-fired capacity and from the addition of LNG export terminals

Highlights from 2015

- Organic growth at Bruce Power: executed agreement with the IESO to extend the operating life of the Bruce Power facility to 2064 and acquired an additional ownership interest in this facility, a primary source of emission-less generation for Ontario underpinned by a long-term contract
- Acquisition of Ironwood power plant: strategically located natural gas-fired investment in proximity to the Marcellus shale gas play with energy and capacity revenues in the PJM power market, North America’s largest and most liquid energy region. Facility is well positioned in a market that is transitioning away from coal-fired to natural gas generation and complements our existing wholesale marketing business
- Amendment to Bécancour contract: executed agreement with Hydro Québec allowing for dispatch of up to 570 MW of firm peak winter capacity for a term of 20 years beginning December 2016. Annual payments are incremental to existing capacity payments
- Began construction of the Napanee 900 MW natural gas-fired power plant

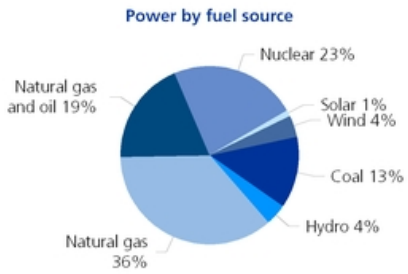

Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
41
42
58
38
44
43
57
39
40
46
47
50
45
52
50
48
59
55
53
49
56
54
51
Capacity
MW
0-500
500-1,000
1,000+
Existing
Under Construction
N
500 km
200 mi
TC - 01 - 18 - 16

We are the operator of all of our Energy assets, except for the Sheerness, Sundance A and Sundance B PPAs, Cartier Wind, Bruce and Portlands Energy.

		generating capacity (MW)	type of fuel	description	location	ownership
	Canadian Power 8,571 MW of power generation capacity (including facilities under construction)					
	Western Power 2,609 MW of power supply in Alberta and the western U.S.					
38	Bear Creek	80	natural gas	Cogeneration plant	Grande Prairie, Alberta	100%
39	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
40	Coolidge	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
41	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
42	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
43	Sheerness PPA	756	coal	Output contracted under PPA	Hanna, Alberta	100%
44	Sundance A PPA	560	coal	Output contracted under PPA	Wabamun, Alberta	100%
44	Sundance B PPA (Owned by ASTC Power Partnership[1])	353[2]	coal	Output contracted under PPA	Wabamun, Alberta	50%
	Eastern Power 2,939 MW of power generation capacity (including facilities under construction)					
45	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
46	Cartier Wind	365[2]	wind	Five wind power projects	Gaspésie, Québec	62%
47	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
48	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
49	Portlands Energy	275[2]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
50	Ontario Solar	76	solar	Eight solar facilities	Southern Ontario and New Liskeard, Ontario	100%
	Bruce Power 3,023 MW of power generation capacity					
51	Bruce Power	3,023[2]	nuclear	Eight operating reactors	Tiverton, Ontario	48.5%

		generating capacity (MW)	type of fuel	description	location	ownership
	U.S. Power 4,533 MW of power generation capacity					
52	Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
53	Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
54	Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
55	TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
56	Ironwood[3]	778	natural gas	Combined-cycle plant	Lebanon, Pennsylvania	100%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
57	CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
58	Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
	Under construction					
59	Napanee	900	natural gas	Combined-cycle plant	Greater Napanee, Ontario	100%

1 We have a 50 per cent interest in ASTC Power Partnership, which has a PPA for production from the Sundance B power generating facilities.
2 Our share of power generation capacity.
3 Acquired February 1, 2016.



RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Comparable depreciation and amortization is also a non-GAAP measure. See page 10 for more information on non-GAAP measures we use and page 108 for reconciliation to its GAAP equivalent.

year ended December 31 (millions of $)	2015	2014	2013
Comparable EBITDA	**1,280**	1,348	1,363
Comparable depreciation and amortization	**(336)**	(309)	(294)
Comparable EBIT	**944**	1,039	1,069
Specific items (pre-tax):			
Turbine equipment impairment charge	**(59)**	—	—
Bruce Power merger – debt retirement charge	**(36)**	—	—
Cancarb gain on sale	**—**	108	—
Niska contract termination	**—**	(43)	—
Risk management activities	**(37)**	(53)	44
Segmented earnings	**812**	1,051	1,113

Energy segmented earnings were $239 million lower in 2015 than in 2014 and $62 million lower in 2014 than in 2013 and included the following specific items that have been excluded from comparable EBIT:

- a $59 million pre-tax charge relating to an impairment in value on turbine equipment previously purchased for a new power development project that did not proceed. Various other projects have recently been evaluated for possible use of this equipment and those evaluations support the impairment of the carrying value. See Critical accounting estimates on page 101 for further information
- a $36 million pre-tax charge related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a gain in 2014 of $108 million on the sale of Cancarb Limited and its related power generation business, which closed in April 2014
- a net loss in 2014 of $43 million resulting from the contract termination payment to Niska Gas Storage 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 (millions of $, pre-tax)	2015	2014	2013
Canadian Power	**(8)**	(11)	(4)
U.S. Power	**(30)**	(55)	50
Natural Gas Storage	**1**	13	(2)
Total (losses)/gains from risk management activities	**(37)**	(53)	44

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

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

year ended December 31 (millions of $)	2015	2014	2013
Canadian Power			
Western Power	**72**	252	355
Eastern Power[1]	**394**	350	322
Bruce Power	**285**	314	310
Canadian Power – comparable EBITDA[2]	**751**	916	987
Comparable depreciation and amortization	**(190)**	(179)	(172)
Canadian Power – comparable EBIT[2]	**561**	737	815
U.S. Power (US$)			
U.S. Power – comparable EBITDA	**418**	376	323
Comparable depreciation and amortization	**(105)**	(107)	(107)
U.S. Power – comparable EBIT	**313**	269	216
Foreign exchange impact	**87**	27	7
U.S. Power – comparable EBIT (Cdn$)	**400**	296	223
Natural Gas Storage and other			
Natural Gas Storage and other – comparable EBITDA	**15**	44	63
Comparable depreciation and amortization	**(12)**	(12)	(12)
Natural Gas Storage and other – comparable EBIT	**3**	32	51
Business Development comparable EBITDA and EBIT	**(20)**	(26)	(20)
Energy – comparable EBIT[2]	**944**	1,039	1,069
Summary			
Energy – comparable EBITDA[2]	**1,280**	1,348	1,363
Comparable depreciation and amortization	**(336)**	(309)	(294)
Energy – comparable EBIT[2]	**944**	1,039	1,069

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.
2 Includes our share of equity income from our investments in ASTC Power Partnership and Portlands Energy, and our share of comparable income from equity investments from Bruce Power.

Comparable EBITDA for Energy was $68 million lower in 2015 than in 2014. The decrease was the net effect of:

- lower earnings from Western Power as a result of lower realized prices and lower PPA volumes
- higher earnings from U.S. Power due to increased margins and sales volumes to wholesale, commercial and industrial customers, partially offset by lower capacity revenue in New York and lower realized prices at our northeastern U.S. Power facilities
- higher earnings from Eastern Power primarily due to four solar facilities acquired in 2014
- lower earnings from Bruce Power due to higher operating expenses mostly offset by fewer unplanned outage days at Bruce A, as well as higher operating expenses and lower gains from contracting activities, partially offset by lower lease expense at Bruce B
- lower earnings from Natural Gas Storage due to lower realized natural gas storage price spreads
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

Comparable EBITDA for Energy was $15 million lower in 2014 compared to 2013. This decrease was the net effect of:

- lower earnings from Western Power due to lower realized prices
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices at our New York and New England facilities
- incremental earnings from Eastern Power primarily due to four solar facilities acquired in each of 2013 and 2014
- lower earnings from Natural Gas Storage due to lower realized natural gas storage price spreads.

OUTLOOK

Earnings

We expect 2016 earnings from the Energy segment to be similar to2015, assuming the net effect of the following expectations:

- acquisition of the Ironwood power plant in Pennsylvania
- increased ownership interest in Bruce Power
- increased planned maintenance activity at Bruce Power
- lower U.S. Power marketing contribution
- lower realized capacity prices in New York
- lower contributions from our power operations in Eastern Canada
- lower North American energy commodity prices
- higher GHG emissions costs in Alberta.

Although a significant portion of Energy's output is sold under long-term contracts, revenue from power that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by fluctuations in commodity prices and changes in seasonal natural gas storage price spreads will impact Natural Gas Storage earnings.

Weather, unplanned outages and unforeseen regulatory changes can play a role in spot markets and can drive fluctuations in our Energy results.

Western Power

Western Power earnings in 2016 are expected to be consistent with 2015. A well-supplied Alberta power market with slower demand growth and low natural gas prices is anticipated in 2016. Low average spot power prices are expected to continue in the near term, with average spot power prices in 2016 remaining similar to 2015 prices. Average spot market power prices in 2015 ($33/MWh) were materially lower than in 2014 ($50/MWh) primarily due to increased supply and low natural gas prices.

In 2015, the Alberta government renewed and initiated certain GHG policies that impact the electricity sector. GHG compliance costs associated with our PPAs are expected to increase in 2016. The Alberta government’s renewal and change to the SGER increases the emissions reduction target to 15% and increases the carbon levy to $20 per tonne in 2016, up from 12% and $15 per tonne in 2015. See the Significant events section for more information.

A new climate change policy was announced by the Alberta government in the fall of 2015 that positions the provincial economy to be less carbon intensive. According to this plan, Alberta will have an economy-wide carbon tax beginning in 2017, retire coal facilities by 2030 and add significant renewable electricity sources. The future Alberta electricity sector supply mix will feature significant levels of renewables and gas-fired capacity. We have expertise in building, operating and investing in a diverse set of generation technologies and are well positioned to participate in the Alberta electric supply transformation.

Eastern Power

All of our energy assets in eastern Canada are fully contracted. The Ontario assets are contracted with the IESO and are largely sheltered from spot market pricing. Eastern Power earnings in 2016 are expected to be slightly lower as a result of lower contractual earnings at Bécancour and reduced earnings from the sale of unused natural gas transportation. Beginning in December 2016, the Eastern Power earnings will be positively impacted from an agreement executed with Hydro Québec (HQ) to amend Bécancour’s electricity supply contract allowing HQ to dispatch up to 570 MW of firm peak winter capacity from the Bécancour facility.

Bruce Power

We expect 2016 equity income from Bruce Power to be consistent with 2015 results. The positive impact from the additional ownership interest acquired in Bruce Power effective December 3, 2015 is expected to be offset by increased planned maintenance activity in 2016.

During second quarter 2016, Bruce units 1 to 4 are expected to be removed from service for approximately one month to facilitate a station containment outage. This work program inspects and maintains key safety systems including containment structures, and is required to be completed approximately once every decade. Additional planned maintenance is scheduled for first and fourth quarters of 2016. The overall average plant availability percentages in 2016 are expected to be in the low 80s.

Bruce Power's new agreement with the IESO to extend the operating life of the Bruce Power facility to 2064 along with our acquisition of an additional ownership interest in the facility is expected to provide long-term growth in earnings. See Significant events for more information.

U.S. Power

U.S. Power results are expected to be higher in 2016 compared to 2015 due to our acquisition of the Ironwood power plant in Lebanon, Pennsylvania on February 1, 2016, partially offset by lower marketing margins and lower commodity prices.

U.S. northeast power markets are currently well supplied and we expect prices to remain at lower levels in 2016 along with more normalized levels of volatility.

In recent years, gas pipeline constraints in New England resulted in significant winter price volatility contributing to increased seasonal margins earned by our power marketing business in 2015. The market's response to this increased volatility and the implementation of winter reliability programs has mitigated the impact of constrained gas supply reducing power price volatility. This reduced price volatility also contributes to lower expected earnings in 2016.

Our northeastern U.S. power facilities, particularly Ravenswood in New York, also earn significant revenues through participation in regional capacity markets. New York Spot capacity prices are on average expected to be lower in 2016 than 2015 primarily due to a reduction to the locational requirement used in the capacity pricing structure.

Natural Gas Storage

A modest recovery of seasonal spreads is expected to occur in 2016. Additionally, the resolution of Alberta natural gas pipeline outages that occurred in 2015 is expected to have a positive impact on revenue in 2016. As a result, the 2016 segment contribution is expected to be slightly higher compared to 2015 results.

Capital spending

We spent a total of $0.4 billion in 2015 and expect to spend approximately $0.6 billion on capital projects in Energy in 2016.

Equity investments and acquisitions

In 2015, we acquired an additional 14.89 per cent ownership interest in Bruce B for $236 million and invested $0.2 billion in Bruce Power for capital projects. We expect to invest approximately $0.3 billion in Bruce Power in 2016.

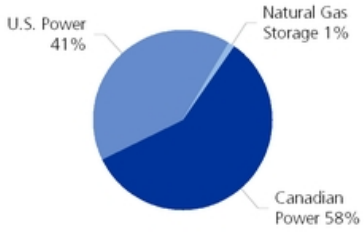
Our acquisition of the Ironwood power plant in Lebanon, Pennsylvania closed on February 1, 2016 for US$657 million before post closing adjustments.

UNDERSTANDING THE ENERGY BUSINESS

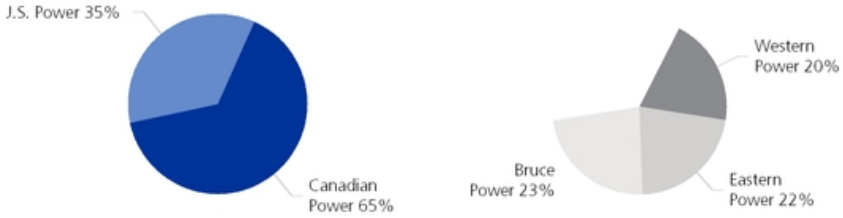
Our Energy business is made up of three groups:

- Canadian Power
- U.S. Power
- Natural Gas Storage

Energy comparable EBIT – contribution by group, excluding business development expenses
year ended December 31, 2015



Power generation capacity – contribution by group
year ended December 31, 2015 (includes facilities in development/acquired)



Canadian Power

Western Power

We own or have the rights to approximately 2,600 MW of power supply in Alberta and Arizona through three long-term PPAs, four natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

	Type of contract	With	Expires
Sheerness PPA	Power purchased under a 20-year PPA	ATCO Power and TransAlta Utilities Corporation	2020
Sundance A PPA	Power purchased under a 20-year PPA	TransAlta Utilities Corporation	2017
Sundance B PPA	Power purchased under a 20-year PPA (own 50 per cent through the ASTC Power Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

	Type of contract	With	Expires
Coolidge	Power sold under a 20-year PPA	Salt River Project Agricultural Improvements & Power District	2031

Earnings in our Western Power business are maximized by maintaining and optimizing the operations of our power plants, and through various marketing activities.

A disciplined operational strategy is critical to maximizing output and revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability, and is not a function of market price.

The marketing function is critical for optimizing returns and managing risk through direct sales to medium and large industrial and commercial companies and other market participants. Our marketing group sells power sourced through the PPAs, markets uncommitted volumes from the cogeneration plants, and buys and sells power and natural gas to maximize earnings from our assets. To reduce exposure associated with uncontracted volumes, we sell a portion of our power in forward sales markets when acceptable contract terms are available.

A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium to large industrial and commercial companies as well as other market participants and will affect our average realized price (versus spot price) in future periods.

Eastern Power

We own or are developing approximately 3,000 MW of power generation capacity in eastern Canada. All of the power produced by these assets is sold under long-term contracts.

Disciplined maintenance of plant operations is critical to the results of our Eastern Power assets, where earnings are based on plant availability and performance.

Assets currently operating under long-term contracts are as follows:

	Type of contract	With	Expires
Bécancour[1,2]	20-year PPA and tolling agreement Steam sold to an industrial customer	Hydro-Québec	2036
Cartier Wind	20-year PPA	Hydro-Québec	2026–2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2024
Halton Hills	20-year Clean Energy Supply contract	IESO	2030
Portlands Energy	20-year Clean Energy Supply contract	IESO	2029
Ontario Solar[3]	20-year Feed-in Tariff (FIT) contracts	IESO	2032–2034

1 Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.

2 In August 2015, we executed an agreement with HQ to amend Bécancour's electricity supply contract. The amendment allows HQ to dispatch up to 570 MW of firm peak winter capacity from the Bécancour facility for a term of 20 years commencing in December 2016. Annual tolling payments received for this new service will be incremental to existing capacity payments earned under the agreement and will expire in 2036. The existing capacity payments terminate in 2026.

3 We acquired four facilities in 2013 and an additional four facilities in 2014.

Assets currently under construction are as follows:

	Type of contract	With	Expires
Napanee[1]	20-year Clean Energy Supply contract	IESO	20 years from in-service date

1 Expected in-service date is between late 2017 and early 2018

Western and Eastern Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 10 for more information.

year ended December 31 (millions of $)	2015	2014	2013
Revenue[1]			
Western Power	**534**	736	605
Eastern Power[2]	**455**	428	400
Other[3]	**62**	85	108
	1,051	1,249	1,113
Income from equity investments[4]	**8**	45	141
Commodity purchases resold	**(353)**	(404)	(283)
Plant operating costs and other	**(248)**	(299)	(298)
Exclude risk management activities[1]	**8**	11	4
Comparable EBITDA	**466**	602	677
Comparable depreciation and amortization	**(190)**	(179)	(172)
Comparable EBIT	**276**	423	505
Breakdown of comparable EBITDA			
Western Power	**72**	252	355
Eastern Power	**394**	350	322
Comparable EBITDA	**466**	602	677

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

2 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.

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

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

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

year ended December 31	2015	2014	2013
Sales volumes (GWh)			
Supply			
Generation			
Western Power	**2,519**	2,517	2,728
Eastern Power[1]	**3,911**	3,080	3,822
Purchased			
Sundance A & B and Sheerness PPAs and other[2]	**10,617**	11,472	8,223
Other purchases	**154**	16	13
	17,201	17,085	14,786
Sales			
Contracted			
Western Power	**7,707**	10,484	7,864
Eastern Power[1]	**3,911**	3,080	3,822
Spot			
Western Power	**5,583**	3,521	3,100
	17,201	17,085	14,786
Plant availability[3]			
Western Power[4]	**97%**	96%	95%
Eastern Power[1,5]	**97%**	91%	90%

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, and one solar facility acquired in December 2014.
2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in September 2013 and Unit 2 returned to service in October 2013 after extended outages.
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 us under PPAs.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA in 2015 was $180 million lower than in 2014. The decrease was due to lower realized power prices and lower PPA volumes.

Average spot market power prices in Alberta decreased by 34 per cent from approximately $50/MWh in 2014 to approximately $33/MWh in 2015. The addition of new natural gas-fired and wind plants over the last year-and-a-half have contributed to a well supplied market and very few higher priced hours were observed. While we manage spot market power price volatility through the use of forward contracts, this significant decrease in spot market prices also reduced our realized power prices in 2015 compared to 2014.

The decrease in equity earnings of $37 million in 2015 compared to 2014 was primarily due to the impact of lower Alberta spot market prices on earnings from the ASTC Power Partnership which holds our 50 per cent ownership interest in the Sundance B PPA. Equity earnings does not include the impact of related contracting activities.

In 2014, Western Power's comparable EBITDA was $103 million lower than 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 38 per cent from approximately $80/MWh in 2013 to approximately $50/MWh in 2014.

Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities. Approximately 58 per cent of Western Power sales volumes were sold under contract in 2015 compared to 75 per cent in 2014 and 72 per cent in 2013.

Eastern Power

Eastern Power's comparable EBITDA in 2015 was $44 million higher than 2014 due to the net effect of incremental earnings from solar facilities acquired in 2014, higher contractual earnings at Bécancour and lower earnings on the sale of unused natural gas transportation.

In 2014, Eastern Power's comparable EBITDA was $28 million higher than 2013 due to the net effect of incremental earnings from the four solar facilities acquired in 2013, the additional four facilities acquired in late 2014 and higher contractual earnings at Bécancour.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,300 MW. Bruce Power leases the eight nuclear facilities from Ontario Power Generation (OPG).

Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned outages.

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

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

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

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

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

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

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

Bruce A fixed price	Per MWh
April 1, 2015 – December 31, 2015	$73.42
April 1, 2014 – March 31, 2015	$71.70
April 1, 2013 – March 31, 2014	$70.99

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

Bruce B floor price	Per MWh
April 1, 2015 – December 31, 2015	$54.13
April 1, 2014 – March 31, 2015	$52.86
April 1, 2013 – March 31, 2014	$52.34

Amounts received under the Bruce B Units 5 to 8 floor price mechanism within a calendar year were subject to repayment if the average spot price in a month exceeded the floor price. The average spot power price in each month of 2015 was less than the floor price and therefore no amounts received under the floor price mechanism in 2015 are subject to repayment. Amounts received above the floor price in first quarter 2014 were repaid to the IESO in January 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 contract also provides for payment if the IESO reduces Bruce Power's generation to balance the supply of and demand for electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered "deemed generation", for which Bruce Power is paid the contract price.

Bruce Power results

Results reflect our proportionate share. Beginning in 2016, results from Bruce Power will be reported on a combined basis to reflect the merged entity. Comparable income from equity investments is a non-GAAP measure. See page 10 for more information on non-GAAP measures we use.

year ended December 31 (millions of $, unless noted otherwise)	2015	2014	2013
Comparable income from equity investments[1]			
Bruce A	**205**	209	202
Bruce B	**80**	105	108
	285	314	310
Comprised of:			
Revenues	**1,301**	1,256	1,258
Operating expenses	**(691)**	(623)	(618)
Depreciation and other	**(325)**	(319)	(330)
Comparable income from equity investments[1]	**285**	314	310
Bruce Power merger – debt retirement charge	**(36)**	—	—
Income from equity investments[1]	**249**	314	310
Bruce Power – other information			
Plant availability[2]			
Bruce A	**87%**	82%	82%
Bruce B	**87%**	90%	89%
Combined Bruce Power	**87%**	86%	86%
Planned outage days			
Bruce A	**164**	118	123
Bruce B	**163**	127	140
Unplanned outage days			
Bruce A	**28**	123	63
Bruce B	**17**	4	20
Sales volumes (GWh)[1]			
Bruce A	**11,148**	10,526	10,458
Bruce B	**8,210**	8,197	8,010
	19,358	18,723	18,468
Realized sales price per MWh[3]			
Bruce A	**$71**	$72	$70
Bruce B	**$55**	$56	$54
Combined Bruce Power	**$63**	$63	$62

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B up to December 3, 2015 when we increased our ownership percentage in Bruce B, and Bruce A and B were merged. Sales volumes include deemed generation.

2 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.

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

Comparable income from equity investments from Bruce A in 2015 was $4 million lower than 2014. The decrease was mainly due to higher operating expenses, partially offset by higher volumes resulting from fewer unplanned outage days.

Comparable income from equity investments from Bruce B in 2015 was $25 million lower than 2014. The decrease was mainly due to higher operating expenses and lower gains from contracting activities, partially offset by lower lease expense based on the terms of the lease agreement with OPG. All Bruce B units were removed from service in April 2015 to allow for inspection of the Bruce B vacuum building as mandated by the Canadian Nuclear Safety Commission to occur approximately once every decade. The outage, along with additional planned maintenance on Unit 6, was completed successfully during second quarter 2015.

Comparable income from equity investments from Bruce A in 2014 was $7 million higher than 2013. The increase was mainly due to lower depreciation and operating expenses and higher volumes, partially offset by recognition of an insurance recovery of approximately $40 million in the first quarter 2013. The negative impact of increased outage days in 2014 was offset by higher generation levels while operating.

Comparable income from equity investments from Bruce B in 2014 was $3 million lower than 2013. The decrease was mainly due to higher lease expense recognized based on the terms of the lease agreement with OPG, partially offset by higher volumes and lower operating costs resulting from lower outage days.

U.S. Power

We own approximately 4,500 MW of power generation capacity in New York, New England and Pennsylvania, including plants powered by natural gas, oil, hydro and wind. We have recently acquired the 778 MW Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, which delivers energy into the PJM power market.

We earn revenues in New York, PJM and New England by providing generation capacity and by selling energy. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. The energy markets compensate power providers for the actual energy they supply.

Providing capacity

Capacity revenue in New York, PJM and New England are a function of two factors, capacity prices and plant availability. It is important for us to keep our plant availability high to maximize the amount of capacity for which we get paid.

The price required for capacity in all of the three U.S. Northeast capacity markets where we have assets is determined by annual competitive auctions. Auction results are impacted by actual power supply and projected power demand levels within demand curve price setting processes. Each U.S. Northeast capacity market is similar in design, however, each has unique features. For example, the price paid for capacity in both the PJM and New England Power Pools is determined by annual competitive auctions that are held three years in advance of the applicable capacity year, while the New York capacity market does not have a three year advance attribute.

Selling energy

We focus on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the following power markets:

- New York, operated by the New York ISO
- New England, operated by the New England ISO
- PJM Interconnection area (PJM).

We also earn additional revenues by bundling power sales with other energy services.

We meet our power sales commitments using power we generate ourselves or acquire at fixed prices, thereby reducing our exposure to changes in commodity prices.

The timing of recognizing earnings from our U.S. power marketing business is impacted by different pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased to fulfill our sales obligations over the term of the contracts. The costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers includes the impact of certain contracts to purchase power over multiple periods at a flat price. Because the price we charge our customers is typically shaped to the market, the impact of these two contract pricing profiles has generally resulted in higher earnings in December to February, offset by lower earnings between March and November, with overall positive margins over the term of the contracts.

U.S. Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 10 for more information.

year ended December 31 (millions of US$)	2015	2014	2013
Revenue			
Power[1]	**1,975**	1,794	1,587
Capacity	**317**	362	295
	2,292	2,156	1,882
Commodity purchases resold	**(1,474)**	(1,297)	(1,003)
Plant operating costs and other[2]	**(422)**	(529)	(509)
Exclude risk management activities[1]	**22**	46	(47)
Comparable EBITDA	**418**	376	323
Comparable depreciation and amortization	**(105)**	(107)	(107)
Comparable EBIT	**313**	269	216

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

Sales volumes and plant availability

year ended December 31	2015	2014	2013
Physical sales volumes (GWh)			
Supply			
Generation	**7,849**	7,742	6,173
Purchased	**20,937**	13,798	12,050
	28,786	21,540	18,223
Plant availability[1, 2]	**78%**	82%	84%

1 The percentage of time the plant was available to generate power, regardless of whether it is running.
2 Plant availability was lower in 2015 due to an unplanned outage at the Ravenswood facility. The unit returned to service in May 2015.

U.S. Power - other information

year ended December 31	2015	2014	2013
Average Spot Power Prices (US$ per MWh)			
New England[1]	**42**	65	57
New York[2]	**39**	61	53
Average New York[2] Zone J Spot Capacity Prices (US$ per KW-M)	**11.44**	13.96	11.31

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

U.S. Power's comparable EBITDA in 2015 was US$42 million higher than 2014. This reflected the net effect of:

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

In 2014, U.S. Power's comparable EBITDA was US$53 million higher than 2013. This reflected the net effect of:

- higher realized capacity prices primarily in New York
- higher realized power prices for the New England and New York facilities
- higher generation volumes primarily at the Ravenswood facility

- higher prices and related costs on increased volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers.

Higher margins and higher sales volumes to wholesale, commercial and industrial customers in both PJM and New England markets resulted in significantly higher earnings during 2015 compared to 2014. The expansion of our customer base in these markets combined with lower and less volatile prices on volumes purchased to fulfill our sale obligations in 2015, provided the opportunity for higher earnings.

Wholesale electricity prices in New York and New England were lower in 2015 compared to 2014. Reductions in fuel oil prices and increased availability of liquefied natural gas in winter 2015 helped to mitigate the impact of pipeline constraints and keep peak price excursions limited compared to winter 2014. Average spot power prices in 2015 in New England decreased approximately 35 per cent and in New York spot power prices decreased approximately 36 per cent compared to 2014.

Average New York Zone J spot capacity prices were approximately 18 per cent lower in 2015 than in 2014. The decrease in spot prices and the impact of hedging activities, resulted in lower realized capacity prices in New York in 2015. The lower spot capacity prices were primarily due to increased available operational supply in New York City's Zone J market.

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

Physical sales volumes and purchased volumes sold to wholesale, commercial and industrial customers were higher in 2015 compared to 2014 as we have expanded our customer base in both PJM and New England markets.

As at December 31, 2015, approximately 6,600 GWh or 70 per cent of U.S. Power's planned generation is contracted for 2016, and 3,000 GWh or 33 per cent for 2017. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage

We own and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. This business operates independently from our regulated natural gas transmission business and from ANR's regulated storage business, which are included in our Natural Gas Pipelines segment.

Storage capacity

year ended December 31, 2015	Working gas storage capacity (Bcf)	Maximum injection/ withdrawal capacity (MMcf/d)
Edson	50	725
CrossAlta	68	550
	118	1,275

We also hold a contract for additional Alberta-based storage capacity with a third party.

Our natural gas storage business helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give customers the ability to capture value from short-term price movements. The natural gas storage business is affected by the change in seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

Our gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide gas storage services on a short, medium, and/or long term basis.

We also enter into proprietary natural gas storage transactions, which include a forward purchase of our own natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter

withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to changes in gas prices.

Natural Gas Storage and other results

Comparable EBITDA in 2015 was $29 million lower than 2014, mainly due to decreased proprietary and third party storage revenue as a result of lower realized natural gas storage price spreads as well as extreme natural gas price volatility experienced in first quarter 2014.

In 2014, comparable EBITDA was $19 million lower than 2013, mainly due to decreased third party storage revenue as a result of lower realized natural gas storage price spreads.

SIGNIFICANT EVENTS

Canadian Power

Alberta Greenhouse Gas Emissions

In 2015, the Alberta government announced a renewal and change to the SGER in Alberta. Since 2007, under the SGER, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions by 12 per cent below an average intensity baseline and a carbon levy of $15 per tonne is placed on emissions above this target.

The changed regulations include an increase in the emissions reductions target to 15 per cent in 2016 and 20 per cent in 2017, along with an increase in the carbon levy to $20 per tonne in 2016 and $30 per tonne in 2017. Starting in 2018, coal-fired generators will pay $30 per tonne of CO_2 on emissions above what Alberta's cleanest natural gas-fired plant would emit to produce an equivalent amount of electricity. While our Sundance and Sheerness PPAs are subject to this regulation, our inventory of carbon offset credits will mitigate some of these increased costs. The remaining compliance costs are expected to be somewhat recovered through increased market pricing but the full extent is not known at this time.

Napanee

In January 2015, we began construction activities on a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late-2017 or early-2018. Production from the facility is fully contracted with the IESO.

Bécancour

In August 2015, we executed an agreement with HQ to amend Bécancour's electricity supply contract. The amendment allows HQ to dispatch up to 570 MW of firm peak winter capacity from the Bécancour facility for a term of 20 years commencing in December 2016. Annual payments received for this new service will be incremental to existing capacity payments earned under the agreement. In October 2015, the Régie de l'énergie approved the amended contract.

Bruce Power

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

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

In connection with this opportunity, we exercised our option to acquire an additional 14.89 per cent ownership interest in Bruce B for $236 million from OMERS. Subsequent to this acquisition, Bruce A and Bruce B were merged to form a single partnership structure. In 2015, we recognized a $36 million charge, representing our proportionate share, on the retirement of Bruce Power debt in conjunction with this merger. Each partner now holds a 48.5 per cent interest in this newly merged partnership structure.

U.S. Power

Ravenswood

In late May 2015, the 972 MW Unit 30 at the Ravenswood Generating Station returned to service after a September 2014 unplanned outage which resulted from a problem with the generator associated with the high pressure turbine. Insurance recoveries for this event are expected to be received in 2016. 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 although the recording of earnings will not coincide with lost revenues due to timing of the insurance proceeds.

Ironwood

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

BUSINESS RISKS

The following are risks specific to our Energy business. See page 94 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Fluctuating power and natural gas market prices

Power and natural gas prices are affected by fluctuations in supply and demand, weather, and by general economic conditions. The power generation facilities in our Western Power operations in Alberta, and in our U.S. Northeast Power operations are exposed to commodity price volatility.

Earnings from these businesses are generally correlated to the prevailing power supply and demand conditions. In the U.S. Northeast, the price of natural gas also has a significant impact on power prices, as energy prices in these markets are usually set by gas-fired power supplies. Extended periods of low gas prices will generally exert downward pressure on power prices and therefore on earnings from our U.S. Northeast facilities.

Our portfolio of assets in eastern Canada and our Coolidge Generating Station in Arizona are fully contracted, and are therefore not materially impacted by fluctuating commodity prices. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms.

To mitigate the impact of power price volatility in Alberta and the U.S. Northeast, we sell a portion of our supply under medium to long-term sales contracts where contract terms are acceptable. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements to ensure we have adequate power supply to fulfill sales obligations if unexpected plant outages occur. This unsold supply is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

Alberta Power Purchase Arrangements

As the Alberta power market conforms to the new climate change policies announced in 2015, the full extent of the impact to the economics of the PPAs is not known at this time. However, change of law provisions exist in the arrangements that afford PPA buyers an option to turn back PPAs to the Alberta Balancing Pool in the event that holding a PPA is deemed to be no longer economic.

U.S. Power capacity payments

A significant portion of revenues earned by our U.S. Northeast operations come from capacity payments where prices are determined in various competitive auctions. Fluctuations in capacity prices can have a material impact on these businesses. Auction pricing results are impacted by the prevailing supply and demand conditions for capacity and other factors. All three U.S. Northeast capacity markets where we have assets feature demand curve price setting processes driven by a number of established parameters and other rules that are subject to periodic review and revisions by the respective ISOs and FERC.

Plant availability

Optimizing and maintaining plant availability is essential to the continued success of our Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue, and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations.

We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive, risk-based preventive maintenance programs and making effective capital investments.

For facilities we do not operate, our purchase agreements include a financial remedy if a plant owner does not deliver as agreed. The Sundance and Sheerness PPAs, for example, require the producers to pay us market-based penalties if they cannot supply the amount of power we have agreed to purchase.

Execution and capital costs

We make substantial capital commitments developing power generation infrastructure based on the assumption that these assets will deliver an attractive return on investment. While we carefully consider the scope and expected costs of our capital projects, we are exposed to execution and capital cost overrun risk which may impact our return on these projects. We mitigate this risk by implementing comprehensive project governance and oversight processes and through the structuring of commercial arrangements where certain execution and capital cost risks may be shared with counterparties.

Regulatory

We operate in both regulated and deregulated power markets in both the United States and Canada. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, emissions costs, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power or capacity, or both. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Weather

Significant changes in temperature and other weather events have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply. Seasonal changes in temperature can reduce the efficiency of our natural gas-fired power plants, and the amount of power they produce. Variable wind speeds affect earnings from our wind assets, and sun-light hours and intensity affects earnings from our solar assets.

Hydrology

Our hydroelectric power generation facilities in the U.S. Northeast are subject to hydrology risks that can impact the volume of water available for generation at these facilities including weather changes and events, local river management and potential dam failures at these plants or upstream facilities.

Competition

We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants in deregulated markets will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies, additional supply from regional power transmission interconnections and new supply in the form of distributed generation. We also face competition from other power companies in the greenfield power plant development arena.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). Comparable depreciation and amortization is also a non-GAAP measure. See page 10 for more information on non-GAAP measures we use and page 108 for reconciliation to its GAAP equivalent.

year ended December 31 (millions of $)	2015	2014	2013
Comparable EBITDA	**(171)**	(127)	(108)
Comparable depreciation and amortization	**(31)**	(23)	(16)
Comparable EBIT	**(202)**	(150)	(124)
Specific item:			
Restructuring costs	**(99)**	—	—
Segmented losses	**(301)**	(150)	(124)

Corporate segmented losses in 2015 increased by $151 million compared to 2014 and included a charge of $99 million before tax for restructuring charges comprised of $56 million mainly related to 2015 severance costs and a provision of $43 million for 2016 planned severance costs and expected future losses under lease commitments. See below for more information on our corporate restructuring and business transformation. This amount has been excluded from our calculation of comparable EBIT.

Corporate restructuring and business transformation

In mid-2015, we commenced a business restructuring and transformation initiative. While there is no change to our corporate strategy, we have undertaken this initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations.

At December 31, 2015, we had incurred $122 million before tax of 2015 corporate restructuring charges primarily related to severance, and recorded a provision of $87 million before tax related to planned severance costs in 2016 and expected future losses under lease commitments.

Of the total corporate restructuring charges of $209 million, $157 million was recorded in plant operating costs and other in the consolidated statement of income which was partially offset by $58 million recorded in revenues in the consolidated statement of income related to costs that were recoverable through current year regulatory and tolling structures. In addition, $44 million was recorded as a regulatory asset on the consolidated balance sheet, as it is expected to be recovered in future periods' regulatory and tolling structures, and $8 million was capitalized to projects impacted by the corporate restructuring.

We continue to progress our restructuring and business transformation initiative with further work to be completed in 2016. Benefits, in the form of enhanced business efficiencies and effectiveness, will be reflected in savings related to the execution of our capital programs, flow-through amounts to customers under established regulatory and commercial arrangements, and increased earnings. Determination of the amount and allocation of these benefits is predicated on completing additional phases of the initiative either underway or in the planning stage.

OTHER INCOME STATEMENT ITEMS

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures. See page 10 for more information on non-GAAP measures we use and page 108 for reconciliation to its GAAP equivalent.

Interest Expense

year ended December 31 (millions of $)	2015	2014	2013
Comparable interest on long-term debt (including interest on junior subordinated notes)			
Canadian dollar-denominated	**(437)**	(443)	(495)
U.S. dollar-denominated	**(911)**	(854)	(766)
Foreign exchange	**(255)**	(90)	(20)
	(1,603)	(1,387)	(1,281)
Other interest and amortization expense	**(47)**	(70)	10
Capitalized interest	**280**	259	287
Comparable interest expense	**(1,370)**	(1,198)	(984)
Specific item:			
NEB 2013 Decision – 2012	—	—	(1)
Interest expense	**(1,370)**	(1,198)	(985)

Comparable interest expense in 2015 was $172 million higher than in 2014 due to the net effect of:

- higher interest expense as a result of long term debt issuances partially offset by Canadian and U.S. dollar-denominated debt maturities. See the Financial condition section on page 82 for details on long term debt
- a stronger U.S dollar and its effect on the foreign exchange impact on interest expense related to U.S. dollar-denominated debt
- lower carrying charges to shippers in 2015 on the net revenue variance for the Canadian Mainline
- higher capitalized interest primarily due to capital spending on Liquids Pipelines projects, LNG projects and the Napanee power generating facility, partially offset by lower capitalized interest on the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014.

Comparable interest expense in 2014 was $214 million higher than 2013 due to the net effect of:

- higher interest expense as a result of long term debt issuances partially offset by Canadian and U.S. dollar-denominated debt maturities
- a stronger U.S dollar and its effect on the foreign exchange impact on interest expense related to U.S. dollar-denominated debt
- higher carrying charges to shippers in 2014 on the net revenue variance for Canadian Mainline
- lower capitalized interest due to the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014, partially offset by higher capitalized interest primarily for Keystone XL.

Interest income and other

year ended December 31 (millions of $)	2015	2014	2013
Comparable interest income and other	**184**	112	42
Specific items (pre-tax):			
NEB 2013 Decision – 2012	**—**	—	1
Risk management activities	**(21)**	(21)	(9)
Interest income and other	**163**	91	34

In 2015 comparable interest income and other was $72 millionhigher than 2014. In 2014, comparable interest income and other was$70 million higher than 2013. These variances were the net result of:

- increased AFUDC related to our rate-regulated projects, including Energy East Pipeline and our Mexico pipeline projects
- higher realized losses in 2015 compared to 2014 and 2014 compared to 2013 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

Income tax expense

year ended December 31 (millions of $)	2015	2014	2013
Comparable income tax expense	**(903)**	(859)	(662)
Specific items:			
Keystone XL impairment charge	**795**	—	—
TC Offshore loss on sale	**39**	—	—
Restructuring costs	**25**	—	—
Turbine equipment impairment charge	**16**	—	—
Bruce Power merger – debt retirement charge	**9**	—	—
Alberta corporate income tax rate increase	**(34)**	—	—
Cancarb gain on sale	**—**	(9)	—
Niska contract termination	**—**	11	—
Gas Pacifico/INNERGY gain on sale	**—**	(1)	—
NEB 2013 Decision – 2012	**—**	—	42
Part VI.I income tax adjustment	**—**	—	25
Risk management activities	**19**	27	(16)
Income tax expense	**(34)**	(831)	(611)

Comparable income tax expense increased $44 million in 2015 compared to 2014 mainly because of higher pre-tax earnings in 2015 compared to 2014 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

Comparable income tax expense increased $197 million in 2014 compared to 2013 because of higher pre-tax earnings in 2014, 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.

Net income attributable to non-controlling interests

Comparable net income attributable to non-controlling interests is a non-GAAP measure. See page 10 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2015	2014	2013
Comparable net income attributable to non-controlling interests	**(205)**	(153)	(125)
Specific item:			
TC PipeLines, LP – Great Lakes impairment	**199**	—	—
Net income attributable to non-controlling interests	**(6)**	(153)	(125)

Net income attributable to non-controlling interests decreased by $147 million in 2015 compared to 2014 due to an impairment charge recorded by TC PipeLines, LP related to their equity investment goodwill in Great Lakes. At December 31, 2015, TC PipeLines, LP recorded an impairment of US$199 million. On consolidation, we recorded the non-controlling interests' 72 per cent of this TC PipeLines, LP impairment charge, which was US$143 million, or $199 million (in Canadian dollars). TC PipeLines, LP's impairment charge is not recognized at the TransCanada consolidation level as a result of our lower carrying value of Great Lakes. This $199 million positive impact to net income attributable to non-controlling interests is excluded from comparable net income attributable to non-controlling interests. See Critical accounting estimates section on page 101 for more information on our goodwill impairment testing.

Comparable net income attributable to non-controlling interests increased by $52 million in 2015 compared to 2014 due to higher earnings resulting from the sale of our remaining 30 per cent direct interests in GTN in April 2015 and Bison in October 2014 to TC PipeLines, LP along with the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP.

Comparable net income attributable to non-controlling interest increased $28 million in 2014 compared to 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 and the remaining 30 per cent of Bison in October 2014. This was partially offset by the redemption of TCPL Series U preferred shares in October 2013 and TCPL Series Y preferred shares in March 2014.

Preferred share dividends

year ended December 31 (millions of $)	2015	2014	2013
Preferred share dividends	**(94)**	(97)	(74)

Preferred share dividends were $94 million for 2015. See Financial condition section on page 82 for more information. Preferred share dividends increased $23 million to $97 million in 2014 compared to $74 million in 2013 due to the issuance of Series 7 preferred shares in March 2013.

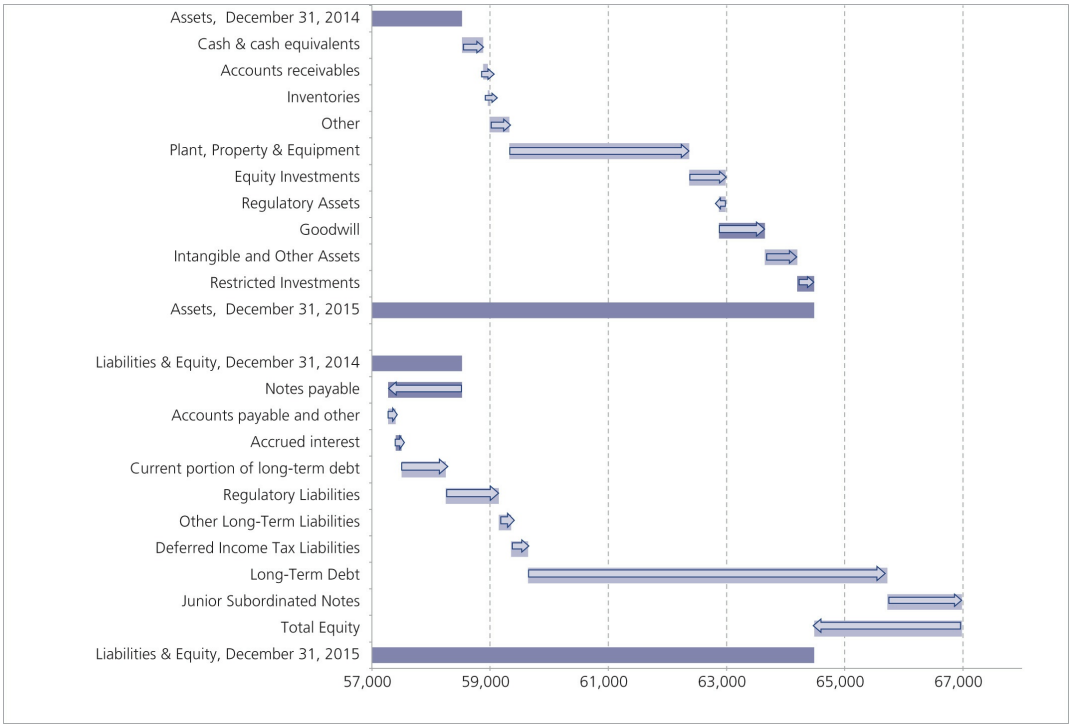
Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

We believe we have the financial capacity to fund our existing capital program through our predictable cash flow from our operations, access to capital markets, portfolio management including proceeds from the sale of natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

Balance sheet analysis

As of December 31, 2015, assets increased by $6.0 billion, liabilities increased by $8.5 billion and equity decreased by $2.5 billion compared to December 31, 2014.



The effect of the strengthened U.S. dollar in 2015 resulted in increases to the Canadian dollar equivalent of our U.S. dollar assets, liabilities and non-controlling interests. Also impacting the increase to assets were:

- investments in property, plant and equipment on the NGTL System, Mexico pipeline construction, ANR, Northern Courier and Napanee
- equity investments in Bruce Power and Grand Rapids
- capital investment in projects under development including Energy East.

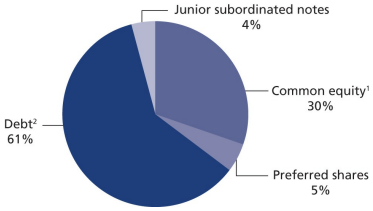
These increases to assets were partially offset by the impairment of Keystone XL and related projects.

Aside from the foreign exchange impact, the increase in liabilities was mainly due to the issuance in 2015 of long-term debt and junior subordinated debt exceeding repayment and increased regulatory liabilities for the Canadian Mainline.

The decrease in equity in 2015 was mainly due to the net loss attributable to controlling interests of $1,146 million and the dividends declared on common and preferred shares in the year.

Consolidated capital structure

at December 31, 2015



1 Includes non-controlling interests in TC PipeLines, LP and Portland
2 Net of cash and excluding junior subordinated notes

As at December 31, 2015, we had unused capacity of $2.0 billion, $2.0 billion and US$4.0 billion under our equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to the North American debt and equity markets.

We were in compliance with all of our financial covenants at December 31, 2015. Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios.

Cash flow

The following tables summarize the consolidated cash flow of our business.

year ended December 31 (millions of $)	2015	2014	2013
Net cash provided by operations	**4,115**	4,079	3,674
Net cash used in investing activities	**(4,610)**	(4,144)	(5,120)
Deficiency	**(495)**	(65)	(1,446)
Net cash provided by/(used in) financing activities	**744**	(373)	1,794
	249	(438)	348
Effect of foreign exchange rate changes on Cash and Cash Equivalents	**112**	—	28
Net change in Cash and Cash Equivalents	**361**	(438)	376

We continue to fund our capital program through cash flow from operations, capital market financing activities and the sale of our U.S. natural gas pipeline assets to TC PipeLines, LP.

Liquidity will continue to be comprised of predictable cash flow generated from operations, committed credit facilities, our ability to access debt and equity markets in both Canada and the U.S., portfolio management including additional drop downs of our U.S. natural gas pipeline assets into TC PipeLines, LP and cash on hand.

The drop down of our remaining U.S. natural gas pipeline assets into TC PipeLines, LP remains an important financing lever for us as it executes our capital growth program, subject to actual funding needs, market conditions, the relative attractiveness of alternate capital sources and the approvals of TC PipeLines LP's board and our board.

Net cash provided by operations

year ended December 31 (millions of $)	2015	2014	2013
Funds generated from operations	**4,513**	4,268	4,000
Increase in operating working capital	**(398)**	(189)	(326)
Net cash provided by operations	**4,115**	4,079	3,674

Funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations excluding the timing effects of working capital changes. See page 10 for more information about non-GAAP measures. The increase in 2015 compared to 2014 was driven by the increase in comparable earnings (as discussed in Financial highlights on page 19) adjusted for the following non-cash items: decreased deferred income tax expense, increased depreciation, higher equity AFUDC income and lower equity earnings. Funds generated from operations also reflected higher distributed earnings from equity investments, primarily from Bruce Power and our U.S. natural gas pipelines.

At December 31, 2015, our current liabilities were higher than our current assets, leaving us with a working capital deficit of $3.4 billion. This short-term deficiency is considered to be in the normal course of a growing business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- our access to capital markets
- approximately $7 billion of unutilized unsecured credit facilities.

Comparable distributable cash flow

year ended December 31 (millions of $)	2015	2014	2013
Net cash provided by operations	**4,115**	4,079	3,674
Increase in operating working capital	**398**	189	326
Funds generated from operations	**4,513**	4,268	4,000
Distributions in excess of equity earnings	**226**	159	128
Preferred share dividends paid	**(92)**	(94)	(71)
Distributions paid to non-controlling interests	**(224)**	(178)	(166)
Maintenance capital expenditures including equity investments	**(937)**	(781)	(573)
Distributable cash flow	**3,486**	3,374	3,318
Specific items impacting distributable cash flow (net of tax):			
Restructuring costs	**60**	—	—
Niska contract termination	**—**	32	—
NEB 2013 Decision – 2012	**—**	—	(84)
Comparable distributable cash flow	**3,546**	3,406	3,234
Comparable distributable cash flow per common share	**$5.00**	$4.81	$4.57

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. The increases from 2014 to 2015 as well as 2013 to 2014 were driven by increases in funds generated from operations, as described above, partially offset by higher maintenance capital expenditures primarily on ANR in 2015, and the Canadian Mainline and the NGTL System in 2014 and 2013. See page 10 for more information on non-GAAP measures we use.

Maintenance capital expenditures on our Canadian regulated natural gas pipelines was $347 million in 2015, $355 million in 2014 and $236 million in 2013 which contributed to their respective rate bases and net income.

Net cash used in investing activities

year ended December 31 (millions of $)	2015	2014	2013
Capital spending			
Capital expenditures	**(3,918)**	(3,489)	(4,264)
Capital projects in development	**(511)**	(848)	(488)
	(4,429)	(4,337)	(4,752)
Contributions to equity investments	**(493)**	(256)	(163)
Acquisitions, net of cash acquired	**(236)**	(241)	(216)
Proceeds from sale of assets, net of transaction costs	**—**	196	—
Distributions in excess of equity earnings	**226**	159	128
Deferred amounts and other	**322**	335	(117)
Net cash used in investing activities	**(4,610)**	(4,144)	(5,120)

Our 2015 capital expenditures were incurred primarily for:

- the expansion of the NGTL System
- construction of Mexico pipelines
- capital additions to our ANR pipeline
- construction of the Northern Courier pipeline
- expansion of the Canadian Mainline
- construction of the Napanee power generating facility.

Our 2014 capital expenditures were incurred primarily for expanding our NGTL System, construction of our Mexican pipelines, construction of the Houston Lateral and Tank Terminal and expansion of the ANR pipeline.

Our 2013 capital expenditures were incurred primarily for construction of the Gulf Coast project, expanding our NGTL System and construction of our Mexican pipelines.

Costs incurred on capital projects in development in 2015, 2014 and 2013 primarily related to the Energy East Pipeline and LNG pipeline projects.

Contributions to equity investments increased in 2015 compared to 2014 and 2014 compared to 2013 primarily due to our investments in Bruce Power and in Grand Rapids Phase 1 pipeline.

In 2015, we acquired an additional ownership interest in Bruce Power. See Significant events in the Energy section for more information. In 2014, we acquired an additional four solar facilities in Ontario and sold Cancarb and its related power generation facilities. In 2013, we acquired our first four solar facilities.

The increases from 2014 to 2015 and 2013 to 2014 in distributions in excess of equity earnings are primarily due to distributions from Bruce A.

Net cash provided by/(used in) financing activities

year ended December 31 (millions of $)	2015	2014	2013
Notes payable (repaid)/issued, net	**(1,382)**	544	(492)
Long-term debt issued, net of issue costs	**5,045**	1,403	4,253
Long-term debt repaid	**(2,105)**	(1,069)	(1,286)
Junior subordinated notes issued, net of issue costs	**917**	—	—
Dividends and distributions paid	**(1,762)**	(1,617)	(1,522)
Common shares issued	**27**	47	72
Common shares repurchased	**(294)**	—	—
Preferred shares issued, net of issue costs	**243**	440	585
Partnership units of subsidiary issued, net of issue costs	**55**	79	384
Preferred shares of subsidiary redeemed	**—**	(200)	(200)
Net cash provided by/(used in) financing activities	**744**	(373)	1,794

Long-term debt issued

(millions of $) Entity	Issue date	Type	Maturity date	Amount	Interest rate
TCPL	January 2016	Senior Unsecured Notes	January 2026	US$850	4.875%
	January 2016	Senior Unsecured Notes	January 2019	US$400	3.125%
	November 2015	Senior Unsecured Notes	November 2017	US$1,000	1.625%
	October 2015	Medium-Term Notes	November 2041	$400	4.55%
	July 2015	Medium-Term Notes	July 2025	$750	3.30%
	March 2015	Senior Unsecured Notes	March 2045	US$750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US$500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US$250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US$1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US$625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US$625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US$500	Floating
	July 2013	Medium-Term Notes	July 2023	$450	3.69%
	July 2013	Medium-Term Notes	November 2041	$300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US$750	0.75%
TC PipeLines, LP	September 2015	Unsecured Term Loan	October 2018	US$170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US$350	4.375%
	July 2013	Unsecured Term Loan Facility	July 2018	US$500	Floating
Gas Transmission Northwest LLC	June 2015	Unsecured Term Loan	June 2019	US$75	Floating

Junior subordinated notes issued

(millions of $) Entity	Issue date	Type	Maturity date	Amount	Interest rate
TCPL	May 2015	Junior subordinated notes[1]	May 2075	US$750	5.875%[2]

1 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL and are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

2 The Junior subordinated notes were issued to TransCanada Trust. The interest rate is fixed at 5.875 per cent per annum and will reset starting May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum.

TransCanada Trust (the Trust), a financing trust subsidiary wholly owned by TCPL, issued US$750 million Trust Notes - Series 2015-A (Trust Notes) to third party investors with a fixed interest rate of 5.625 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to us in US$750 million junior subordinated notes of TCPL at a rate of 5.875 per cent which includes a 0.25 per cent administration charge. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in our financial statements as TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances, (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with other outstanding first preferred shares of TCPL. Further details regarding the terms of the Trust Notes and the related agreements entered into by TransCanada and TCPL can be found in the prospectus in respect of the Trust Notes and other documents filed under the Trust's profile on SEDAR at www.sedar.com.

Long-term debt retired

(millions of $) Entity	Retirement date	Type	Amount	Interest rate
TCPL	January 2016	Senior Unsecured Notes	US$750	0.75%
	August 2015	Debentures	$150	11.90%
	June 2015	Senior Unsecured Notes	US$500	3.40%
	March 2015	Senior Unsecured Notes	US$500	0.875%
	January 2015	Senior Unsecured Notes	US$300	4.875%
	June 2014	Debentures	$125	11.10%
	February 2014	Medium-Term Notes	$300	5.05%
	January 2014	Medium-Term Notes	$450	5.65%
	August 2013	Senior Unsecured Notes	US$500	5.05%
	June 2013	Senior Unsecured Notes	US$350	4.00%
Gas Transmission Northwest LLC	June 2015	Senior Unsecured Notes	US$75	5.09%
Nova Gas Transmission Ltd.	June 2014	Debentures	$53	11.20%

Preferred share issuance, redemption and conversion

On February 1, 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum Such rate will reset every five years.

In June 2015, holders of 5.5 million Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.28 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 3 preferred shares was reset for five years at 2.152 per cent per annum representing the sum of the applicable Government of Canada five year bond rate plus 1.28 per cent. Such rate will reset every five years.

In March 2015, we completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $250 million. The Series 11 preferred shareholders will have the right to convert their Series 11 preferred shares into Series 12 cumulative redeemable first preferred shares on November 30, 2020 and on November 30 of every fifth year thereafter. The holders of Series 12 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 2.96 per cent. The fixed dividend rate on the Series 11 preferred shares was set for five years at 3.8 per cent per annum or $0.95 per share.

The following table summarizes the impact of the above issuance and conversion of preferred shares discussed above:

(millions of Canadian $, unless noted otherwise)	Number of shares issued and outstanding (thousands)	Current yield[1]	Annual dividend per share[1]	Redemption price per share[2]	Redemption and conversion option date	Right to convert into
Cumulative first preferred shares						
Series 3	8,533	2.152%	$0.538	$25.00	June 30, 2020	Series 4
Series 4	5,467	Floating[3]	Floating	$25.00	June 30, 2020	Series 3
Series 5	12,715	2.263%	$0.56575	$25.00	January 30, 2021	Series 6
Series 6	1,285	Floating[4]	Floating	$25.00	January 30, 2021	Series 5
Series 11	10,000	3.8%	$0.95	$25.00	November 30, 2020	Series 12

1 Holders of the cumulative redeemable first preferred shares set out in this table are entitled to receive a fixed cumulative quarterly preferred dividend, as and when declared by the Board with the exception of Series 4 and Series 6 preferred shares. The holders of Series 4 and Series 6 preferred shares are entitled to receive a quarterly floating rate cumulative preferred dividend as and when declared by the Board.

2 We may, at our option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the redemption option date and on every fifth anniversary date thereafter. In addition, Series 2 and Series 4 preferred shares are redeemable by us at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date, in which case they are redeemable at $25.00 per share plus all accrued and unpaid dividends.

3 Commencing December 31, 2015, the floating quarterly dividend rate for the Series 4 preferred shares is 1.778 per cent and will reset every quarter going forward.

4 Commencing February 1, 2016, the floating quarterly dividend rate for the Series 6 preferred shares is 2.037 per cent and will reset every quarter going forward.

In December 2014, Series 1 shareholders elected to convert 12.5 million of our 22 million outstanding Series 1 cumulative redeemable first preferred shares, on a one-for-one basis into Series 2 floating-rate cumulative redeemable first preferred shares. The Series 1 shares will yield an annual fixed dividend rate of 3.266 per cent, paid on a quarterly basis, for the five-year period which began on December 31, 2014. The Series 2 shares will pay a floating quarterly dividend at an annualized rate equal to the sum of the 90-day Government of Canada treasury bill rate and 1.92 per cent for the five-year period which began on December 31, 2014.

In March 2014, TCPL redeemed all four million of its Series Y preferred shares 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 they carried an aggregate of $11 million in annualized dividends.

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 sum of the then 90-day Government of Canada treasury bill rate and 2.35 per cent.

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

Common shares repurchased

On November 19, 2015, we announced that the TSX approved our NCIB, which allows for the repurchase and cancellation of up to 21.3 million of our common shares, representing three per cent of our issued and outstanding common shares, between November 23, 2015 and November 22, 2016, at prevailing market prices plus brokerage fees, or such other prices as may be permitted by the TSX.

The following table provides the information related to shares repurchased to date under the NCIB:

at February 10, 2016 (millions of $, except per share data)	
Number of common shares repurchased[1]	**7.1**
Weighted-average price per common share[2]	**$43.36**
Amount of repurchase	**$307**

1 Includes repurchases of common shares pursuant to private agreements between us and third-parties.
2 Includes brokerage fees.

TC PipeLines, LP

At-the-market equity issuance program

In August 2014, TC PipeLines, LP initiated its at-the-market equity issuance program (ATM program) under which it is authorized to offer and sell common units having an aggregate offering price of up to US$200 million. Our ownership interest in TC PipeLines, LP will decrease as a result of equity issuances under the ATM program.

From January 1 to December 31, 2015, 0.7 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$44 million.

From August 2014 until December 31, 2014, 1.3 million common units were issued under the ATM program generating net proceeds of approximately US$73 million.

Asset drop downs

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

In April 2015, we closed the sale of our remaining 30 per cent interest in GTN to TC PipeLines, LP, for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

In October 2014, we closed the sale of our remaining 30 per cent interest in Bison to TC PipeLines, LP, for cash proceeds of US$215 million.

In July 2013, we closed the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million representing 45 per cent of GTN's debt.

Credit facilities

We have committed, revolving credit facilities that primarily support our commercial paper programs. In addition, we have demand credit facilities that are used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At December 31, 2015, we had $8.9 billion (2014 - $6.7 billion) in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	Description	Matures
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility that supports TCPL's Canadian commercial paper program	December 2020
US$1 billion	US$1 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility that supports TCPL's U.S. commercial paper program	December 2016
US$0.5 billion	US$0.5 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility that is used for TCPL USA general corporate purposes	December 2016
US$1.5 billion	US$1.5 billion	TAIL/TCPM	Committed, syndicated, revolving, extendible credit facility that supports the joint TAIL/TCPM commercial paper program in the U.S.	December 2016
$1.7 billion	$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand

At December 31, 2015, our operated affiliates had an additional $0.6 billion (2014 - $0.4 billion) of undrawn capacity on committed credit facilities.

Contractual obligations

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee retirement and post-retirement benefit plans.

Payments due (by period)

at December 31, 2015 (millions of $)	Total	less than 12 months	12 – 36 months	37 – 60 months	more than 60 months
Notes payable	1,218	1,218	—	—	—
Long-term debt (includes junior subordinated notes)	34,061	2,547	5,529	3,029	22,956
Operating leases (future payments for various premises, services and equipment, less sub-lease receipts)	1,561	308	554	389	310
Purchase obligations	3,759	2,397	853	150	359
Other long-term liabilities reflected on the balance sheet	96	8	18	19	51
	40,695	6,478	6,954	3,587	23,676

Long-term debt

At the end of 2015, we had $31.6 billion of long-term debt and $2.4 billion of junior subordinated notes outstanding, compared to $24.8 billion of long-term debt and $1.2 billion of junior subordinated notes at December 31, 2014.

Total notes payable were $1.2 billion at the end of 2015 compared to $2.5 billion at the end of 2014.

We attempt to spread out the maturity profile of our debt. The weighted-average maturity of our long-term debt is 16 years, with the majority maturing beyond five years.

Interest payments

At December 31, 2015, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2015 (millions of $)	Total	less than 12 months	12 – 36 months	37 – 60 months	more than 60 months
Long-term debt	21,786	1,612	3,022	2,625	14,527
Junior subordinated notes	8,229	149	298	298	7,484
	30,015	1,761	3,320	2,923	22,011

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 25 years.

Our commitments under the Alberta PPAs are considered operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Fixed payments under these PPAs have been included in our summary of future obligations. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. Our share of power purchased under the PPAs in 2015 was $348 million (2014 – $391 million; 2013 – $242 million).

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)[1]

at December 31, 2015 (millions of $)	Total	less than 12 months	12 – 36 months	37 – 60 months	more than 60 months
Natural Gas Pipelines					
Transportation by others[2]	286	91	153	24	18
Capital spending[3]	901	887	14	—	—
Other	4	2	2	—	—
Liquids Pipelines					
Capital spending[3]	765	563	201	1	—
Other	38	6	12	9	11
Energy					
Commodity purchases	460	262	188	10	—
Capital spending[3]	644	489	155	—	—
Other[4]	594	69	99	97	329
Corporate					
Information technology and other	67	28	29	9	1
	3,759	2,397	853	150	359

1 The amounts in this table exclude funding contributions to our pension plans.
2 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude commodity charges incurred when volumes flow.
3 Amounts include capital expenditures and capital projects under development, are estimates and are subject to variability based on timing of construction and project enhancements.
4 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, use of natural gas storage facilities, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for transportation.

Outlook

We are developing quality projects under our long-term $58.6 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements, and once completed, are expected to generate significant growth in earnings and cash flow.

Our $58.6 billion capital program is comprised of $13.4 billion of near-term projects and $45.2 billion of commercially secured medium and longer-term projects, each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow and a combination of funding options including:

- senior debt
- project financing
- preferred shares
- hybrid securities
- additional drop downs of our U.S. natural gas pipeline assets to TC PipeLines, LP
- asset sales
- potential involvement of strategic or financial partners
- portfolio management

Additional financing alternatives available include common equity through DRP or, lastly, discrete equity issuances.

GUARANTEES

Bruce Power

We and our partner, OMERS, have each severally guaranteed some of Bruce Power contingent financial obligations related to a lease agreement and contractor and supplier services. The Bruce Power guarantees have terms to 2018 except for one guarantee with no termination date that has no exposure associated with it.

At December 31, 2015, our share of the potential exposure under the Bruce Power guarantees was estimated to be $88 million. The carrying amount of these guarantees was estimated to be $2 million. Our exposure under certain of these guarantees is unlimited.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) the financial performance of these entities relating mainly to redelivery of natural gas, PPA payments and the payment of liabilities. The guarantees have terms ranging to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2015 to be a maximum of $139 million. The carrying amount of these guarantees was $24 million, and is included in other long-term liabilities. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2016, we expect to make funding contributions of approximately $70 million for the defined benefit pension plans, approximately $7 million for the other post-retirement benefit plans and approximately $37 million for the savings plan and defined contribution pension plans. In addition, we expect to provide a $33 million letter of credit to the Canadian defined benefit plan for the funding of solvency requirements.

In 2015, we made funding contributions of $96 million to our defined benefit pension plans, $6 million for the other post-retirement benefit plans and $41 million for the savings plan and defined contribution pension plans. We also provided a $33 million letter of credit to a defined benefit plan in lieu of cash funding.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2016. Based on current market conditions, we expect funding requirements for these plans to approximate 2015 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans increased to $146 million in 2015 from $115 million in 2014, mainly due to a lower discount rate used to measure the benefit obligation.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

The following is a summary of general risks that affect our company. You can find risks specific to each operating business segment in the business segment discussions.

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We build risk assessment into our decision-making processes at all levels.

The Board's Governance Committee oversees our risk management activities, which includes ensuring that there are appropriate management systems in place to manage our risks, including adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk: the Audit Committee oversees management's role in monitoring financial risk, the Human Resources Committee oversees executive resourcing and compensation, organizational capabilities and compensation risk, and the Health, Safety and Environment Committee oversees operational, safety and environmental risk through regular reporting from management.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

Operational risks

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror, or natural disasters and other catastrophic events.	Decrease in revenues, increase in operating costs or legal proceedings or other expenses all of which could reduce our earnings. Losses not covered by insurance could have an adverse effect on operations, cash flow and financial position.	We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We also have a Business Continuity Program that determines critical business processes and develops resumption plans to ensure process continuity. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances.
Reputation and relationships		
Our reputation and relationship with Indigenous communities and our stakeholders including other communities, landowners, governments and government agencies, and environmental non-governmental organizations is very important.	These Indigenous communities and stakeholders can have a significant impact on our operations, infrastructure development and overall reputation.	Our Stakeholder Engagement Framework is our formal commitment to stakeholder engagement. Our four core values – integrity, collaboration, responsibility and innovation – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders. Additionally, our Aboriginal Relations and Native American Relations Policies guide our engagement with Indigenous communities.
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Under some contracts, we share the cost of execution risks with customers, in exchange for the potential benefit they will realize when the project is finished.

Risk and Description	Impact	Monitoring and Mitigation
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a cyber security awareness program for employees.

Pipeline abandonment costs

The NEB's LMCI is an NEB-approved initiative that requires all Canadian pipeline companies regulated by the NEB to set aside funds to cover future pipeline abandonment costs.

Effective January 2015, funds to cover future abandonment costs are collected through an abandonment surcharge applied to monthly tolls set-aside and invested in a Government of Canada fixed income portfolio. A status report for each trust fund disclosing the 2015 year-end balance and audited financial statements will be filed with the NEB in April 2016.

Health, safety and environment

The Health, Safety and Environment committee of TransCanada's Board of Directors (the Board) monitors compliance with our HSE corporate commitment statement through regular reporting from management. We have an integrated HSE Management System that is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

The HSE Management System is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements and other internal management systems. It follows a continuous improvement cycle.

The committee reviews HSE performance including risk management three times a year. It receives detailed reports on:

- overall HSE corporate governance and performance
- operational performance and preventive maintenance metrics
- asset integrity programs
- security and emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- developments in and compliance with applicable legislation and regulations.

The committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans emanating from internal and third party audits.

The safety and integrity of our existing and newly-developed infrastructure is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. In 2015, we spent $803 million for pipeline integrity on the natural gas and liquids pipelines we operate, an increase of $253 million over 2014 primarily due to an increase of in-line pipeline inspections and related maintenance projects on all systems as well as an increased amount of pipe replacement required due to population encroachment on the pipelines. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are generally treated on a flow-through basis and, as a result, these expenditures have minimal impact on our earnings. Under the Keystone Pipeline System contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures generally have no impact on our earnings. We continue to have industry leading safety performance in 2015.

Our Energy operations spending associated with process safety and our various integrity programs is used to minimize risk to employees and the public, process equipment, the surrounding environment, and to prevent disruptions to serving the electrical needs of our customers, within the footprint of each facility.

Spending associated with public safety on Energy assets is focused primarily on our hydro dams and associated equipment.

Our main environmental risks are:

- air and GHG emissions
- product releases, including crude oil and natural gas, into the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- compliance with corporate and regulatory policies and requirements and new regulations.

As described in the Business interruption section, above, we have a set of procedures in place to manage our response to natural disasters which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency Preparedness and Response Program, are designed to help protect the health and safety of our employees, minimize risk to the public and limit any operational impacts on the environment.

Environmental compliance and liabilities

Our facilities are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, wastewater discharges and waste management. Our facilities are required to obtain and comply with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders affecting future operations.

Through our Environmental Management Program we continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are potentially large or uncertain, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations.

Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

It is not possible to estimate the amount and timing of all our future expenditures related to environmental matters because:

- environmental laws and regulations (and interpretation and enforcement of them) change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2015, we had accrued approximately $32 million related to these obligations (2014 - $31 million). This represents the amount that we have estimated that we will need to manage our currently known environmental liabilities. We believe that we have considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us to set aside additional amounts. We adjust this reserve quarterly to account for changes in liabilities.

Greenhouse gas emissions regulation risk

We own assets and have business interests in a number of regions where there are regulations to address industrial GHG emissions. We have procedures in place to comply with these regulations, including:

- under the SGER in Alberta, established industrial facilities with GHG emissions above a certain threshold have to reduce their emissions below an intensity baseline. Our Sundance and Sheerness PPA facilities and NGTL System facilities are subject to this regulation. We recover compliance costs on the NGTL System through the tolls our customers pay. A portion of the compliance costs for Sundance and Sheerness are recovered through market pricing and hedging activities. A new climate change policy, the Climate Leadership Plan (CLP), was announced by the Alberta government in the fall of 2015 that has the objective of positioning the provincial economy to be less carbon intensive. Our internal processes and procedures for managing changing regulations such as the CLP are mature. The potential new costs and business opportunities that come with the Alberta CLP are within the bounds of our previously expected changes to GHG regulation. We have been actively managing its exposure to the existing and newly-announced Alberta carbon pricing policies to minimize the impact.
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs for our compressor and meter stations through the tolls our customers pay.
- U.S. northeastern states that are members of the RGGI have implemented a CO_2 cap-and-trade program for electricity generators. This program applies to both the Ravenswood and Ocean State Power generation facilities.
- Québec's *Regulation Respecting a Cap-and-Trade System for Greenhouse Gas Emission Allowances* came into force in 2011. Bécancour has been required to cover its GHG emissions since 2013. As per the regulations, the government allocates free emission units for the majority of Bécancour's compliance requirements. The remaining requirements were met with GHG instruments purchased at auctions or secondary markets. The costs of these emissions units were recovered through commercial contracts. The pipeline facilities in Québec are also covered under this regulation and have purchased compliance instruments.
- in 2013, California implemented a cap-and-trade program for industrial emitters of GHGs, including electricity importers. We have costs associated with the program from our power marketing activities.

We recorded $59 million of expenses under these programs in 2015 (2014 - $54 million).There are federal, regional, state and provincial initiatives currently in development. While economic events may continue to affect the scope and timing of new regulations, we anticipate that most of our facilities will be subject to future regulations to manage industrial GHG emissions.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in energy infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices and foreign exchange and interest rates which may affect our earnings and the value of the financial instruments we hold.

We use derivative contracts to assist in managing our exposure to market risk, including:

- forwards and futures contracts – agreements to buy or sell a financial instrument or commodity at a specified price and date in the future. We use foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms. We use interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices

- options – agreements that give the purchaser the right (but not the obligation) to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. We use option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

We assess contracts we use to manage market risk to determine whether all, or a portion of it, meets the definition of a derivative.

Commodity price risk

We are exposed to changes in commodity prices which may affect our earnings. We use several strategies to reduce this exposure, including:

- committing a portion of expected power supply to fixed price sales contracts of varying terms while reserving a portion of our unsold power supply to mitigate operational and price risk in our asset portfolio
- purchasing a portion of the natural gas we need to fuel our natural gas-fired power plants in advance or entering into contracts that base the sale price of our electricity on the cost of the natural gas, effectively locking in a margin
- meeting our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices
- using derivative instruments to enter into offsetting or back-to-back positions to manage commodity price risk created by certain fixed and variable prices in arrangements for different pricing indices and delivery points.

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, this exposure increases. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt of our foreign operations 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

	2015	**1.28**
	2014	1.10
	2013	1.03

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by interest on U.S. dollar-denominated long-term debt, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 10 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2015**	**2014**	**2013**
U.S. and International Natural Gas Pipelines comparable EBIT	**738**	630	542
U.S. Liquids Pipelines comparable EBIT	**640**	570	389
U.S. Power comparable EBIT	**313**	269	216
Interest on U.S. dollar-denominated long-term debt	**(911)**	(854)	(766)
Capitalized interest on U.S. dollar-denominated capital expenditures	**109**	154	219
U.S. non-controlling interests and other	**231**	(234)	(196)
	1,120	535	404

Derivatives designated as a net investment hedge

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 or principal amounts for the derivatives designated as a net investment hedge were as follows:

at December 31 (millions of $)	2015 Fair value[1]	2015 Notional or principal amount	2014 Fair value[1]	2014 Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2]	**(730)**	**US 3,150**	(431)	US 2,900
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**50**	**US 1,800**	(28)	US 1,400
	(680)	**US 4,950**	(459)	US 4,300

1 Fair values equal carrying values.

2 Consolidated net income in 2015 included net realized gains of $8 million (2014 – gains of $21 million) related to the interest component of cross-currency swap settlements.

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

at December 31 (millions of $)	2015	2014
Carrying value	**23,000 (US 16,600)**	17,000 (US 14,700)
Fair value	**23,800 (US 17,200)**	19,000 (US 16,400)

Counterparty credit risk

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

- accounts receivable
- portfolio investments
- the fair value of derivative assets
- cash and notes receivable.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts
- using contract netting arrangements and obtaining financial assurances, such as guarantees and letters of credit or cash, when we believe it is necessary.

There is no guarantee that these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. We had no significant credit losses in 2015 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $248 million (US$179 million) at December 31, 2015 with one counterparty (2014 - $258 million (US$222 million)). This amount is secured by a guarantee from the counterparty's parent company and is expected to be fully collectible.

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.

For our Canadian regulated gas pipeline assets, counterparty credit risk is managed through application of tariff provisions as approved by the NEB.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow for a 12 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.

See page 82 Financial condition for more information about our liquidity.

Dealing with legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position, results of operations or liquidity. Other than the Keystone XL legal proceedings described on page 54, we are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position, results of operations or liquidity.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Under the supervision and with the participation of management, including our President and CEO and our CFO, we carried out quarterly evaluations of the effectiveness of our disclosure controls and procedures, including for the period ended December 31, 2015, as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management’s annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2015 based on the criteria described in “Internal Control - Integrated Framework” issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2015, the internal control over financial reporting was effective.

Our internal control over financial reporting as ofDecember 31, 2015 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in this document.

CEO and CFO Certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2015 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

Changes in internal control over financial reporting

There has been no change in our internal control over financial reporting that occurred during the year covered by this annual report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain 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 judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements from those estimates.

Rate-regulated accounting

Under GAAP, an asset qualifies to use RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines and certain liquids pipelines projects we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be refunded through customer rates in future periods.

Regulatory assets and liabilities

at December 31 (millions of $)	2015	2014
Regulatory assets		
Long-term assets	**1,184**	1,297
Short-term assets (included in Other current assets)	**85**	16
Regulatory liabilities		
Long-term liabilities	**1,159**	263
Short-term liabilities (included in Accounts payable and other)	**44**	30

Impairment of long-lived assets and goodwill

We review long-lived assets (such as plant, property and equipment) and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value and we calculate and record an impairment loss to recognize this.

In 2015, the following impairments were recorded:

- a $2,891 million after-tax charge on the carrying value of our investment in the Keystone XL project
- a loss of $43 million after tax relating to certain Energy turbine equipment.

Keystone XL impairment

At December 31, 2015, in connection with the denial of the U.S. Presidential permit, we evaluated our $4.3 billion investmetin Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after tax). The impairment charge was based on the excess of the carrying value over the estimated fair value of$621 million.

at December 31, 2015	Estimated	Impairment charge	
(millions of $)	fair value	Pre-tax	After-tax
Plant and equipment	**463**	**1,460**	**1,391**
Terminals, including Keystone Hardisty Terminal	**158**	**274**	**219**
Intangible assets	**—**	**1,150**	**737**
Capitalized interest	**—**	**725**	**488**
Future cancellation costs	**—**	**77**	**56**
	621	**3,686**	**2,891**

The estimated fair value of $463 million on plant and equipment was based on an expected price that would be received to sell the assets in their current condition. An independent third party evaluation was utilized in the assessment of the fair value of these assets. Key assumptions used in the determination of selling price included an estimated two year disposal period and the current weak energy market conditions. Various outcomes were also considered, including alternate uses for the remaining assets. Depending on the outcomes of sales and alternate uses for the assets, the value realized may be different than what has been estimated. The $158 million fair value of the terminals was estimated using a risk-adjusted discounted cash flow approach as a measure of fair value and considered alternative independent utility of these assets. We recorded a full impairment charge on capitalized interest and other intangible assets as these costs are no longer probable to be recovered. The impairment charge also included certain cancellation fees that will be incurred in the future if the project is ultimately abandoned.

Energy Turbine Impairment

Following the evaluation of specific capital project opportunities in 2015, it was determined that the carrying value of certain Energy turbine equipment was not fully recoverable. These turbines had been previously purchased for a power development project that did not proceed. Various other projects have recently been evaluated for possible use of this equipment and we have determined there is not an appropriate operation or project in which we currently expect to economically utilize this asset. As a result, at December 31, 2015, we recognized a non-cash impairment charge of $59 million ($43 million after tax) on the excess of the carrying value over the fair value of the turbines, which was determined using a third party valuation based on a comparison to similar assets available for sale in the market.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We first assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit to its book value, including its goodwill. If fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value we calculated in the first step. If the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We base these valuations on our projections of future cash flows, which involves making estimates and assumptions about:

- discount rates
- commodity and capacity prices
- market supply and demand assumptions
- growth opportunities
- output levels
- competition from other companies
- regulatory changes.

If our assumptions change significantly, our requirement to record an impairment charge could also change.

The estimated fair value of Great Lakes natural gas transportation business exceeded its carrying value by less than 10 per cent using a discounted cash flow analysis. Despite the recent improvement in income from Great Lakes, its long term value has been adversely impacted by the changing natural gas flows in its market region as well as a change in our view of the strategic alternatives to increase utilization of Great Lakes. As a result, we reduced forecasted cash flows from the reporting unit for the next ten years as compared to those utilized in previous impairment tests. There is a risk that continued reductions in future cash flow forecasts and adverse changes in key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes.

Our share of the goodwill related to Great Lakes, netof non-controlling interests, was US$386 million at December 31, 2015 (2014 – US$243 million). The increase in our share of goodwill is a result of the impairment charge of US$199 million recorded at the TC PipeLines, LP level on its equity method goodwill related to Great Lakes. On a consolidated basis, our carrying value of our investment in Great Lakes is proportionately lower compared to the 46.45 per cent owned through TC PipeLines, LP. As a result, the estimated fair value of Great Lakes exceeded our consolidated carrying value and no impairment was recorded in 2015.

Our assumptions of ANR's projected future cash flows would be impacted should ANR not reach a new settlement or other positive outcome through its Section 4 rate case proceeding. An adverse outcome could result in future impairment of a portion of the goodwill balance relating to ANR. The goodwill balance related to ANR was US$1.9 billion at December 31, 2015 (2014 - US$1.9 billion).

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the ARO in our financial statements.

We cannot determine when we will retire many of our hydro-electric power plants, oil pipelines, natural gas pipelines and transportation facilities and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

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 normal 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 and junior subordinated notes has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangibles 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.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

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 and are designated for hedge accounting treatment. 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.

The majority of 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 year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives 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.

Balance sheet presentation of derivative instruments

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

at December 31 (millions of $)	2015	2014
Other current assets	**442**	409
Intangible and other assets	**168**	93
Accounts payable and other	**(926)**	(749)
Other long-term liabilities	**(625)**	(411)
	(941)	(658)

Anticipated timing of settlement – derivative instruments

The anticipated timing of settlement for derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2015 (millions of $)	Total fair value	2016	2017 and 2018	2019 and 2020
Derivative instruments held for trading				
Assets	456	330	113	13
Liabilities	(630)	(499)	(124)	(7)
Derivative instruments in hedging relationships				
Assets	154	112	28	14
Liabilities	(921)	(427)	(435)	(59)
	(941)	(484)	(418)	(39)

Unrealized and realized (losses)/gains of derivative instruments

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

year ended December 31 (millions of $)	2015	2014
Derivative instruments held for trading[1]		
Amount of unrealized losses in the year		
Commodities	**(37)**	(40)
Foreign exchange	**(21)**	(20)
Amount of realized losses in the year		
Commodities	**(151)**	(28)
Foreign exchange	**(112)**	(28)
Derivative instruments in hedging relationships[2,3]		
Amount of realized (losses)/gains in the year		
Commodities	**(179)**	130
Interest rate	**8**	4

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell commodities are included net in 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 In 2015, net realized gains on fair value hedges were $11 million (2014 - $7 million) and were included in interest expense.

3 In 2015 and 2014, 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 consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

year ended December 31 (millions of $, pre-tax)	2015	2014
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(92)**	(128)
Foreign exchange	**—**	10
	(92)	(118)
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**128**	(111)
Interest rate[3]	**16**	16
	144	(95)
Losses on derivative instruments recognized in net income (ineffective portion)		
Commodities[2]	**—**	(13)
	—	(13)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within revenues on the consolidated statement of income.
3 Reported within interest expense on the consolidated statement of income.

Credit risk related contingent features of derivative instruments

Derivatives 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). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2015, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $32 million (2014 – $15 million), with collateral provided in the normal course of business of nil (2014 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2015, we would have been required to provide additional collateral of $32 million (2014 – $15 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2015

Derivatives and Hedging

In August 2015, the FASB issued new guidance on the application of the normal purchases and normal sales scope exception to certain electricity contracts within nodal energy markets. The amendments in this update apply to entities that enter into contracts for the purchase or sale of electricity on a forward basis and arrange for transmission through or delivery to a location within a nodal energy market whereby one of the contracting parties incurs charges (or credits) for the transmission of that electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. This new guidance was effective upon issuance, was applied prospectively and did not have a material impact on our consolidated financial statements.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued new guidance which requires that deferred tax assets and liabilities classified as non-current on the balance sheet. The new guidance is effective January 1, 2017, however, since early application is permitted, we elected to retrospectively apply this guidance on January 1, 2015. Application of this new guidance simplified our process in determining deferred tax amounts and our presentation. The application of this amendment resulted in a reclassification of deferred tax assets previously recorded in other current assets and deferred tax liabilities previously recorded in accounts payable and other to non-current deferred income tax assets and liabilities. Prior year amounts have been reclassified to conform to current year presentation.

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what qualifies as a discontinued operation has changed and there are expanded disclosures required. This new guidance was applied prospectively from January 1, 2015 and there was no impact on our consolidated financial statements as a result of applying this new standard.

Future accounting changes

Revenue from contracts with customers

In 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. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are 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.

We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Extraordinary and unusual income statement items

In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from GAAP the concept of extraordinary items. This new guidance is effective from January 1, 2016 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.

Consolidation

In February 2015, the FASB issued new guidance on consolidation analysis. This update requires that entities reevaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance is effective from January 1, 2016 and will be applied retrospectively. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance is effective January 1, 2016 and will be applied retrospectively. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in Intangible and other assets to an offset of their respective debt liabilities.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 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.

Business Combinations

In September 2015, the FASB issued guidance which replaces the requirement that an acquirer in a business combination account for measurement period adjustments retrospectively with a requirement that an acquirer recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amended guidance requires that the acquirer record, in the same period's financial statements as the adjustment was determined, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The new guidance is effective January 1, 2016 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.

RECONCILITATION OF NON-GAAP MEASURES

year ended December 31 (millions of $, except per share amounts)	2015	2014	2013
EBITDA	**1,866**	5,542	4,958
Specific items:			
Keystone XL impairment charge	**3,686**	—	—
TC Offshore loss on sale	**125**	—	—
Restructuring costs	**99**	—	—
Turbine equipment impairment charge	**59**	—	—
Bruce Power merger – debt retirement charge	**36**	—	—
Cancarb gain on sale	**—**	(108)	—
Niska contract termination	**—**	43	—
Gas Pacifico/ INNERGY gain on sale	**—**	(9)	—
NEB 2013 Decision – 2012	**—**	—	(55)
Risk management activities[1]	**37**	53	(44)
Comparable EBITDA	**5,908**	5,521	4,859
Comparable depreciation and amortization	**(1,765)**	(1,611)	(1,472)
Comparable EBIT	**4,143**	3,910	3,387
Other income statement items			
Comparable interest expense	**(1,370)**	(1,198)	(984)
Comparable interest income and other	**184**	112	42
Comparable income taxes	**(903)**	(859)	(662)
Comparable net income attributable to non-controlling interests	**(205)**	(153)	(125)
Preferred share dividends	**(94)**	(97)	(74)
Comparable earnings	**1,755**	1,715	1,584
Specific items (net of tax):			
Keystone XL impairment charge	**(2,891)**	—	—
TC Offshore loss on sale	**(86)**	—	—
Restructuring costs	**(74)**	—	—
Turbine equipment impairment charge	**(43)**	—	—
Alberta corporate income tax rate increase	**(34)**	—	—
Bruce Power merger – debt retirement charge	**(27)**	—	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**199**	—	—
Cancarb gain on sale	**—**	99	—
Niska contract termination	**—**	(32)	—
Gas Pacifico/ INNERGY gain on sale	**—**	8	—
NEB 2013 Decision – 2012	**—**	—	84
Part VI.I income tax adjustment	**—**	—	25
Risk management activities[1]	**(39)**	(47)	19
Net (loss)/income attributable to common shares	**(1,240)**	1,743	1,712
Comparable depreciation and amortization	**(1,765)**	(1,611)	(1,472)
Specific item:			
NEB 2013 Decision – 2012	**—**	—	(13)
Depreciation and amortization	**(1,765)**	(1,611)	(1,485)

year ended December 31 (millions of $, except per share amounts)	2015	2014	2013
Comparable interest expense	**(1,370)**	(1,198)	(984)
Specific item:			
NEB 2013 Decision – 2012	**—**	—	(1)
Interest expense	**(1,370)**	(1,198)	(985)
Comparable interest income and other	**184**	112	42
Specific items:			
NEB 2013 Decision – 2012	**—**	—	1
Risk management activities[1]	**(21)**	(21)	(9)
Interest income and other	**163**	91	34
Comparable income tax expense	**(903)**	(859)	(662)
Specific items:			
Keystone XL impairment charge	**795**	—	—
TC Offshore loss on sale	**39**	—	—
Restructuring costs	**25**	—	—
Turbine equipment impairment charge	**16**	—	—
Bruce Power merger – debt retirement charge	**9**	—	—
Alberta corporate income tax rate increase	**(34)**	—	—
Cancarb gain on sale	**—**	(9)	—
Niska contract termination	**—**	11	—
Gas Pacifico/ INNERGY gain on sale	**—**	(1)	—
NEB 2013 Decision – 2012	**—**	—	42
Part VI.I income tax adjustment	**—**	—	25
Risk management activities[1]	**19**	27	(16)
Income tax expense	**(34)**	(831)	(611)
Comparable earnings per common share	**$2.48**	$2.42	$2.24
Specific items (net of tax):			
Keystone XL impairment charge	**(4.08)**	—	—
TC Offshore loss on sale	**(0.12)**	—	—
Restructuring costs	**(0.10)**	—	—
Turbine equipment impairment charge	**(0.06)**	—	—
Alberta corporate income tax rate increase	**(0.05)**	—	—
Bruce Power merger – debt retirement charge	**(0.04)**	—	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**0.28**	—	—
Cancarb gain on sale	**—**	0.14	—
Niska contract termination	**—**	(0.04)	—
Gas Pacifico/ INNERGY gain on sale	**—**	0.01	—
NEB 2013 Decision – 2012	**—**	—	0.12
Part VI.I Income tax adjustment	**—**	—	0.04
Risk management activities[1]	**(0.06)**	(0.07)	0.02
Net (loss)/income per common share	**($1.75)**	$2.46	$2.42

year ended December 31 (millions of $)	2015	2014	2013
Canadian Power	**(8)**	(11)	(4)
U.S. Power	**(30)**	(55)	50
Natural Gas Storage	**1**	13	(2)
Foreign exchange	**(21)**	(21)	(9)
Income taxes attributable to risk management activities	**19**	27	(16)
Total (losses)/gains from risk management activities	**(39)**	(47)	19

Comparable EBITDA and comparable EBIT by business segment

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

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

year ended December 31, 2013 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	2,907	752	1,407	(108)	4,958
NEB 2013 Decision – 2012	(55)	—	—	—	(55)
Risk management activities	—	—	(44)	—	(44)
Comparable EBITDA	2,852	752	1,363	(108)	4,859
Comparable depreciation and amortization	(1,013)	(149)	(294)	(16)	(1,472)
Comparable EBIT	1,839	603	1,069	(124)	3,387

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2015	Fourth	Third	Second	First
Revenues	**2,851**	**2,944**	**2,631**	**2,874**
Net (loss)/income attributable to common shares	**(2,458)**	**402**	**429**	**387**
Comparable earnings	**453**	**440**	**397**	**465**
Comparable earnings per common share	**$0.64**	**$0.62**	**$0.56**	**$0.66**
Share statistics				
Net (loss)/income per common share – basic and diluted	**($3.47)**	**$0.57**	**$0.60**	**$0.55**
Dividends declared per common share	**$0.52**	**$0.52**	**$0.52**	**$0.52**

2014	Fourth	Third	Second	First
Revenues	2,616	2,451	2,234	2,884
Net income attributable to common shares	458	457	416	412
Comparable earnings	511	450	332	422
Comparable earnings per common share	$0.72	$0.63	$0.47	$0.60
Share statistics				
Net income per common share – basic and diluted	$0.65	$0.64	$0.59	$0.58
Dividends declared per common share	$0.48	$0.48	$0.48	$0.48

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In Natural Gas Pipelines, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' 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 for natural gas and power
- 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.

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.

In fourth quarter 2015, comparable earnings excluded:

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

In third quarter 2015, comparable earnings excluded a charge of $6 million after-tax for severance costs as part of a restructuring initiative to maximize the effectiveness and efficiency of our existing operations.

In second quarter 2015, comparable earnings excluded a $34 million adjustment to income tax expense due to the enactment of an increase in the Alberta corporate income tax rate in June 2015 and a charge of $8 million after-tax for severance costs primarily as a result of the restructuring of our major projects group in response to delayed timelines on certain of our major projects along with a continued focus on enhancing the efficiency and effectiveness of our operations.

In fourth quarter 2014, comparable earnings excluded an $8 million after-tax gain on the sale of Gas Pacifico/INNERGY.

In second quarter 2014, comparable earnings excluded a $99 million after-tax gain on the sale of Cancarb Limited and a $32 million after-tax loss related to the termination of the Niska Gas Storage contract.

FOURTH QUARTER 2015 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2015	2014
Natural Gas Pipelines	**572**	621
Liquids Pipelines	**(3,413)**	230
Energy	**82**	219
Corporate	**(161)**	(43)
Total segmented (losses)/earnings	**(2,920)**	1,027
Interest expense	**(380)**	(323)
Interest income and other	**80**	28
(Loss)/Income before income taxes	**(3,220)**	732
Income tax recovery/(expense)	**646**	(206)
Net (loss)/income	**(2,574)**	526
Net income/(loss) attributable to non-controlling interests	**139**	(43)
Net (loss)/income attributable to controlling interests	**(2,435)**	483
Preferred share dividends	**(23)**	(25)
Net (loss)/income attributable to common shares	**(2,458)**	458
Net (loss)/income per common share – basic and diluted	**($3.47)**	$0.65

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

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

The 2014 results included:

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

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

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

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2015	2014
Net (loss)/income attributable to common shares	**(2,458)**	458
Specific items (net of tax):		
Keystone XL impairment charge	**2,891**	—
TC Offshore loss on sale	**86**	—
Restructuring costs	**60**	—
Turbine equipment impairment charge	**43**	—
Bruce Power merger – debt retirement charge	**27**	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**(199)**	—
Gas Pacifico/ INNERGY gain on sale	**—**	(8)
Risk management activities[1]	**3**	61
Comparable earnings	**453**	511
Net (loss)/income per common share	**($3.47)**	$0.65
Specific items (net of tax):		
Keystone XL impairment charge	**4.08**	—
TC Offshore loss on sale	**0.12**	—
Restructuring costs	**0.08**	—
Turbine equipment impairment charge	**0.06**	—
Bruce Power merger – debt retirement charge	**0.04**	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**(0.28)**	—
Gas Pacifico/ INNERGY gain on sale	**—**	(0.01)
Risk management activities[1]	**0.01**	0.08
Comparable earnings per common share	**$0.64**	$0.72

1

three months ended December 31 (millions of $)	2015	2014
Canadian Power	**(1)**	(11)
U.S. Power	**(8)**	(85)
Natural Gas Storage	**(1)**	9
Foreign exchange	**4**	(12)
Income tax attributable to risk management activities	**3**	38
Total losses from risk management activities	**(3)**	(61)

Comparable EBITDA and comparable EBIT by business segment

three months ended December 31, 2015 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Comparable EBITDA	**984**	**342**	**275**	**(74)**	**1,527**
Depreciation and amortization	**(287)**	**(69)**	**(88)**	**(8)**	**(452)**
Comparable EBIT	**697**	**273**	**187**	**(82)**	**1,075**

three months ended December 31, 2014 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Comparable EBITDA	884	288	385	(36)	1,521
Depreciation and amortization	(272)	(58)	(79)	(7)	(416)
Comparable EBIT	612	230	306	(43)	1,105

Comparable earnings

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

- lower Canadian Mainline incentive earnings
- lower earnings from Canadian Power due to lower realized power prices and PPA volumes from Western Power, lower earnings from Bruce Power due to higher planned outage days and higher operating expenses at Bruce A, partially offset by fewer planned outage days and lower lease expense at Bruce B and lower earnings on sale of unused natural gas transportation from Eastern Power
- higher earnings from Liquids Pipelines due to higher contracted volumes
- higher interest expense due to long-term debt issuances and the ceasing of capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential permit.

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

Highlights by business segment

Natural Gas Pipelines

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

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

Canadian Pipelines

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

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

U.S. and International Pipelines

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

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

Liquids Pipelines

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

Comparable EBITDA for the Keystone Pipeline System increased by $54 million for the three months ended December 31, 2015 compared to the same period in 2014 and was primarily due to higher contracted volumes and a stronger U.S. dollar and its positive effect on the foreign exchange impact.

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

Energy

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

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

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

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

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

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

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

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

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

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

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

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

Comparable EBITDA for Natural Gas Storage and Other decreased by $5 million for the three months ended December 31, 2015 compared to the same period in 2014 mainly due to decreased proprietary revenue as a result of lower realized natural gas storage price spreads.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
km	Kilometres
KW-M	Kilowatt month
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FID	Final investment decision
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
fracking	Hydraulic fracturing. A method of extracting natural gas from shale rock
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes rate base as well as assets under construction
LNG	Liquefied natural gas
NEB 2014 Decision	In response to the RH-01-2014 Decision on the Canadian Mainline's 2015-2030 Tolls Application.
OM&A	Operating, maintenance and administration
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
rate base	Our annual average investment used
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
ASU	Accounting Standards Update
DRP	Dividend reinvestment plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
GAAP	U.S. generally accepted accounting principles
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
Specific Item	Items we believe are significant but not reflective of our underlying operations in the period

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOS	Department of State (U.S.)
EPA	Environmental Protection Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
IESO	Independent Electricity System Operator
ISO	Independent System Operator
LMCI	Land Matters Consultation Initiative (Canada)
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
OPA	Ontario Power Authority (Canada)
OPEC	Organization of the Petroleum Exporting Countries
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations

Management's report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2015 to that in 2014, and highlights significant changes between 2014 and 2013. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control (COSO) – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2015, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.



Russell K. Girling
President and
Chief Executive Officer



Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 10, 2016

Independent Auditors' Report of Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA CORPORATION

We have audited the accompanying consolidated financial statements of TransCanada Corporation, which comprise the Consolidated balance sheets as at December 31, 2015 and December 31, 2014, the Consolidated statements of income, comprehensive income, cash flows and equity for each of the years in the three-year period ended December 31, 2015, and Notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the Consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada Corporation as at December 31, 2015 and December 31, 2014, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2015 in accordance with U.S. generally accepted accounting principles.

OTHER MATTER

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransCanada Corporation's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 10, 2016 expressed an unmodified (unqualified) opinion on the effectiveness of TransCanada Corporation's internal control over financial reporting.



Chartered Professional Accountants

Calgary, Canada

February 10, 2016

Report of Independent Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA CORPORATION

We have audited TransCanada Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). TransCanada Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, TransCanada Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the Consolidated balance sheets of TransCanada Corporation as of December 31, 2015 and December 31, 2014, and the related Consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2015, and our report dated February 10, 2016 expressed an unmodified (unqualified) opinion on those Consolidated financial statements.



Chartered Professional Accountants

Calgary, Canada

February 10, 2016

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2015	2014	2013
Revenues			
Natural Gas Pipelines	**5,383**	4,913	4,497
Liquids Pipelines	**1,879**	1,547	1,124
Energy	**4,038**	3,725	3,176
	11,300	10,185	8,797
Income from Equity Investments (Note 8)	**440**	522	597
Operating and Other Expenses			
Plant operating costs and other	**3,250**	2,973	2,674
Commodity purchases resold	**2,237**	1,836	1,317
Property taxes	**517**	473	445
Depreciation and amortization	**1,765**	1,611	1,485
Asset impairment charges (Note 7)	**3,745**	—	—
	11,514	6,893	5,921
(Loss)/Gain on Assets Held for Sale/Sold (Notes 6 and 25)	**(125)**	117	—
Financial Charges			
Interest expense (Note 16)	**1,370**	1,198	985
Interest income and other	**(163)**	(91)	(34)
	1,207	1,107	951
(Loss)/Income before Income Taxes	**(1,106)**	2,824	2,522
Income Tax Expense/(Recovery) (Note 15)			
Current	**136**	145	43
Deferred	**(102)**	686	568
	34	831	611
Net (Loss)/Income	**(1,140)**	1,993	1,911
Net Income attributable to non-controlling interests (Note 18)	**6**	153	125
Net (Loss)/Income Attributable to Controlling Interests	**(1,146)**	1,840	1,786
Preferred share dividends	**94**	97	74
Net (Loss)/Income Attributable to Common Shares	**(1,240)**	1,743	1,712
Net (Loss)/Income per Common Share (Note 19)			
Basic and diluted	**($1.75)**	$2.46	$2.42
Dividends Declared per Common Share	**$2.08**	$1.92	$1.84
Weighted Average Number of Common Shares (millions) (Note 19)			
Basic	**709**	708	707
Diluted	**709**	710	708

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	2015	2014	2013
Net (Loss)/Income	**(1,140)**	1,993	1,911
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains on net investment in foreign operations	**813**	517	383
Change in fair value of net investment hedges	**(372)**	(276)	(239)
Change in fair value of cash flow hedges	**(57)**	(69)	71
Reclassification to net income of gains and losses on cash flow hedges	**88**	(55)	41
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**51**	(102)	67
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**32**	18	23
Other comprehensive income/(loss) on equity investments	**47**	(204)	234
Other comprehensive income/(loss) (Note 21)	**602**	(171)	580
Comprehensive (Loss)/Income	**(538)**	1,822	2,491
Comprehensive income attributable to non-controlling interests	**312**	283	191
Comprehensive (Loss)/Income Attributable to Controlling Interests	**(850)**	1,539	2,300
Preferred share dividends	**94**	97	74
Comprehensive (Loss)/Income Attributable to Common Shares	**(944)**	1,442	2,226

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2015	2014	2013
Cash Generated from Operations			
Net (loss)/income	**(1,140)**	1,993	1,911
Depreciation and amortization	**1,765**	1,611	1,485
Asset impairment charges (Note 7)	**3,745**	—	—
Deferred income taxes (Note 15)	**(102)**	686	568
Income from equity investments (Note 8)	**(440)**	(522)	(597)
Distributed earnings received from equity investments (Note 8)	**576**	579	605
Employee post-retirement benefits expense, net of funding (Note 22)	**44**	37	50
Loss/(gain) on assets held for sale/sold (Notes 6 and 25)	**125**	(117)	—
Equity allowance for funds used during construction	**(165)**	(95)	(19)
Unrealized losses/(gains) on financial instruments	**58**	74	(35)
Other	**47**	22	32
Increase in operating working capital (Note 24)	**(398)**	(189)	(326)
Net cash provided by operations	**4,115**	4,079	3,674
Investing Activities			
Capital expenditures (Note 4)	**(3,918)**	(3,489)	(4,264)
Capital projects in development (Note 4)	**(511)**	(848)	(488)
Contributions to equity investments (Note 8)	**(493)**	(256)	(163)
Acquisitions, net of cash acquired (Note 25)	**(236)**	(241)	(216)
Proceeds from sale of assets, net of transaction costs (Note 25)	**—**	196	—
Distributions in excess of equity earnings (Note 8)	**226**	159	128
Deferred amounts and other	**322**	335	(117)
Net cash used in investing activities	**(4,610)**	(4,144)	(5,120)
Financing Activities			
Notes payable (repaid)/issued, net	**(1,382)**	544	(492)
Long-term debt issued, net of issue costs	**5,045**	1,403	4,253
Long-term debt repaid	**(2,105)**	(1,069)	(1,286)
Junior subordinated notes issued, net of issue costs	**917**	—	—
Dividends on common shares	**(1,446)**	(1,345)	(1,285)
Dividends on preferred shares	**(92)**	(94)	(71)
Distributions paid to non-controlling interests	**(224)**	(178)	(166)
Common shares issued	**27**	47	72
Common shares repurchased (Note 19)	**(294)**	—	—
Preferred shares issued, net of issue costs (Note 20)	**243**	440	585
Partnership units of subsidiary issued, net of issue costs	**55**	79	384
Preferred shares of subsidiary redeemed (Note 18)	**—**	(200)	(200)
Net cash provided by/(used in) financing activities	**744**	(373)	1,794
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**112**	—	28
Increase/(Decrease) in Cash and Cash Equivalents	**361**	(438)	376
Cash and Cash Equivalents			
Beginning of year	**489**	927	551
Cash and Cash Equivalents			
End of year	**850**	489	927

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2015	2014
ASSETS			
Current Assets			
Cash and cash equivalents		**850**	489
Accounts receivable		**1,388**	1,313
Inventories		**323**	292
Other (Note 5)		**1,353**	1,019
		3,914	3,113
Plant, Property and Equipment (Note 7)		**44,817**	41,774
Equity Investments (Note 8)		**6,214**	5,598
Regulatory Assets (Note 9)		**1,184**	1,297
Goodwill (Note 10)		**4,812**	4,034
Intangible and Other Assets (Note 11)		**3,191**	2,646
Restricted Investments		**351**	63
		64,483	58,525
LIABILITIES			
Current Liabilities			
Notes payable (Note 12)		**1,218**	2,467
Accounts payable and other (Note 13)		**3,021**	2,892
Accrued interest		**520**	424
Current portion of long-term debt (Note 16)		**2,547**	1,797
		7,306	7,580
Regulatory Liabilities (Note 9)		**1,159**	263
Other Long-Term Liabilities (Note 14)		**1,260**	1,052
Deferred Income Tax Liabilities (Note 15)		**5,144**	4,857
Long-Term Debt (Note 16)		**29,037**	22,960
Junior Subordinated Notes (Note 17)		**2,422**	1,160
		46,328	37,872
EQUITY			
Common shares, no par value (Note 19)		**12,102**	12,202
Issued and outstanding:	December 31, 2015 – 703 million shares December 31, 2014 – 709 million shares		
Preferred shares (Note 20)		**2,499**	2,255
Additional paid-in capital		**7**	370
Retained earnings		**2,769**	5,478
Accumulated other comprehensive loss (Note 21)		**(939)**	(1,235)
Controlling interests		**16,438**	19,070
Non-controlling interests (Note 18)		**1,717**	1,583
		18,155	20,653
		64,483	58,525

Commitments, Contingencies and Guarantees (Note 26)
Corporate Restructuring Costs (Note 27)
Subsequent Events (Note 28)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:



Russell K. Girling
Director

Siim A. Vanaselja
Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2015	2014	2013
Common Shares			
Balance at beginning of year	**12,202**	12,149	12,069
Shares issued on exercise of stock options (Note 19)	**30**	53	80
Shares repurchased (Note 19)	**(130)**	—	—
Balance at end of year	**12,102**	12,202	12,149
Preferred Shares			
Balance at beginning of year	**2,255**	1,813	1,224
Shares issued under public offering, net of issue costs (Note 20)	**244**	442	589
Balance at end of year	**2,499**	2,255	1,813
Additional Paid-In Capital			
Balance at beginning of year	**370**	401	379
Issuance of stock options, net of exercises	**8**	3	(2)
Dilution impact from TC PipeLines, LP units issued	**6**	9	29
Redemption of subsidiary's preferred shares	**—**	(6)	(5)
Impact of common shares repurchased (Note 19)	**(164)**	—	—
Impact of asset drop downs to TC PipeLines, LP (Note 25)	**(213)**	(37)	—
Balance at end of year	**7**	370	401
Retained Earnings			
Balance at beginning of year	**5,478**	5,096	4,687
Net (loss)/income attributable to controlling interests	**(1,146)**	1,840	1,786
Common share dividends	**(1,471)**	(1,360)	(1,301)
Preferred share dividends	**(92)**	(98)	(76)
Balance at end of year	**2,769**	5,478	5,096
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,235)**	(934)	(1,448)
Other comprehensive income/(loss) (Note 21)	**296**	(301)	514
Balance at end of year	**(939)**	(1,235)	(934)
Equity Attributable to Controlling Interests	**16,438**	19,070	18,525
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,583**	1,611	1,425
Net (loss)/income attributable to non-controlling interests			
TC PipeLines, LP	**(13)**	136	93
Portland Natural Gas Transmission System	**19**	15	12
Preferred share dividends of TCPL	**—**	2	20
Other comprehensive income attributable to non-controlling interests	**306**	130	66
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**55**	79	384
Decrease in TransCanada's ownership of TC PipeLines, LP	**(11)**	(14)	(47)
Distributions declared to non-controlling interests	**(222)**	(182)	(166)
Redemption of subsidiary's preferred shares	**—**	(194)	(195)
Other	**—**	—	19
Balance at end of year	**1,717**	1,583	1,611
Total Equity	**18,155**	20,653	20,136

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy infrastructure company which operates in three business segments, Natural Gas Pipelines, Liquids Pipelines and Energy, each of which offers different products and services.

Natural Gas Pipelines

The Natural Gas Pipelines segment consists of the Company's investments in 67,300 km (41,900 miles) of regulated natural gas pipelines and 250 Bcf of regulated natural gas storage facilities. These assets are located in Canada, the United States (U.S.) and Mexico.

Liquids Pipelines

The Liquids Pipelines segment consists of 4,247 km (2,639 miles) of wholly-owned and operated crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Energy

The Energy segment primarily consists of the Company's investments in 19 electrical power generation plants and 2 non-regulated natural gas storage facilities. These include Canadian plants in Alberta, Ontario, Québec and New Brunswick and U.S. plants in New York, New England and Arizona.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-controlling interests. TransCanada uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TransCanada records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

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 judgment in making these estimates and assumptions. Significant estimates and judgments used in the preparation of the consolidated financial statements include, but are not limited to:

- fair value and depreciation rates of plant, property and equipment (Note 7);
- carrying value of regulatory assets and liabilities (Note 9);
- fair value of goodwill (Note 10);
- amortization rates and fair value of intangible assets (Note 11);
- carrying value of asset retirement obligations (Note 14);
- provisions for income taxes (Note 15);
- assumptions used to measure retirement and other post-retirement obligations (Note 22);
- fair value of financial instruments (Note 23); and
- provision for commitments, contingencies and guarantees (Note 26).

Actual results could differ from those estimates.

Regulation

In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB). In the U.S., natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). The Company's Canadian, U.S. and Mexican natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TransCanada's rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain of its liquids pipelines projects. RRA is not applicable to the Keystone Pipeline System as the regulators' decisions regarding operations and tolls on that system generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas Pipelines and Liquids Pipelines

Revenues from the Company's natural gas and liquids pipelines, with the exception of Canadian natural gas pipelines which are subject to RRA, are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made.

Revenues from Canadian natural gas pipelines subject to RRA are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include a return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are at times subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to recover the costs that are subject to incentives. Revenues are recognized on firm contracted capacity ratably over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved ROE assumptions. Adjustments to revenue are recorded when the NEB decision is received.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final.

Revenues from the Company's regulated natural gas storage services are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored and when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the gas or oil that it transports or stores for others.

Energy

Power

Revenues from the Company's Energy business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative Instruments and Hedging Activities section of this note.

Natural Gas Storage

Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Derivative contracts for the purchase or sale of natural gas are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates, reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in plant, property and equipment and the equity component of AFUDC is a non-cash expenditure with a corresponding credit recognized in Interest income and other expense in the Consolidated statement of income. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Liquids Pipelines

Plant, property and equipment for liquids pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of these assets includes interest capitalized during construction for non-regulated liquids pipelines and AFUDC for regulated pipelines. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy

Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Corporate

Corporate Plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Capitalized Project Costs

The Company capitalizes project costs once advancement to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest for non-regulated projects in development and AFUDC for regulated projects. Capital projects in development are included in Intangible and other assets. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to Plant, property and equipment under construction. When the asset is ready for its intended use and available for operations, capitalized project costs are depreciated in accordance with the Company's depreciation policies.

Project costs related to acquisitions are capitalized once the acquisition is probable.

Assets Held For Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next twelve months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, reduced for selling costs, and any losses are recognized in income. Depreciation expense is no longer recorded for any assets that are classified as held for sale.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as Plant, property and equipment and Intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows or the estimated price to sell is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the fair value of the asset.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that the asset might be impaired. The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company initially assesses qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. If TransCanada concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its carrying value, which includes goodwill. If the fair value is less than carrying value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference.

Power Purchase Arrangements

A power purchase agreement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. Substantially all PPAs under which TransCanada buys power are accounted for as operating leases. Initial payments for these PPAs were recognized in Intangible and other assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. A portion of these PPAs has been subleased to third parties under terms and conditions similar to the PPAs. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the NEB's Land Matters Consultation Initiative (LMCI), TransCanada is required to collect funds to cover estimated future pipeline abandonment costs for all NEB regulated Canadian pipelines. Collected funds are placed in trusts that hold and invest the funds and are accounted for as Restricted investments. LMCI restricted investments may only be used to abandon the NEB regulated pipeline facilities; therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, NGTL System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

The Company has recorded ARO related to the non-regulated natural gas storage operations and certain power generation facilities. The scope and timing of asset retirements related to natural gas pipelines, liquids pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and expensed when they are utilized. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Consolidated balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period, with an offset to Additional paid-in capital. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service life of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income/(loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income/(loss) (AOCI) over the average remaining service life of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the company or reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt has been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify and are designated for hedge accounting treatment, which includes fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other expense and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net income. The amounts recognized previously in AOCI are reclassified to Net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in Net income in the period of change.

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 through the tolls charged by the Company. 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.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in Net income.

Long-Term Debt Transaction Costs

The Company records Long-term debt transaction costs as other assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments, Plant, property and equipment, or a charge to Net income, and a corresponding liability is recorded in Other long-term liabilities.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2015

Derivatives and Hedging

In August 2015, the Financial Accounting Standards Board (FASB) issued new guidance on the application of the normal purchases and normal sales scope exception to certain electricity contracts within nodal energy markets. The amendments in this update apply to entities that enter into contracts for the purchase or sale of electricity on a forward basis and arrange for transmission through or delivery to a location within a nodal energy market whereby one of the contracting parties incurs charges (or credits) for the transmission of that electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. This new guidance was effective upon issuance, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued new guidance which requires that deferred tax assets and liabilities be classified as non-current on the balance sheet. The new guidance is effective January 1, 2017, however, since early application is permitted, the Company elected to retrospectively apply this guidance effective January 1, 2015. Application of this new guidance will simplify the Company’s process in determining deferred tax amounts and simplify their presentation. The application of this amendment resulted in a reclassification of Deferred tax assets previously recorded in Other current assets, and Deferred tax liabilities previously recorded in Accounts payable and other to non-current Deferred income tax assets and liabilities. Prior year amounts have been reclassified to conform to current year presentation.

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 was applied prospectively from January 1, 2015 and there was no impact on the Company's consolidated financial statements as a result of applying this new standard.

Future Accounting Changes

Revenue from contracts with customers

In 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. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are 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.

The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Extraordinary and unusual income statement items

In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from GAAP the concept of extraordinary items. This new guidance is effective from January 1, 2016 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.

Consolidation

In February 2015, the FASB issued new guidance on consolidation analysis. This update requires that entities reevaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance is effective from January 1, 2016 and will be applied retrospectively. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance is effective January 1, 2016 and will be applied retrospectively. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in Intangible and other assets to an offset of their respective debt liabilities.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 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.

Business Combinations

In September 2015, the FASB issued guidance which replaces the requirement that an acquirer in a business combination account for measurement period adjustments retrospectively with a requirement that an acquirer recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amended guidance requires that the acquirer record, in the same period's financial statements as the adjustment was determined, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The new guidance is effective January 1, 2016 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.

4. SEGMENTED INFORMATION

year ended December 31, 2015 (millions of Canadian $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	**5,383**	**1,879**	**4,038**	**—**	**11,300**
Income from equity investments	**179**	**—**	**261**	**—**	**440**
Plant operating costs and other	**(1,736)**	**(478)**	**(766)**	**(270)**	**(3,250)**
Commodity purchases resold	**—**	**—**	**(2,237)**	**—**	**(2,237)**
Property taxes	**(349)**	**(79)**	**(89)**	**—**	**(517)**
Depreciation and amortization	**(1,132)**	**(266)**	**(336)**	**(31)**	**(1,765)**
Asset impairment charges	**—**	**(3,686)**	**(59)**	**—**	**(3,745)**
Loss on assets held for sale	**(125)**	**—**	**—**	**—**	**(125)**
Segmented earnings/(losses)	**2,220**	**(2,630)**	**812**	**(301)**	**101**
Interest expense					**(1,370)**
Interest income and other					**163**
Loss before income taxes					**(1,106)**
Income tax expense					**(34)**
Net loss					**(1,140)**
Net income attributable to non-controlling interests					**(6)**
Net loss attributable to controlling interests					**(1,146)**
Preferred share dividends					**(94)**
Net loss attributable to common shares					**(1,240)**
Capital spending					
Capital expenditures	**2,466**	**1,012**	**376**	**64**	**3,918**
Capital projects in development	**233**	**278**	**—**	**—**	**511**
	2,699	**1,290**	**376**	**64**	**4,429**

year ended December 31, 2014 (millions of Canadian $)	**Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,913	1,547	3,725	—	10,185
Income from equity investments	163	—	359	—	522
Plant operating costs and other	(1,501)	(426)	(919)	(127)	(2,973)
Commodity purchases resold	—	—	(1,836)	—	(1,836)
Property taxes	(334)	(62)	(77)	—	(473)
Depreciation and amortization	(1,063)	(216)	(309)	(23)	(1,611)
Gain on assets sold	9	—	108	—	117
Segmented earnings/(losses)	2,187	843	1,051	(150)	3,931
Interest expense					(1,198)
Interest income and other					91
Income before income taxes					2,824
Income tax expense					(831)
Net income					1,993
Net income attributable to non-controlling interests					(153)
Net income attributable to controlling interests					1,840
Preferred share dividends					(97)
Net income attributable to common shares					1,743
Capital spending					
Capital expenditures	1,768	1,469	206	46	3,489
Capital projects in development	368	480	—	—	848
	2,136	1,949	206	46	4,337

year ended December 31, 2013 (millions of Canadian $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,497	1,124	3,176	—	8,797
Income from equity investments	145	—	452	—	597
Plant operating costs and other	(1,405)	(328)	(833)	(108)	(2,674)
Commodity purchases resold	—	—	(1,317)	—	(1,317)
Property taxes	(329)	(44)	(72)	—	(445)
Depreciation and amortization	(1,027)	(149)	(293)	(16)	(1,485)
Segmented earnings/(losses)	1,881	603	1,113	(124)	3,473
Interest expense					(985)
Interest income and other					34
Income before income taxes					2,522
Income tax expense					(611)
Net income					1,911
Net income attributable to non-controlling interests					(125)
Net income attributable to controlling interests					1,786
Preferred share dividends					(74)
Net income attributable to common shares					1,712
Capital spending					
Capital expenditures	1,776	2,286	152	50	4,264
Capital projects in development	245	243	—	—	488
	2,021	2,529	152	50	4,752

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

Geographic Information

year ended December 31 (millions of Canadian $)	2015	2014	2013
Revenues			
Canada – domestic	**3,877**	3,956	4,659
Canada – export	**1,292**	1,314	997
United States	**5,872**	4,718	3,029
Mexico	**259**	197	112
	11,300	10,185	8,797

at December 31 (millions of Canadian $)	2015	2014
Plant, Property and Equipment		
Canada	**19,287**	19,191
United States	**21,899**	20,098
Mexico	**3,631**	2,485
	44,817	41,774

5. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2015	2014
Cash held as collateral	**585**	423
Fair value of derivative contracts (Note 23)	**442**	409
Regulatory assets (Note 9)	**85**	16
Assets held for sale (Note 6)	**20**	—
Other	**221**	171
	1,353	1,019

6. ASSETS HELD FOR SALE

On December 18, 2015, the Company entered into an agreement to sell TC Offshore LLC (TCO) to a third party and expects the sale to close in early 2016. As a result, at December 31, 2015, the related assets and liabilities were held for sale in the Natural Gas Pipelines segment and were recorded at their fair values less costs to sell. This resulted in a loss of $125 million pre-tax in 2015 which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. TCO is a FERC regulated entity that operates as part of ANR. TCO does not represent a major line of business or geographical area of the Company, and therefore is not considered to be a discontinued operation as of December 31, 2015.

at December 31 (millions of Canadian $)	2015
Assets Held for Sale	
Accounts receivable	**4**
Inventories	**1**
Other current assets	**1**
Plant, property and equipment	**14**
Total Assets Held for Sale (included in Other current assets, Note 5)	**20**
Liabilities Related to Assets Held for Sale	
Accounts payable and other	**38**
Other long-term liabilities	**1**
Total Liabilities Related to Assets Held for Sale (included in Accounts payable and other, Note 13)	**39**

7. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2015 Cost	2015 Accumulated Depreciation	2015 Net Book Value	2014 Cost	2014 Accumulated Depreciation	2014 Net Book Value
Natural Gas Pipelines						
Canadian Mainline						
Pipeline	**9,164**	**5,966**	**3,198**	9,045	5,712	3,333
Compression	**3,433**	**2,220**	**1,213**	3,423	2,100	1,323
Metering and other	**499**	**192**	**307**	458	180	278
	13,096	**8,378**	**4,718**	12,926	7,992	4,934
Under construction	**257**	**—**	**257**	135	—	135
	13,353	**8,378**	**4,975**	13,061	7,992	5,069
NGTL System						
Pipeline	**8,456**	**3,820**	**4,636**	8,185	3,619	4,566
Compression	**2,188**	**1,404**	**784**	2,055	1,318	737
Metering and other	**1,096**	**489**	**607**	1,032	446	586
	11,740	**5,713**	**6,027**	11,272	5,383	5,889
Under construction	**969**	**—**	**969**	413	—	413
	12,709	**5,713**	**6,996**	11,685	5,383	6,302
ANR[1]						
Pipeline	**1,449**	**350**	**1,099**	1,217	227	990
Compression	**1,101**	**187**	**914**	780	140	640
Metering and other	**977**	**252**	**725**	737	231	506
	3,527	**789**	**2,738**	2,734	598	2,136
Under construction	**304**	**—**	**304**	127	—	127
	3,831	**789**	**3,042**	2,861	598	2,263
Mexico						
Pipeline	**1,296**	**162**	**1,134**	1,053	104	949
Compression	**183**	**14**	**169**	151	6	145
Metering and other	**388**	**27**	**361**	314	20	294
	1,867	**203**	**1,664**	1,518	130	1,388
Under construction	**1,959**	**—**	**1,959**	1,098	—	1,098
	3,826	**203**	**3,623**	2,616	130	2,486
Other Natural Gas Pipelines						
GTN	**2,278**	**765**	**1,513**	1,842	588	1,254
Great Lakes	**2,157**	**1,155**	**1,002**	1,807	939	868
Foothills	**1,606**	**1,162**	**444**	1,671	1,180	491
Other[2]	**2,223**	**572**	**1,651**	1,800	363	1,437
	8,264	**3,654**	**4,610**	7,120	3,070	4,050
Under construction	**71**	**—**	**71**	34	—	34
	8,335	**3,654**	**4,681**	7,154	3,070	4,084
	42,054	**18,737**	**23,317**	37,377	17,173	20,204

Liquids Pipelines						
Keystone						
Pipeline	**9,288**	**718**	**8,570**	7,931	463	7,468
Pumping equipment	**1,092**	**108**	**984**	964	80	884
Tanks and other	**3,034**	**228**	**2,806**	2,282	144	2,138
	13,414	**1,054**	**12,360**	11,177	687	10,490
Under construction	**1,826**	**—**	**1,826**	4,438	—	4,438
	15,240	**1,054**	**14,186**	15,615	687	14,928
Energy						
Natural Gas – Ravenswood	**2,607**	**654**	**1,953**	2,140	476	1,664
Natural Gas – Other[3,4]	**3,361**	**1,164**	**2,197**	3,214	971	2,243
Hydro, Wind and Solar[5]	**2,417**	**476**	**1,941**	2,194	359	1,835
Natural Gas Storage and Other	**740**	**132**	**608**	717	118	599
	9,125	**2,426**	**6,699**	8,265	1,924	6,341
Under construction	**430**	**—**	**430**	149	—	149
	9,555	**2,426**	**7,129**	8,414	1,924	6,490
Corporate	**267**	**82**	**185**	232	80	152
	67,116	**22,299**	**44,817**	61,638	19,864	41,774

1 TCO is excluded from the ANR net book value at December 31, 2015 as it has been classified as an asset held for sale. Refer to Note 6 for further information.
2 Includes Bison, Portland Natural Gas Transmission System (PNGTS), North Baja, Tuscarora and Ventures LP.
3 Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $ 813 million and $142 million, respectively, at December 31, 2015 (2014 – $695 million and $103 million, respectively). Revenues of $ 93 million were recognized in 2015 (2014 – $81 million; 2013 – $78 million) through the sale of electricity under the related PPAs.
4 Includes Halton Hills, Coolidge, Bécancour, Ocean State Power, Mackay River and other natural gas-fired facilities.
5 Includes the acquisitions of four solar power facilities in 2014.

Keystone XL Impairment

At December 31, 2015, the Company evaluated its investment in Keystone XL and related projects, including the Keystone Hardisty Terminal (KHT), for impairment in connection with the November 6, 2015 denial of the U.S. Presidential permit. As a result of the analysis, the Company recognized a non-cash impairment charge of $3,686 million ($2,891 million after-tax) based on the excess of the carrying value over the estimated fair value of$621 million of these assets. The impairment charge includes $77 million ($56 million after-tax) for certain cancellation fees that will be incurred in the future if the project is ultimately abandoned.

at December 31, 2015	**Estimated**	**Impairment charge**	
(millions of Canadian $)	**Fair Value**	**Pre-tax**	**After-tax**
Plant and equipment	**463**	**1,460**	**1,391**
Terminals, including KHT	**158**	**274**	**219**
Intangible assets	**—**	**1,150**	**737**
Capitalized interest	**—**	**725**	**488**
Future cancellation costs	**—**	**77**	**56**
	621	**3,686**	**2,891**

The estimated fair value of $463 million related to plant and equipment was based on the price that would be received on sale of the plant and equipment in its current condition. An independent third party valuation was utilized in the assessment of the fair value of these assets. Key assumptions used in the determination of selling price included an estimated two year disposal period and the current weak energy market conditions. The valuation considered a variety of potential selling prices that were based on the various markets that could be used in order to dispose of these assets.

The estimated $158 million fair value of the terminal assets, including KHT, was determined using a discounted cash flow approach as a measure of fair value. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value.

The valuation techniques above required the use of unobservable inputs. As a result, the fair value is classified within Level 3 of the fair value hierarchy. Refer to Note 23 for further information on the fair value hierarchy.

Energy Turbine Impairment

Following the evaluation of specific capital project opportunities in 2015, it was determined that the carrying value of certain Energy turbine equipment was not fully recoverable. These turbines had been previously purchased for a power development project that did not proceed. As a result, at December 31, 2015, the Company recognized a non-cash impairment charge of $59 million ($43 million after-tax). This impairment charge was based on the excess of the carrying value over the fair value of the turbines, which was determined based on a comparison to similar assets available for sale in the market.

8. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2015	Income / (Loss) from Equity Investments year ended December 31 2015	2014	2013	Equity Investments at December 31 2015	2014
Natural Gas Pipelines						
Northern Border[1,2]		**85**	76	66	**664**	587
Iroquois	44.5%	**51**	43	41	**238**	210
TQM	50.0%	**12**	12	13	**72**	73
Other	Various	**31**	32	25	**73**	68
Liquids Pipelines						
Grand Rapids	50.0%	**—**	—	—	**542**	240
Canaport Energy East Marine Terminal	50.0%	**—**	—	—	**16**	—
Energy						
Bruce Power[3,4]	48.5%	**249**	314	310	**4,200**	3,995
ASTC Power Partnership	50.0%	**(23)**	8	110	**21**	29
Portlands Energy	50.0%	**30**	36	31	**321**	335
Other	Various	**5**	1	1	**67**	61
		440	522	597	**6,214**	5,598

1 The results reflect a 50.0 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2015, TransCanada had an ownership interest in TC PipeLines, LP of 28.0 per cent (2014 – 28.3 and 2013 – 28.9 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 14.0 per cent (2014 – 14.2 and 2013 – 14.5 per cent).

2 At December 31, 2015, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$117 million (2014 – US$117 million) due to the fair value assessment of assets at the time of acquisition.

3 As a result of TransCanada's increased ownership in Bruce Power L.P. (Bruce B) and the merger of Bruce Power A L.P. (Bruce A) and Bruce B (to form Bruce Power) in December 2015, TransCanada has an ownership interest in Bruce Power of 48.5 per cent. Prior to the acquisition and merger, TransCanada applied equity accounting to its 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. TransCanada continues to apply equity accounting to Bruce Power. Refer to Note 25 for further information.

4 At December 31, 2015, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $973 million (2014 – $776 million) due to the fair value assessment of assets at the time of acquisitions.

Distributions received from equity investments for the year ended December 31, 2015 were $802 million (2014 – $738 million; 2013 – $733 million) of which $226 million (2014 – $159 million; 2013 – $128 million) were returns of capital and are included in Investing activities in the Consolidated statement of cash flows. The undistributed earnings from equity investments as at December 31, 2015 were $198 million (2014 – $551 million; 2013 – $754 million).

Contributions made to equity investments for the year ended December 31, 2015 were $493 million (2014 – $256 million; 2013 –$163 million) and are included in Equity investments in the Consolidated statement of cash flows.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2015	2014	2013
Income			
Revenues	**4,337**	4,814	4,989
Operating and other expenses	**(3,254)**	(3,489)	(3,536)
Net income	**1,046**	1,264	1,390
Net income attributable to TransCanada	**440**	522	597

at December 31 (millions of Canadian $)	2015	2014
Balance Sheet		
Current assets	**1,530**	1,412
Non-current assets	**13,190**	12,260
Current liabilities	**(1,370)**	(1,067)
Non-current liabilities	**(3,116)**	(3,255)

9. RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain Canadian liquids pipelines currently in development. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

The Canadian Mainline, NGTL System, Foothills and TQM pipelines are regulated by the NEB under the*National Energy Board Act*. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

TransCanada's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur.

Canadian Mainline

In March 2015, TransCanada filed a compliance filing with the NEB in response to the RH-001-2014 Decision on TransCanada's 2015-2030 Tolls Application (the NEB 2014 Decision) and is required to file a toll review for the 2018 to 2020 period prior to December 31, 2017. In June 2015, the NEB approved the applied-for compliance tolls as filed and these tolls became effective on July 1, 2015.

The NEB's 2014 Decision acknowledged that an off-ramp had been reached on the NEB 2013 Decision (described below) and approved fixed tolls for 2015 to 2020 as well as certain parameters for a toll setting methodology to 2030. Features of the settlement reached with shippers as approved in the NEB 2014 Decision include an ROE of 10.1 per cent on deemed common equity of40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TransCanada contribution to reduce the revenue requirement. Toll stabilization is achieved through the continued use of deferral accounts, namely the Long-term adjustment account (LTAA) and the Bridging amortization account, to capture the surplus or the

shortfall between the Company's revenues and cost of service for each year over the six-year fixed toll term of the NEB 2014 Decision.

In March 2013, the Company received a decision from the NEB which set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others (the NEB 2013 Decision). The decision established an ROE of 11.5 per cent on deemed common equity of 40 per cent and included mechanisms to achieve the fixed tolls through the use of a LTAA as well as the establishment of a Tolls Stabilization Account (TSA) to capture the surplus or the shortfall between revenues and cost of service for each year over the five-year term of the decision. In addition, the decision provided an opportunity to generate incentive earnings by increasing revenues and reducing costs. The NEB also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances occurred in 2013 when the TSA balance became positive. In December 2013, TransCanada filed the 2015-2030 Tolls Application with the NEB that addressed tolls moving forward including continuation of the NEB 2013 Decision tolls for 2014.

NGTL System

In February 2015, the NEB approved the NGTL System's 2015 Revenue Requirement Settlement. The terms of the one year settlement include ROE 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 annual operating, maintenance and administration (OM&A) cost amount that was based on an escalation of 2014 actual costs.

The NGTL System's 2014 results reflect the terms of the 2013-2014 Revenue Requirement Settlement Application. This settlement had fixed annual OM&A costs and a 10.1 per cent ROE on deemed common equity of 40 per cent. Any variance between fixed OM&A costs in the settlement and actual costs accrued to TransCanada. The settlement also included a composite depreciation rate of 3.12 per cent in 2014.

Energy East

Energy East is currently in the development stage, awaiting regulatory approval from the NEB. Tolls will be designed to provide for cost recovery including return of and on capital as approved by the NEB.

Other Canadian Pipelines

The Foothills operating model for 2014 and 2015 provides for recovery of all revenue requirement components on a flow-through basis. TQM operates under a model consisting of fixed and flow-through revenue requirement components for 2014 through 2016. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations

TransCanada's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (NGA) and the Energy Policy Act of 2005, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR

ANR's natural gas transportation and storage services are provided under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective for all periods presented, beginning in 1997. On January 29, 2016, ANR Pipeline Company filed an application with the FERC under section 4 of the NGA to establish new rates expected to be effective, subject to refund, on August 1, 2016.

ANR Storage Company rates were established pursuant to a settlement approved by the FERC in August 2012 and ANR Storage Company is required to file for new rates to be effective no later than July 1, 2016.

TCO, another ANR-related regulated entity, began operating under FERC-approved tariff rates on November 1, 2012. As at December 31, 2015, TCO assets were classified as Assets held for sale. Refer to Note 6 for more information.

Other U.S. Natural Gas Pipelines

GTN, Great Lakes and Bison are regulated by the FERC and operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. Each pipeline is permitted to discount or negotiate these rates on a non-discriminatory basis.

GTN's rates were established pursuant to a settlement approved by the FERC in January 2012. On June 30, 2015, FERC approved GTN's new settlement with its shippers which satisfies GTN's obligations from the 2012 settlement for new rates to be in effect on January 1, 2016, and reduced rates on the mainline by three per cent on July 1, 2015. In January 2016, GTN's rates will decrease a further10 percent and will continue in effect through December 31, 2019. Unless superseded by a subsequent rate case or settlement, GTN's rates will decrease an additional eight per cent for the period January 1, 2020 through December 31, 2021 when GTN will be required to establish new rates.

Great Lakes operates under rates established pursuant to a settlement approved by the FERC in November 2013. Under the settlement, Great Lakes is required to file for new rates to be effective no later than January 1, 2018.

Bison continues to operate under the rates approved by FERC in connection with Bison's initial construction and has no requirement to file a new rate proceeding.

Mexico Regulated Operations

TransCanada's Mexican operations are regulated by the CRE and operate in accordance with CRE-approved tariffs. In 2014, TransCanada began using RRA for all natural gas pipelines in Mexico. The rates were established based on CRE approved negotiated contracts.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2015	2014	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**848**	1,001	n/a
Operating and debt-service regulatory assets[2]	**47**	4	1
Pensions and other post retirement benefits[3]	**210**	236	n/a
Foreign exchange on long-term debt[5]	**54**	—	1-14
Other[4]	**110**	72	n/a
	1,269	1,313	
Less: Current portion included in Other current assets (Note 5)	**85**	16	
	1,184	1,297	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**—**	42	1-14
Operating and debt-service regulatory liabilities[2]	**32**	21	1
ANR-related post-employment and retirement benefits other than pension[6]	**147**	117	n/a
Long term adjustment account[7]	**231**	64	45
Pipeline abandonment costs[8]	**285**	—	n/a
Bridging amortization account[9]	**456**	—	15
Other[4]	**52**	49	n/a
	1,203	293	
Less: Current portion included in Accounts payable and other (Note 13)	**44**	30	
	1,159	263	

1 These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2015 would have been $32 million lower (2014 – $28 million higher; 2013 – $76 million lower) had these amounts not been recorded as Regulatory assets and liabilities.

3 These balances represent the regulatory offset to pension plan and other post-retirement obligations to the extent the amounts are expected to be collected from customers in future rates. The balances are excluded from the rate base and do not earn a return on investment. Pre-tax operating results in 2015 would have been $26 million higher (2014 – $46 million lower; 2013 – $171 million higher) had these amounts not been recorded as regulatory assets and liabilities.

4 Pre-tax operating results in 2015 would have been $35 million lower (2014 – $2 million higher; 2013 – $2 million higher) had these amounts not been recorded as regulatory assets and liabilities.

5 Foreign exchange on long-term debt of the NGTL System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, GAAP would have required the inclusion of these unrealized gains or losses in Net income.

6 Under the terms of ANR's last rate settlement, ANR will be required to make refunds to its customers, pursuant to a refund plan to be approved by FERC in a future rate proceeding, of those amounts in the post-retirement benefit trust fund that have not been used to pay benefits to its employees. This regulatory liability represents the difference between the amount collected in rates and the amount of post-retirement benefits expense. ANR anticipates that the resolution of this liability will be determined through the section 4 rate case ANR filed with the FERC on January 29, 2016. Since the timing of the rate case conclusion is uncertain, a settlement period cannot be determined at this time. Pre-tax operating results in 2015 would have been $30 million higher (2014 – $13 million higher; 2013 – $16 million higher) had these amounts not been recorded as regulatory assets and liabilities.

7 Pre-tax operating results in 2015 would have been $ 167 million higher (2014 – $418 million higher; 2013 – $247 million lower) had these amounts not been recorded as regulatory liabilities.

8 Effective January 1, 2015, NEB regulated pipelines including the Mainline, NGTL System, Foothills, Keystone and TQM are required to collect and set-aside funds received from customers to be used for future pipeline abandonment activities. Funds are collected through a surcharge mechanism, set-aside in trust accounts, and the obligation to use these funds for future pipeline abandonment activities is recorded as a regulatory liability. Pre-tax operating results in 2015 would have been $285 million higher (2014 – nil; 2013 – nil) had these amounts not been recorded as regulatory liabilities.

9 Pre-tax operating results in 2015 would have been $ 456 million higher (2014 – nil; 2013 – nil) had these amounts not been recorded as regulatory liabilities.

Allowance for Funds Used During Construction

The total amount of debt and equity AFUDC included in the Consolidated statement of income was $295 million in 2015 (2014 – $136 million; 2013 – $37 million).

10. GOODWILL

The Company has recorded the following Goodwill on its acquisitions in the U.S.:

(millions of Canadian $)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2014	2,816	880	3,696
Foreign exchange rate changes	258	80	338
Balance at December 31, 2014	3,074	960	4,034
Foreign exchange rate changes	**593**	**185**	**778**
Balance at December 31, 2015	**3,667**	**1,145**	**4,812**

At December 31, 2015, TransCanada's Goodwill included US$573 million (2014 - US$573 million) related to the Great Lakes natural gas transportation business. TransCanada's share of this Goodwill (net of non-controlling interests) was US$386 million (2014 – US$243 million). The increase in TransCanada's share is a result of the impairment charge of US$199 million recorded by TC PipeLines, LP on its equity method goodwill related to Great Lakes. On a consolidated basis, TransCanada's carrying value of its investment in Great Lakes is proportionately lower compared to the 46.45% owned through TC PipeLines, LP. As a result, the estimated fair value of Great Lakes exceeded TransCanada's consolidated carrying value of the investment and no impairment was recorded in 2015.

The estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured by using a discounted cash flow analysis. Assumptions regarding Great Lakes' ability to realize long-term value in the North American energy market have been adversely impacted by the changing natural gas flows in its market region as well as a change in the Company's view of other strategic alternatives to increase utilization of Great Lakes. As a result, the Company reduced forecasted cash flows from the reporting unit for the next ten years as compared to those utilized in previous impairment tests. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the Goodwill balance relating to Great Lakes.

11. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2015	2014
Capital projects in development	**1,814**	1,286
PPAs	**220**	272
Fair value of derivative contracts (Note 23)	**168**	93
Loans and advances[1]	**159**	167
Employee post-retirement benefits (Note 22)	**18**	14
Deferred income tax assets and charges (Note 15)	**15**	185
Other	**797**	629
	3,191	2,646

1 TransCanada held a note receivable from the seller of Ravenswood of $ 213 million (US$154 million) and $213 million (US$184 million) as at December 31, 2015 and at December 31, 2014 , which bears interest at 6.75 per cent and matures in 2040. The current portion included in Other current assets was $ 55 million (US$40 million) at December 31, 2015 and $46 million (US$40 million) at December 31, 2014.

The following amounts related to PPAs are included in Intangible and other assets:

at December 31 (millions of Canadian $)	2015 Cost	2015 Accumulated Amortization	2015 Net Book Value	2014 Cost	2014 Accumulated Amortization	2014 Net Book Value
Sheerness (expires 2020)	**585**	**390**	**195**	585	351	234
Sundance A (expires 2017)	**225**	**200**	**25**	225	187	38
	810	**590**	**220**	810	538	272

Amortization expense for these PPAs was $52 million for the year ended December 31, 2015 (2014 and 2013 – $52 million). The expected annual amortization expense for 2016 and 2017 is $52 million, and $39 million for 2018 to 2020.

12. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2015 Outstanding at December 31	2015 Weighted Average Interest Rate per Annum at December 31	2014 Outstanding at December 31	2014 Weighted Average Interest Rate per Annum at December 31
Canadian	**697**	**0.8%**	1,540	1.2%
U.S. (2015 – US$376; 2014 – US$800)	**521**	**1.1%**	927	0.7%
	1,218		2,467	

At December 31, 2015, Notes payable consists of commercial paper issued by TransCanada PipeLines Limited (TCPL), TransCanada American Investments Ltd. (TAIL), and TransCanada Power Marketing Ltd. (TCPM). In November 2015, the TAIL credit facility was increased to US$1.5 billion from US$1.0 billion and, subsequently, TAIL and TCPM became co-borrowers under the facility and co-issuers under the related commercial paper program. At the same time, the TCPL USA credit facility was reduced from the US$1.0 billion to US$0.5 billion. In December 2015, a new US$1.0 billion credit facility and related commercial paper program was initiated for TCPL.

At December 31, 2015, total committed revolving and demand credit facilities of $8.9 billion (2014 – $6.7 billion) were available. When drawn, interest on these lines of credit is charged at prime rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31, 2015					year ended December 31 2015	2014	2013
Amount	**Unused Capacity**	**Borrower**	**Description**	**Matures**	**Cost to maintain** (millions of Canadian $)		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2020	**6**	6	4
US$1 billion	US$1 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2016	**—**	—	—
US$0.5 billion	US$0.5 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL	December 2016	**3**	2	1
US$1.5 billion	US$1.5 billion	TAIL/TCPM	Committed, syndicated, revolving, extendible TAIL/TCPM credit facility, guaranteed by TCPL	December 2016	**2**	1	—
$1.7 billion	$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand	**—**	—	—

At December 31, 2015, the Company's operated affiliates had an additional $0.6 billion (2014 – $0.4 billion) of undrawn capacity on committed credit facilities.

13. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2015	2014
Trade payables	**1,506**	1,624
Fair value of derivative contracts (Note 23)	**926**	749
Dividends payable	**385**	359
Regulatory liabilities (Note 9)	**44**	30
Liabilities related to assets held for sale (Note 6)	**39**	—
Other	**121**	130
	3,021	2,892

14. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2015	2014
Fair value of derivative contracts (Note 23)	**625**	411
Employee post-retirement benefits (Note 22)	**380**	444
Asset retirement obligations	**109**	98
Guarantees (Note 26)	**26**	20
Other	**120**	79
	1,260	1,052

15. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2015	2014	2013
Current			
Canada	**44**	103	27
Foreign	**92**	42	16
	136	145	43
Deferred			
Canada	**33**	309	245
Foreign	**(135)**	377	323
	(102)	686	568
Income Tax Expense	**34**	831	611

Geographic Components of Income

year ended December 31 (millions of Canadian $)	2015	2014	2013
Canada	**(624)**	1,146	1,224
Foreign	**(482)**	1,678	1,298
(Loss)/Income Before Income Taxes	**(1,106)**	2,824	2,522

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2015	2014	2013
(Loss)/Income before income taxes	**(1,106)**	2,824	2,522
Federal and provincial statutory tax rate	**26.0%**	25.0%	25.0%
Expected income tax (recovery)/expense	**(288)**	706	631
Income tax differential related to regulated operations	**159**	129	(13)
Higher effective foreign tax rates	**14**	25	33
Income from equity investments and non-controlling interests	**(56)**	(38)	(28)
Tax rate and legislative changes	**34**	—	(25)
Asset impairment charges[1]	**170**	—	—
Other	**1**	9	13
Actual Income Tax Expense	**34**	831	611

1 The asset impairment impact is net of $311 million attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2015	2014
Deferred Income Tax Assets		
Difference in accounting and tax bases of impaired assets	**916**	—
Tax loss and credit carryforwards	**1,327**	1,344
Regulatory and other deferred amounts	**231**	236
Unrealized foreign exchange losses on long-term debt	**589**	140
Financial instruments	**111**	104
Other	**136**	149
	3,310	1,973
Less: Valuation allowance[1]	**1,060**	125
	2,250	1,848
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,441**	5,548
Equity investments	**656**	648
Taxes on future revenue requirement	**227**	253
Other	**55**	71
	7,379	6,520
Net Deferred Income Tax Liabilities	**5,129**	4,672

1 In 2015, an increase to the valuation allowance of $ 935 million was recorded as the Company believes that it is more likely than not that the tax benefits related to the unrealized foreign exchange losses on long-term debt and unrealized losses on certain impaired assets will not be realized in the future.

The above deferred tax amounts have been classified in the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2015	2014[1]
Deferred Income Tax Assets		
Intangible and other assets (Note 11)	**15**	185
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**5,144**	4,857
Net Deferred Income Tax Liabilities	**5,129**	4,672

1 As a result of retrospectively applying guidance on the presentation of deferred taxes on the Consolidated balance sheet on January 1, 2015, the Company reclassified its December 31, 2014 current Deferred income tax assets of $427 million, and current Deferred income tax liabilities of $4 million to its non-current Deferred income tax assets and liabilities.

At December 31, 2015, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,283 million (2014 – $1,131 million) for federal and provincial purposes in Canada, which expire from 2026 to 2035. The Company also has Ontario minimum tax credits of $57 million (2014 – $50 million), which expire from 2016 to 2035.

At December 31, 2015, the Company has recognized the benefit of unused net operating loss carryforwards of US$1,617 million (2014 – US$2,267 million) for federal purposes in the U.S., which expire from 2029 to 2034. The Company also has alternative minimum tax credits of US$41 million (2014 – US$26 million).

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2015 by approximately $308 million (2014 – $236 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $162 million, net of refunds, were made in2015 (2014 – payments, net of refunds, of $109 million; 2013 – payments, net of refunds, of $202 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	2015	2014	2013
Unrecognized tax benefit at beginning of year	**18**	23	49
Gross increases – tax positions in prior years	**2**	3	3
Gross decreases – tax positions in prior years	**(2)**	(8)	(28)
Gross increases – tax positions in current year	**1**	1	2
Lapses of statute of limitations	**(2)**	(1)	(3)
Unrecognized Tax Benefit at End of Year	**17**	18	23

TransCanada recognized a favourable income tax adjustment of approximately $25 million due to the enactment of certain Canadian federal tax legislation in June 2013.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TransCanada and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian

federal and provincial income tax matters for the years through 2007. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2010.

TransCanada's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2015 reflects a $1 million reversal of Interest expense and nil for penalties (2014 – $1 million increase of Interest expense and nil for penalties; 2013 – $1 million reversal for Interest expense and nil for penalties). At December 31, 2015, the Company had $4 million accrued for Interest expense and nil accrued for penalties (December 31, 2014 –$5 million accrued for Interest expense and nil accrued for penalties).

16. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2015 Outstanding at December 31	2015 Interest Rate[1]	2014 Outstanding at December 31	2014 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2017 to 2020	**599**	**10.7%**	749	10.9%
U.S. (2015 and 2014 – US$400)	2021	**554**	**9.9%**	464	9.9%
Medium-Term Notes					
Canadian	2016 to 2041	**5,192**	**5.3%**	4,048	5.7%
Senior Unsecured Notes					
U.S. (2015 – US$14,723; 2014 – US$13,526)	2016 to 2045	**20,340**	**4.8%**	15,655	5.0%
		26,685		20,916	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian[2]	2016 to 2024	**325**	**11.5%**	325	11.5%
U.S. (2015 and 2014 – US$200)	2023	**277**	**7.9%**	232	7.9%
Medium-Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2015 and 2014 – US$33)	2026	**45**	**7.5%**	38	7.5%
		1,151		1,099	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2015 and 2014 – US$432)	2021 to 2025	**598**	**8.9%**	502	8.9%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2015 – US$75)	2019	**104**	**1.4%**	—	—
Senior Unsecured Notes					
U.S. (2015 – US$250; 2014 – US$325)	2020 to 2035	**346**	**5.6%**	377	5.5%
		450		377	
TC PIPELINES, LP					
Unsecured Loan					
U.S. (2015 – US$200; 2014 – US$330)	2017	**277**	**1.6%**	383	1.4%
Unsecured Term Loan Facility					
U.S. (2015 and 2014 – US$500)	2018	**692**	**1.6%**	580	1.4%
Unsecured Term Loan					
U.S. (2015 – US$170)	2018	**235**	**1.6%**	—	—
Senior Unsecured Notes					
U.S. (2015 – US$698; 2014 – US$350)	2021 to 2025	**967**	**4.7%**	405	4.7%
		2,171		1,368	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2015 – US$297; 2014 – US$316)	2018 to 2030	**411**	**7.8%**	367	7.8%

TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. (2015 – US$16; 2014 – US$20)	2017	**22**	**4.0%**	23	4.0%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. (2015 – US$69; 2014 – US$90)	2018	**96**	**6.1%**	105	6.1%
		31,584		24,757	
Less: Current portion of Long-term debt		**2,547**		1,797	
		29,037		22,960	

1 Interest rates are the effective interest rates except for those pertaining to Long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Debentures issued by NGTL in the amount of $225 million have retraction provisions that entitle the holders to periodically require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made in 2015 or 2014.

3 Secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

At December 31, 2015, principal repayments on the Long-term debt of the Company for the nextfive years are approximately as follows:

(millions of Canadian $)	**2016**	**2017**	**2018**	**2019**	**2020**
Principal repayments on Long-term debt	2,547	2,150	3,379	1,228	1,801

Long-Term Debt Issued

The Company issued Long-term debt over the three years ended December 31, 2015 as follows:

(millions of Canadian $, unless otherwise noted)

Company	Issue date	Type	Maturity date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	November 2015	Senior Unsecured Notes	November 2017	US 1,000	1.625%
	October 2015	Medium-Term Notes	November 2041	400	4.55%
	July 2015	Medium-Term Notes	July 2025	750	3.30%
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US 1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US 625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US 625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US 500	Floating
	July 2013	Medium-Term Notes	July 2023	450	3.69%
	July 2013	Medium-Term Notes	November 2041	300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US 750	0.75%
TC PIPELINES, LP					
	September 2015	Unsecured Term Loan	October 2018	US 170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
	July 2013	Unsecured Term Loan Facility	July 2018	US 500	Floating
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

Long-Term Debt Retired

The Company retired Long-term debt over the three years ended December 31, 2015 as follows:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement date**	**Type**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED				
	August 2015	Debentures	150	11.90%
	June 2015	Senior Unsecured Notes	US 500	3.40%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
	June 2014	Debentures	125	11.10%
	February 2014	Medium-Term Notes	300	5.05%
	January 2014	Medium-Term Notes	450	5.65%
	August 2013	Senior Unsecured Notes	US 500	5.05%
	June 2013	Senior Unsecured Notes	US 350	4.00%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%
NOVA GAS TRANSMISSION LTD.				
	June 2014	Debentures	53	11.20%

Interest Expense

Interest expense over the three years ended December 31 was as follows:

year ended December 31 (millions of Canadian $)	**2015**	**2014**	**2013**
Interest on Long-term debt	**1,487**	1,317	1,216
Interest on Junior subordinated notes (Note 17)	**116**	70	65
Interest on short-term debt	**16**	15	12
Capitalized interest	**(280)**	(259)	(287)
Amortization and other financial charges[1]	**31**	55	(21)
	1,370	1,198	985

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $1,266 million in 2015 (2014 – $1,123 million; 2013 – $985 million) on Long-term debt, Junior subordinated notes and Notes payable, net of interest capitalized.

17. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2015 Outstanding at December 31	2015 Effective Interest Rate	2014 Outstanding at December 31	2014 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. (2015 and 2014 – US$1,000)[1]	2067	**1,384**	**6.4%**	1,160	6.5%
U.S. (2015 – US$750)[1]	2075	**1,038**	**5.3%**	—	—
		2,422		1,160	

1 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.

Junior subordinated notes of US$1.0 billion mature in May 2067 and bear interest at6.35 per cent per annum until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate (LIBOR) plus 2.21 per cent. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default or permitting acceleration of payment under the terms of the Junior subordinated notes, however, the Company would be prohibited from paying dividends during any such deferral period. The Junior subordinated notes are callable at the Company's option at any time on or after May 15, 2017 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption. The Junior subordinated notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with their terms.

In May 2015, TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL, issuedUS$750 million Trust Notes - Series 2015-A (Trust Notes) to third party investors at a fixed interest rate of 5.625 per cent for the first 10 years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$750 million of Junior subordinated notes of TCPL at a rate of5.875 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum. The Junior subordinated notes of TCPL are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with other outstanding first preferred shares of TCPL.

18. NON-CONTROLLING INTERESTS

The Company's Non-controlling interests included in the Consolidated balance sheet are as follows:

at December 31 (millions of Canadian $)	2015	2014
Non-controlling interest in TC PipeLines, LP	**1,590**	1,479
Non-controlling interest in PNGTS	**127**	104
	1,717	1,583

The Company's Non-controlling interests included in the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	2015	2014	2013
Non-controlling interest in TC PipeLines, LP	**(13)**	136	93
Non-controlling interest in PNGTS	**19**	15	12
Preferred shares of TCPL	**—**	2	20
	6	153	125

During 2015, the Non-controlling interest in TC PipeLines, LP increased from71.7 per cent to 72.0 per cent due to periodic issuances of common units in TC PipeLines, LP to non-controlling interests. In 2014, the Non-controlling interest in TC PipeLines, LP ranged between 71.1 per cent and 71.7 per cent and, in 2013, between 66.7 per cent and 71.1 per cent.

At December 31, 2015, TC PipeLines, LP recorded an impairment charge ofUS$199 million related to its equity investment in Great Lakes. The Non-controlling interest's share of this charge was US$143 million and is included in the $13 million Non-controlling interest in TC PipeLines, LP in the Consolidated statement of income.

The Non-controlling interest in PNGTS as at December 31,2015 represented the 38.3 per cent interest held by third parties (2014 and 2013 – 38.3 per cent).

In 2015, TransCanada received fees of $4 million from TC PipeLines, LP (2014 and 2013 – $3 million) and $11 million from PNGTS (2014 – $8 million; 2013 – $7 million) for services provided.

On March 5, 2014, TCPL redeemed all of itsfour 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.

On October 15, 2013, TCPL redeemed all of its four million outstanding 5.60 per cent cumulative redeemable first preferred shares Series U at a price of$50 per share plus $0.5907 representing accrued and unpaid dividends to the redemption date.

19. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2013	705,461	12,069
Exercise of options	1,980	80
Outstanding at December 31, 2013	707,441	12,149
Exercise of options	1,221	53
Outstanding at December 31, 2014	708,662	12,202
Exercise of options	**737**	**30**
Repurchase of shares	**(6,785)**	**(130)**
Outstanding at December 31, 2015	**702,614**	**12,102**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Common Shares Repurchased

On November 19, 2015, the Company received approval from the Toronto Stock Exchange (TSX) for a normal course issuer bid (NCIB) allowing it to repurchase, for cancellation, up to 21,270,257 of its common shares representing three per cent of the issued and outstanding common shares. Under the NCIB, which expires on November 22, 2016, the Company may purchase these common shares through the facilities of the TSX, the New York Stock Exchange and other designated exchanges and published markets in both Canada and the U.S., or through off-exchange block purchases by way of private agreement.

In December 2015, the Company repurchased 6,784,738 of its common shares at an average price of $43.29 for a total of $294 million (weighted average cost of $130 million). The difference of $164 million between the total price paid and the weighted average cost was recorded in Additional paid-in capital.

Basic and Diluted Net (Loss)/Income per Share

Net (loss)/income per common share is calculated by dividing Net (loss)/income attributable to common shares by the weighted average number of common shares outstanding. The higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TransCanada's Stock Option Plan.

Weighted Average Common Shares Outstanding (millions)	**2015**	**2014**	**2013**
Basic	**709**	708	707
Diluted	**709**	710	708

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Price	Options Exercisable (thousands)
Outstanding at January 1, 2013	7,434	$37.69	4,568
Granted	1,939	$47.09	
Exercised	(1,980)	$36.12	
Outstanding at December 31, 2013	7,393	$40.57	3,914
Granted	2,292	$49.03	
Exercised	(1,221)	$43.00	
Outstanding at December 31, 2014	8,464	$43.17	4,556
Granted	**2,214**	**$56.58**	
Exercised	**(737)**	**$36.14**	
Forfeited	**(107)**	**$50.74**	
Outstanding at December 31, 2015	**9,834**	**$46.63**	**5,566**

Stock options outstanding at December 31, 2015 were as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options (thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (years)	Number of Options (thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (years)
$31.93 to $36.26	970	$34.27	0.9	970	$34.27	0.9
$36.90 to $41.65	888	$37.91	2.1	888	$37.91	2.1
$41.95 to $45.29	1,759	$42.04	3.2	1,759	$42.04	3.2
$47.09	1,800	$47.09	4.1	1,195	$47.09	4.1
$49.03	2,242	$49.03	5.2	754	$49.03	5.2
$56.58	2,175	$56.58	6.2	—	—	0.0
	9,834	**$46.63**	**4.1**	**5,566**	**$42.04**	**3.1**

An additional 6,123,649 common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2015. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $6.45 for the year ended December 31, 2015 (2014 – $5.54; 2013 – $5.74). The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	2015	2014	2013
Expected life (years)	**5.8**	6.0	6.0
Interest rate	**1.1%**	1.8%	1.7%
Volatility[1]	**18%**	17%	18%
Dividend yield	**3.7%**	3.8%	3.7%
Forfeiture rate	**5%**	5%	15%

[1] Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $11 million in 2015 (2014 – $9 million; 2013 – $6 million).

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2015	2014	2013
Total intrinsic value of options exercised	**37**	68	25
Fair value of options that have vested	**91**	95	64
Total options vested	**2.0 million**	1.7 million	1.3 million

As at December 31, 2015, the aggregate intrinsic value of the total options exercisable was $23 million and the total intrinsic value of options outstanding was $23 million.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to provide the Board of Directors (Board) with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase two common shares of the Company for the then current market price of one.

20. PREFERRED SHARES

at December 31	Number of Shares Authorized and Outstanding (thousands)	Current Yield	Annual Dividend Per Share[1]	Redemption Price Per Share[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]	2015 (millions of Canadian $)[6]	2014 (millions of Canadian $)[6]
Cumulative First Preferred Shares[5]								
Series 1	9,498	3.266%	$0.8165	$25.00	December 31, 2019	Series 2	**233**	233
Series 2	12,502	Floating[7]	Floating	$25.00	December 31, 2019	Series 1	**306**	306
Series 3	8,533	2.152%	$0.538	$25.00	June 30, 2020	Series 4	**209**	343
Series 4	5,467	Floating[7]	Floating	$25.00	June 30, 2020	Series 3	**134**	—
Series 5	14,000	4.40%	$1.10	$25.00	January 30, 2016	Series 6	**342**	342
Series 7	24,000	4.00%	$1.00	$25.00	April 30, 2019	Series 8	**589**	589
Series 9	18,000	4.25%	$1.0625	$25.00	October 30, 2019	Series 10	**442**	442
Series 11	10,000	3.80%	$0.95	$25.00	November 30, 2020	Series 12	**244**	—
							2,499	2,255

1 The holder is entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2 and Series 4 preferred shares. The holders of Series 2 and Series 4 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends as and when declared by the Board.

2 TransCanada may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2 and Series 4 preferred shares are redeemable by TransCanada at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date, in which case they are redeemable at $25.00 per share plus all accrued and unpaid dividends.

3 The holder will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

4 Each of the even numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10) and 2.96 per cent (Series 12). These rates will reset each quarter going forward.

5 The odd numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends which will reset on the redemption and conversion option date and every fifth year thereafter, equal to an annualized rate equal to the then five-year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), and 2.96 per cent (Series 11).

6 Net of underwriting commissions and deferred income taxes.

7 Commencing December 31, 2015, the floating quarterly dividend rate for the Series 2 preferred shares is 2.418 per cent and the Series 4 preferred shares is 1.778 per cent for the period starting December 31, 2015 to, but excluding, March 31, 2016. These rates will reset each quarter going forward.

In March 2015, TransCanada completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at a price of $25.00 per share, resulting in gross proceeds of $250 million.

In June 2015, holders of 5,466,595 Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 cumulative redeemable first preferred shares and receive quarterly floating rate, cumulative, dividends at an annualized rate equal to the applicable 90-day Government of Canada Treasury Bill rate plus 1.28 per cent which will reset every quarter going forward. The 8,533,405 Series 3 preferred shares will pay on a quarterly basis, for the five year period beginning on June 30, 2015, a fixed quarterly dividend based on an annualized dividend rate of 2.152 per cent.

21. OTHER COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of Other comprehensive income/(loss), including the portion attributable to non-controlling interests and related tax effects, are as follows:

year ended December 31, 2015 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/(Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	**798**	**15**	**813**
Change in fair value of net investment hedges	**(505)**	**133**	**(372)**
Change in fair value of cash flow hedges	**(92)**	**35**	**(57)**
Reclassification to net income of gains and losses on cash flow hedges	**144**	**(56)**	**88**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**74**	**(23)**	**51**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**41**	**(9)**	**32**
Other comprehensive income on equity investments	**62**	**(15)**	**47**
Other Comprehensive Income	**522**	**80**	**602**

year ended December 31, 2014 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/(Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	462	55	517
Change in fair value of net investment hedges	(373)	97	(276)
Change in fair value of cash flow hedges	(118)	49	(69)
Reclassification to net income of gains and losses on cash flow hedges	(95)	40	(55)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(146)	44	(102)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	25	(7)	18
Other comprehensive loss on equity investments	(272)	68	(204)
Other Comprehensive Loss	(517)	346	(171)

year ended December 31, 2013 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/(Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	269	114	383
Change in fair value of net investment hedges	(323)	84	(239)
Change in fair value of cash flow hedges	121	(50)	71
Reclassification to net income of gains and losses on cash flow hedges	60	(19)	41
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	96	(29)	67
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	34	(11)	23
Other comprehensive income on equity investments	313	(79)	234
Other Comprehensive Income	570	10	580

The changes in AOCI by component are as follows:

	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2013	(707)	(116)	(287)	(338)	(1,448)
Other comprehensive income before reclassifications[2]	78	71	67	219	435
Amounts reclassified from accumulated other comprehensive loss	—	41	23	15	79
Net current period other comprehensive income	78	112	90	234	514
AOCI balance at December 31, 2013	(629)	(4)	(197)	(104)	(934)
Other comprehensive income/(loss) before reclassifications[2]	111	(69)	(102)	(206)	(266)
Amounts reclassified from accumulated other comprehensive loss	—	(55)	18	2	(35)
Net current period other comprehensive income/(loss)	111	(124)	(84)	(204)	(301)
AOCI balance at December 31, 2014	(518)	(128)	(281)	(308)	(1,235)
Other comprehensive income/(loss) before reclassifications[2]	**135**	**(57)**	**51**	**33**	**162**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**88**	**32**	**14**	**134**
Net current period other comprehensive income	**135**	**31**	**83**	**47**	**296**
AOCI balance at December 31, 2015	**(383)**	**(97)**	**(198)**	**(261)**	**(939)**

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 $306 million in 2015 (2014 – $130 million gains; 2013 – $66 million gains).

3 Losses 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 $83 million ($51 million, net of tax) at December 31, 2015. 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 AOCI into the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	Amounts Reclassified From Accumulated Other Comprehensive Loss[1] 2015	2014	2013	Affected Line Item in the Consolidated Statement of Income
Cash flow hedges				
Commodities	**(128)**	111	(44)	Revenues (Energy)
Interest	**(16)**	(16)	(16)	Interest expense
	(144)	95	(60)	Total before tax
	56	(40)	19	Income tax expense/(recovery)
	(88)	55	(41)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial loss and past service cost	**(41)**	(25)	(34)	[2]
	9	7	11	Income tax recovery
	(32)	(18)	(23)	Net of tax
Equity investments				
Equity income	**(19)**	(2)	(20)	Income from equity investments
	5	—	5	Income tax recovery
	(14)	(2)	(15)	Net of tax

1 All amounts in parentheses indicate expenses to the Consolidated statement of income.
2 These Accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 22 for further information.

22. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining service life of employees, which is approximately nine years at December 31, 2015 (2014 and 2013 – nine years).

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2015 (2014 – 12 years; 2013 – 11 years). In 2015, the Company expensed $41 million (2014 – $37 million; 2013 – $29 million) for the savings and DC Plans.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	2015	2014	2013
DB Plans	**96**	73	79
Other post-retirement benefit plans	**6**	6	6
Savings and DC Plans	**41**	37	29
	143	116	114

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, the Company provided a $33 million letter of credit to the Canadian DB Plan in 2015 (2014 – $47 million; 2013 – $59 million), resulting in a total of $214 million provided to the Canadian DB Plan under letters of credit at December 31, 2015.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2015 and the next required valuation will be as at January 1, 2016.

The Company's funded status at December 31 is comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**2,658**	2,224	**216**	191
Service cost	**108**	85	**3**	2
Interest cost	**115**	113	**10**	10
Employee contributions	**4**	4	**—**	—
Benefits paid	**(129)**	(102)	**(7)**	(7)
Actuarial (gain)/loss	**(57)**	302	**(11)**	14
Foreign exchange rate changes	**81**	32	**14**	6
Benefit obligation – end of year	**2,780**	2,658	**225**	216
Change in Plan Assets				
Plan assets at fair value – beginning of year	**2,398**	2,152	**39**	35
Actual return on plan assets	**160**	246	**(1)**	2
Employer contributions[2]	**96**	73	**6**	6
Employee contributions	**4**	4	**—**	—
Benefits paid	**(129)**	(102)	**(7)**	(7)
Foreign exchange rate changes	**62**	25	**8**	3
Plan assets at fair value – end of year	**2,591**	2,398	**45**	39
Funded Status – Plan Deficit	**(189)**	(260)	**(180)**	(177)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation

2 Excludes $214 million in letters of credit provided to the Canadian DB Plans for funding purposes (2014 – $181 million).

The amounts recognized in the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Intangible and other assets (Note 11)	**—**	—	**18**	14
Accounts payable and other	**—**	—	**(7)**	(7)
Other long-term liabilities (Note 14)	**(189)**	(260)	**(191)**	(184)
	(189)	(260)	**(180)**	(177)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Projected benefit obligation[1]	**(2,780)**	(2,658)	**(198)**	(191)
Plan assets at fair value	**2,591**	2,398	**—**	—
Funded Status – Plan Deficit	**(189)**	(260)	**(198)**	(191)

[1] The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31		
(millions of Canadian $)	**2015**	**2014**
Accumulated benefit obligation	**(2,600)**	(2,437)
Plan assets at fair value	**2,591**	2,398
Funded Status – Plan Deficit	**(9)**	(39)

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31		
(millions of Canadian $)	**2015**	**2014**
Accumulated benefit obligation	**(807)**	(715)
Plan assets at fair value	**680**	597
Funded Status – Plan Deficit	**(127)**	(118)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

	Percentage of Plan Assets		Target Allocations
at December 31	**2015**	**2014**	**2015**
Debt securities	**34%**	31%	**25% to 35%**
Equity securities	**66%**	69%	**50% to 70%**
Alternatives	—	—	**5 % to 15%**
	100%	100%	

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Debt securities	**2**	1	**0.1%**	0.1%
Equity securities	**4**	1	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For further information on the fair value hierarchy, refer to Note 23.

at December 31	**Quoted Prices in Active Markets (Level I)**		**Significant Other Observable Inputs (Level II)**		**Significant Unobservable Inputs (Level III)**		**Total**		**Percentage of Total Portfolio**	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Asset Category										
Cash and Cash Equivalents	**44**	20	**2**	—	**—**	—	**46**	20	**2**	1
Equity Securities:										
Canadian	**317**	361	**147**	142	**—**	—	**464**	503	**17**	21
U.S.	**589**	516	**40**	35	**—**	—	**629**	551	**24**	23
International	**38**	218	**300**	147	**—**	—	**338**	365	**13**	15
Global	**—**	—	**154**	141	**—**	—	**154**	141	**6**	6
Emerging	**7**	7	**143**	80	**—**	—	**150**	87	**6**	3
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**206**	218	**—**	—	**206**	218	**8**	9
Provincial	**—**	—	**202**	180	**—**	—	**202**	180	**8**	7
Municipal	**—**	—	**7**	7	**—**	—	**7**	7	**—**	—
Corporate	**—**	—	**113**	76	**—**	—	**113**	76	**4**	3
U.S. Bonds:										
State	**—**	—	**50**	47	**—**	—	**50**	47	**2**	2
Corporate	**—**	—	**57**	59	**—**	—	**57**	59	**2**	2
International:										
Corporate	**—**	—	**25**	14	**—**	—	**25**	14	**1**	1
Mortgage backed	**—**	—	**58**	39	**—**	—	**58**	39	**2**	2
Other Investments:										
Private equity funds	**—**	—	**—**	—	**14**	13	**14**	13	**—**	—
Funds held on deposit	**123**	117	**—**	—	**—**	—	**123**	117	**5**	5
	1,118	1,239	**1,504**	1,185	**14**	13	**2,636**	2,437	**100**	100

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	Private Equity Funds
Balance at December 31, 2013	18
Purchases and sales	(7)
Realized and unrealized gains	2
Balance at December 31, 2014	13
Purchases and sales	**(1)**
Realized and unrealized gains	**2**
Balance at December 31, 2015	**14**

The Company's expected funding contributions in 2016 are approximately $70 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $37 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $33 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian $)		Pension Benefits	Other Post-Retirement Benefits
	2016	129	8
	2017	133	9
	2018	138	9
	2019	142	9
	2020	146	10
2021 to 2025		808	51

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2015. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2015**	**2014**	**2015**	**2014**
Discount rate	**4.20%**	4.15%	**4.40%**	4.20%
Rate of compensation increase	**0.50%**	3.15%	**—%**	—%

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Discount rate	**4.15%**	4.95%	4.35%	**4.20%**	5.00%	4.35%
Expected long-term rate of return on plan assets	**6.95%**	6.90%	6.70%	**4.60%**	4.60%	4.60%
Rate of compensation increase	**3.15%**	3.15%	3.15%	—	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A seven per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2021 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian $)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	14	(12)

The Company's net benefit cost recognized is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Service cost	**108**	85	84	**3**	2	2
Interest cost	**115**	113	96	**10**	10	7
Expected return on plan assets	**(155)**	(139)	(120)	**(2)**	(2)	(2)
Amortization of actuarial loss	**35**	21	30	**3**	2	2
Amortization of past service cost	**2**	2	2	**1**	—	—
Amortization of regulatory asset	**23**	18	30	**1**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**2**	2	2
Net Benefit Cost Recognized	**128**	100	122	**18**	15	12

Pre-tax amounts recognized in AOCI were as follows:

	2015		2014		2013	
at December 31 (millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**247**	**28**	348	39	236	32
Prior service cost	**—**	**—**	2	1	3	1
	247	**28**	350	40	239	33

The estimated net loss for the DB Plans and for the other post-retirement benefit plans that will be amortized from AOCI into net periodic benefit cost in 2016 is $21 million and $3 million respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31 (millions of Canadian $)	2015		2014		2013	
	Pension Benefits	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net loss from AOCI to OCI	**(34)**	**(4)**	(21)	(2)	(30)	(2)
Amortization of prior service costs from AOCI to OCI	**(2)**	**(1)**	(2)	—	(2)	—
Funded status adjustment	**(67)**	**(7)**	137	9	(96)	—
	(103)	**(12)**	114	7	(128)	(2)

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

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

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to assist in managing the exposure to market risk that results from these activities. These derivative contracts may consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations. A number of strategies are used to manage these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in its asset portfolio.
- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or through purchased contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

Natural Gas Storage Commodity Price Risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TransCanada’s earnings from its Natural Gas Pipelines, Liquids Pipelines and Energy segments are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada’s net income. As the Company’s U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases; some of this foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt of the Company's foreign operations and by using foreign exchange derivatives.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to other U.S. dollar-denominated transactions including those that may arise on some of the Company’s regulated assets. The realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

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

at December 31 (millions of Canadian $, unless otherwise noted)	2015	2014
Carrying value	**23,000 (US 16,600)**	17,000 (US 14,700)
Fair value	**23,800 (US 17,200)**	19,000 (US 16,400)

Derivatives Designated as a Net Investment Hedge

at December 31 (millions of Canadian $, unless otherwise noted)	2015 Fair Value[1]		2015 Notional or Principal Amount	2014 Fair Value[1]		2014 Notional or Principal Amount
U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2]	**(730)**	**US**	**3,150**	(431)	US	2,900
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**50**	**US**	**1,800**	(28)	US	1,400
	(680)	**US**	**4,950**	(459)	US	4,300

1 Fair values equal carrying values.
2 In 2015, net realized gains of $8 million (2014 – gains of $21 million) related to the interest component of cross-currency swap settlements are included in Interest expense.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the related contract or agreement with the Company.

The Company manages its exposure to this potential loss by using recognized credit management techniques, including:

- Dealing with creditworthy counterparties – a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- Setting limits on the amount TransCanada can transact with any one counterparty – the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when necessary and when it is allowed under the terms of the contracts
- Using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when deemed necessary.

There is no guarantee that these techniques will protect the Company from material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at December 31, 2015, without taking into account security held, consisted of accounts receivable, available for sale assets recorded at fair value, the fair value of derivative assets, notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2015, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

The Company had a credit risk concentration due from a counterparty of $248 million (US$179 million) and $258 million (US$222 million) at December 31, 2015 and 2014, respectively. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

TransCanada has significant credit and performance exposures to financial institutions as they hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Fair Value of Non-Derivative Financial Instruments

The fair value of the Company's Notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-term debt and Junior subordinated notes is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. 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 approximate their fair value due to the nature of the item or the short time to maturity and would also be classified in Level II of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

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 approximate fair value, and would be classified in Level II of the fair value hierarchy:

at December 31 (millions of Canadian $)	2015 Carrying Amount	2015 Fair Value	2014 Carrying Amount	2014 Fair Value
Notes receivable[1]	**214**	**265**	213	263
Current and Long-term debt[2,3] (Note 16)	**(31,584)**	**(34,309)**	(24,757)	(28,713)
Junior subordinated notes (Note 17)	**(2,422)**	**(2,011)**	(1,160)	(1,157)
	(33,792)	**(36,055)**	(25,704)	(29,607)

1 Notes receivable are included in Other current assets and Intangible and other assets on the Consolidated balance sheet.

2 Long-term debt is recorded at amortized cost, except for US$850 million (2014 – US$400 million) that is attributed to hedged risk and recorded at fair value.

3 Consolidated Net income in 2015 included gains of $2 million (2014 – losses of $3 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$850 million of Long-term debt at December 31, 2015 (2014 – US$400 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for Sale Assets Summary

The following tables summarize additional information about the Company's restricted investments that are classified as available for sale assets:

at December 31 (millions of Canadian $)	2015 LMCI Restricted Investments[1]	2015 Other Restricted Investments[2]	2014 LMCI Restricted Investments[1]	2014 Other Restricted Investments[2]
Fair values				
Fixed income securities (maturing within 5 years)	**—**	**90**	—	75
Fixed income securities (maturing after 10 years)	**261**	**—**	—	—
	261	**90**	—	75

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company would record these gains and losses as regulatory assets or liabilities. In 2015 and 2014, there were no net realized or unrealized gains or losses on LMCI restricted investments.

2 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary. In 2015 and 2014, there were no net realized or unrealized gains or losses on other restricted investments.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives 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. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

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 or are not designated as a hedge 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 as atDecember 31, 2015 is as follows:

at December 31, 2015 (millions of Canadian $)	Cash Flow Hedges[1]	Fair Value Hedges[1]	Net Investment Hedges[1]	Held for Trading[1]	Total Fair Value of Derivative Instruments
Other current assets (Note 5)					
Commodities[2]	**46**	**—**	**—**	**326**	**372**
Foreign exchange	**—**	**—**	**65**	**2**	**67**
Interest rate	**—**	**1**	**—**	**2**	**3**
	46	**1**	**65**	**330**	**442**
Intangible and other assets (Note 11)					
Commodities[2]	**11**	**—**	**—**	**126**	**137**
Foreign exchange	**—**	**—**	**29**	**—**	**29**
Interest rate	**—**	**2**	**—**	**—**	**2**
	11	**2**	**29**	**126**	**168**
Total Derivative Assets	**57**	**3**	**94**	**456**	**610**
Accounts payable and other (Note 13)					
Commodities[2]	**(112)**	**—**	**—**	**(443)**	**(555)**
Foreign exchange	**—**	**—**	**(313)**	**(54)**	**(367)**
Interest rate	**(1)**	**(1)**	**—**	**(2)**	**(4)**
	(113)	**(1)**	**(313)**	**(499)**	**(926)**
Other long-term liabilities (Note 14)					
Commodities[2]	**(31)**	**—**	**—**	**(131)**	**(162)**
Foreign exchange	**—**	**—**	**(461)**	**—**	**(461)**
Interest rate	**(1)**	**(1)**	**—**	**—**	**(2)**
	(32)	**(1)**	**(461)**	**(131)**	**(625)**
Total Derivative Liabilities	**(145)**	**(2)**	**(774)**	**(630)**	**(1,551)**

1 Fair value equals carrying value.
2 Includes purchases and sales of power and natural gas.

The balance sheet classification of the fair value of the derivative instruments as atDecember 31, 2014 is as follows:

at December 31, 2014 (millions of Canadian $)	Cash Flow Hedges[1]	Fair Value Hedges[1]	Net Investment Hedges[1]	Held for Trading[1]	Total Fair Value of Derivative Instruments
Other current assets (Note 5)					
Commodities[2]	39	—	—	359	398
Foreign exchange	—	—	5	1	6
Interest rate	—	2	—	3	5
	39	2	5	363	409
Intangible and other assets (Note 11)					
Commodities[2]	18	—	—	72	90
Foreign exchange	—	—	1	—	1
Interest rate	—	1	—	1	2
	18	1	1	73	93
Total Derivative Assets	57	3	6	436	502
Accounts payable and other (Note 13)					
Commodities[2]	(136)	—	—	(422)	(558)
Foreign exchange	—	—	(155)	(32)	(187)
Interest rate	(1)	—	—	(3)	(4)
	(137)	—	(155)	(457)	(749)
Other long-term liabilities (Note 14)					
Commodities[2]	(27)	—	—	(72)	(99)
Foreign exchange	—	—	(310)	—	(310)
Interest rate	(1)	—	—	(1)	(2)
	(28)	—	(310)	(73)	(411)
Total Derivative Liabilities	(165)	—	(465)	(530)	(1,160)

1 Fair value equals carrying value.
2 Includes purchases and sales of power and natural gas.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all 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.

Notional and Maturity Summary

The following tables present the maturity and notional principal or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations:

at December 31, 2015	Power	Natural Gas	Foreign Exchange	Interest
Purchases[1]	**70,331**	**133**	**—**	**—**
Sales[1]	**54,382**	**70**	**—**	**—**
Millions of dollars	**—**	**—**	**US 1,476**	**US 1,100**
Maturity dates	**2016–2020**	**2016–2020**	**2016**	**2016–2019**

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

at December 31, 2014	Power	Natural Gas	Foreign Exchange	Interest
Purchases[1]	53,217	60	—	—
Sales[1]	39,429	38	—	—
Millions of dollars	—	—	US 1,374	US 650
Maturity dates	2015–2019	2015–2020	2015	2015–2018

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

Unrealized and Realized (Losses)/Gains of Derivative Instruments

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

year ended December 31 (millions of Canadian $)	2015	2014
Derivative instruments held for trading[1]		
Amount of unrealized losses in the year		
Commodities	**(37)**	(40)
Foreign exchange	**(21)**	(20)
Amount of realized losses in the year		
Commodities	**(151)**	(28)
Foreign exchange	**(112)**	(28)
Derivative instruments in hedging relationships[2,3]		
Amount of realized (losses)/gains in the year		
Commodities	**(179)**	130
Interest rate	**8**	4

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell commodities are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest expense and Interest income and other, respectively.

2 In 2015, net realized gains on fair value hedges were $11 million (2014 – gains of $7 million) and were included in Interest expense.

3 In 2015 and 2014, 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 OCI (Note 21) related to derivatives in cash flow hedging relationships are as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2015	2014
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(92)**	(128)
Foreign exchange	**—**	10
	(92)	(118)
Reclassification of gains/(losses) on derivative instruments from AOCI to Net income (effective portion)[1]		
Commodities[2]	**128**	(111)
Interest rate[3]	**16**	16
	144	(95)
Losses on derivative instruments recognized in Net income (ineffective portion)		
Commodities[2]	**—**	(13)

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

2 Reported within Revenues on the Consolidated statement of income.
3 Reported within Interest expense on the Consolidated statement of income.

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 Consolidated 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 December 31, 2015 (millions of Canadian $)	**Gross Derivative Instruments Presented on the Balance Sheet**	**Amounts Available for Offset**[1]	**Net Amounts**
Derivative - Asset			
Commodities	**509**	**(418)**	**91**
Foreign exchange	**96**	**(93)**	**3**
Interest rate	**5**	**(1)**	**4**
	610	**(512)**	**98**
Derivative - Liability			
Commodities	**(717)**	**418**	**(299)**
Foreign exchange	**(828)**	**93**	**(735)**
Interest rate	**(6)**	**1**	**(5)**
	(1,551)	**512**	**(1,039)**

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

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, 2014:

at December 31, 2014 (millions of Canadian $)	**Gross Derivative Instruments Presented on the Balance Sheet**	**Amounts Available for Offset**[1]	**Net Amounts**
Derivative - Asset			
Commodities	488	(387)	101
Foreign exchange	7	(7)	—
Interest rate	7	(1)	6
	502	(395)	107
Derivative - Liability			
Commodities	(657)	387	(270)
Foreign exchange	(497)	7	(490)
Interest rate	(6)	1	(5)
	(1,160)	395	(765)

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

With respect to the derivative instruments presented above as at December 31, 2015, the Company had provided cash collateral of $482 million (2014 – $459 million) and letters of credit of $41 million (2014 – $26 million) to its counterparties. The Company held nil (2014 – $1 million) in cash collateral and $2 million (2014 – $1 million) in letters of credit from counterparties on asset exposures at December 31, 2015.

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 December 31, 2015, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $32 million (2014 – $15 million), for which the Company has provided collateral in the normal course of business of nil (2014 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2015, the Company would have been required to provide additional collateral of $32 million (2014 – $15 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 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 financial assets and liabilities recorded at fair value have been categorized into three categories based on a 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	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. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the fair value of the derivatives. This category includes long-dated commodity transactions in certain markets where liquidity is low and inputs may include long-term broker quotes. Valuation of options is based on the Black-Scholes pricing model. Long-term electricity prices may also be estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. 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 might be estimated 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, increases in the supply of electricity or natural gas, or a small number of transactions in markets with lower liquidity are expected to or may result in a lower fair value measurement of contracts included in Level III. 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 significant 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.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2015, are categorized as follows:

at December 31, 2015 (millions of Canadian $)	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:				
Commodities	**34**	**462**	**13**	**509**
Foreign exchange	**—**	**96**	**—**	**96**
Interest rate	**—**	**5**	**—**	**5**
Derivative Instrument Liabilities:				
Commodities	**(102)**	**(611)**	**(4)**	**(717)**
Foreign exchange	**—**	**(828)**	**—**	**(828)**
Interest rate	**—**	**(6)**	**—**	**(6)**
	(68)	**(882)**	**9**	**(941)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2015.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2014, are categorized as follows:

at December 31, 2014 (millions of Canadian $)	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:				
Commodities	40	441	7	488
Foreign exchange	—	7	—	7
Interest rate	—	7	—	7
Derivative Instrument Liabilities:				
Commodities	(86)	(568)	(3)	(657)
Foreign exchange	—	(497)	—	(497)
Interest rate	—	(6)	—	(6)
	(46)	(616)	4	(658)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2014.

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

(millions of Canadian $, pre-tax)	2015	2014
Balance at beginning of year	**4**	1
Transfers out of Level III	**5**	—
Total gains included in Net income	**3**	3
Sales	**(2)**	—
Settlements	**(1)**	—
Balance at end of year[1]	**9**	4

1 Revenues include unrealized gains attributed to derivatives in the Level III category that were still held at December 31, 2015 of $7 million (2014 – $3 million).

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 December 31, 2015.

24. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2015	2014	2013
Increase in Accounts receivable	**(66)**	(189)	(54)
Increase in Inventories	**(3)**	(28)	(30)
(Increase)/decrease in Other current assets	**(267)**	(385)	40
(Decrease)/increase in Accounts payable and other	**(153)**	377	(290)
Increase in Accrued interest	**91**	36	8
Increase in Operating Working Capital	**(398)**	(189)	(326)

25. ACQUISITIONS AND DISPOSITIONS

Natural Gas Pipelines

TC PipeLines, LP

On April 1, 2015, TransCanada completed the sale of its remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to TC PipeLines, LP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN LLC debt and US$95 million of new Class B units of TC PipeLines, LP.

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.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of US$43.85 per unit, resulting in gross proceeds of approximately US$388 million and net proceeds of US$373 million after unit issuance costs. TransCanada contributed approximately US$8 million to maintain its two per cent general partnership interest and did not purchase any other units. Upon completion of this offering, TransCanada's ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent and an after-tax dilution gain of $29 million ($47 million pre-tax) was recorded in Additional paid-in capital.

In July 2013, TransCanada completed the sale of a 45 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million for the assumption of 45 per cent of GTN LLC debt outstanding, plus normal closing adjustments. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

Gas Pacifico/INNERGY

On November 26, 2014, TransCanada sold its 30 per cent equity investments in Gas Pacifico and INNERGY for aggregate gross proceeds of $9 million and recognized a gain of $9 million ($8 million after-tax).

Energy

Bruce Power

On December 3, 2015, TransCanada exercised its option to acquire an additional 14.89 per cent ownership interest in Bruce B from the Ontario Municipal Employees Retirement System (OMERS) for $236 million, increasing its ownership interest to 46.5 per cent. The difference between the purchase price and the underlying carrying value of Bruce B is primarily related to the estimated fair value of the amended agreement with Ontario's Independent Electricity System Operator to extend the operating life of the Bruce Power facility to 2064. On December 4, 2015, Bruce B and Bruce A merged to form a single limited partnership (Bruce Power). This merger was accounted for as a transaction between entities under common control whereby the assets and liabilities of Bruce A and Bruce B were combined at their carrying values. Upon completion of the merger, TransCanada applied equity accounting to its 48.5 per cent ownership interest in Bruce Power. Prior to the acquisition, TransCanada applied equity accounting to its 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, TransCanada completed the acquisition of four Ontario solar facilities for $241 million in 2014. In 2013, TransCanada completed the acquisition of four solar facilities for

$216 million. The Company's total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year PPAs with the Ontario Power Authority.

Cancarb

On April 15, 2014, TransCanada sold Cancarb Limited and its related power generation for aggregate gross proceeds of $190 million and recognized a gain of $108 million ($99 million after-tax).

26. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments under the Company's operating leases for various premises, services and equipment as well as fixed payments on Alberta PPAs, net of sublease receipts, are approximately as follows:

year ended December 31 (millions of Canadian $)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2016	354	46	308
2017	355	45	310
2018	270	26	244
2019	248	24	224
2020	185	20	165
2021 and thereafter	311	1	310
	1,723	162	1,561

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 25 years. Net rental expense on operating leases in 2015 was $131 million (2014 – $114 million; 2013 – $98 million).

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Fixed payments under these PPAs have been included in the above operating leases table. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. TransCanada's share of payments under the PPAs in 2015 was $348 million (2014 – $391 million; 2013 – $242 million). The generating capacities and expiry dates of the PPAs are as follows:

	MW	Expiry Date
Sundance A	560	December 31, 2017
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

At December 31, 2015, TransCanada was committed to Natural Gas Pipelines capital expenditures totaling approximately $0.9 billion (2014 – $0.9 billion), primarily related to construction costs related to the NGTL System, Mexican and other natural gas pipeline projects.

At December 31, 2015, the Company was committed to Liquids Pipelines capital expenditures totaling approximately$0.8 billion (2014 – $1.8 billion), primarily related to construction costs of Grand Rapids and Northern Courier.

At December 31, 2015, the Company was committed to Energy capital expenditures totaling approximately$0.6 billion (2014 – $0.2 billion), related to capital costs of the Napanee Generating Station. The Company also entered into an agreement to acquire the Ironwood natural gas fired, combined cycle power plant for US$657 million, before post-closing adjustments.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. Asat December 31, 2015, the Company had accrued approximately $32 million (2014 – $31 million; 2013 – $32 million) related to operating facilities, which represents the present value of the estimated future amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

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, other than the Keystone XL legal proceeding described in Note 28, 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, OMERS, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services. 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 redelivery 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:

		2015		2014	
year ended December 31 (millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Bruce Power	Ranging to 2018[2]	**88**	**2**	634	6
Other jointly owned entities	Ranging to 2040	**139**	**24**	104	14
		227	**26**	738	20

1 TransCanada's share of the potential estimated current or contingent exposure.
2 Except for one guarantee with no termination date.

27. CORPORATE RESTRUCTURING COSTS

At December 31, 2015, the Company had incurred$122 million pre-tax of corporate restructuring charges primarily related to severance, and recorded a provision of $87 million pre-tax related to planned severance costs in 2016 and expected losses under lease commitments. Of the total corporate restructuring charges of $209 million pre-tax, $157 million was recorded in Plant operating costs and other in the Consolidated statement of income which was partially offset by $58 million recorded in Revenues in the Consolidated statement of income related to costs that were recoverable through regulatory and tolling structures. In addition, $44 million was recorded as a Regulatory asset on the Consolidated balance sheet, as it is expected to be recovered through regulatory and tolling structures in future periods, and $8 million was capitalized to projects impacted by the corporate restructuring.

28. SUBSEQUENT EVENTS

Portland Natural Gas Transmission System

On January 1, 2016, TransCanada completed the sale of a 49.9 per cent interest in PNGTS to TC PipeLines, LP for an aggregate purchase price of US$223 million.

Keystone XL legal proceeding

On January 6, 2016, TransCanada filed a Notice of Intent to initiate a claim under Chapter 11 of North American Free Trade Agreement (NAFTA) in response to the denial of the U.S. Presidential permit for the Keystone XL Pipeline. Through the NAFTA claim, the Company is seeking to recover more than US$15 billion in costs and damages that it estimates it has suffered as a result of the U.S. Administration's breach of its NAFTA obligations. This litigation is in a preliminary stage and the likelihood of success and resulting impact on the Company's financial position or results of operations is unknown at this time.

U.S. Senior Notes Issue

On January 27, 2016, TCPL completed an offering of US$850 million, 4.875 per cent Senior Notes due January 15, 2026 and US$400 million, 3.125 per cent Senior Notes due January 15, 2019.

Ironwood

On February 1, 2016, TransCanada acquired the Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, with a capacity of 778 MW, for US$657 million, before post-closing adjustments.

Supplementary information

SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

	First	Second	Third	Fourth	Annual
Toronto Stock Exchange (Stock trading symbol TRP)					
2015 (dollars)					
High	**59.50**	**58.12**	**52.16**	**48.44**	**59.50**
Low	**50.51**	**50.15**	**41.10**	**40.58**	**40.58**
Close	**54.16**	**50.76**	**42.20**	**45.19**	**45.19**
Volume (millions of shares)	**84.2**	**79.6**	**84.4**	**124.4**	**372.6**
2014 (dollars)					
High	50.97	51.89	63.86	58.18	63.86
Low	47.14	49.34	50.38	49.30	47.14
Close	50.25	50.93	57.68	57.10	57.10
Volume (millions of shares)	58.6	58.9	104.7	115.0	337.2
2013 (dollars)					
High	50.08	51.21	48.48	48.93	51.21
Low	46.80	44.62	44.75	43.94	43.94
Close	48.50	45.28	45.25	48.54	48.54
Volume (millions of shares)	76.9	85.8	64.3	68.9	295.9
2012 (dollars)					
High	44.75	43.80	46.29	47.44	47.44
Low	40.34	41.47	42.73	43.16	40.34
Close	42.83	42.67	44.74	47.02	47.02
Volume (millions of shares)	95.4	79.3	78.5	66.0	319.2
2011 (dollars)					
High	39.64	43.72	43.23	44.74	44.74
Low	36.10	38.95	37.00	39.25	36.10
Close	39.31	42.35	42.54	44.53	44.53
Volume (millions of shares)	106.9	85.9	107.4	120.6	420.8
New York Stock Exchange (Stock trading symbol TRP)					
2015 (U.S. dollars)					
High	**49.64**	**48.10**	**40.78**	**35.57**	**49.64**
Low	**41.51**	**40.33**	**30.60**	**29.89**	**29.89**
Close	**42.72**	**40.62**	**31.58**	**32.59**	**32.59**
Volume (millions of shares)	**69.9**	**57.9**	**66.4**	**78.1**	**272.3**
2014 (U.S. dollars)					
High	45.81	48.13	58.40	51.84	58.40
Low	42.21	44.78	47.24	43.71	42.21
Close	45.52	47.72	51.53	49.10	49.10
Volume (millions of shares)	31.9	29.5	88.2	99.5	249.0
2013 (U.S. dollars)					
High	49.64	49.65	46.79	46.45	49.65
Low	45.80	42.39	42.59	42.41	42.39
Close	47.89	43.11	43.94	45.66	45.66
Volume (millions of shares)	33.3	38.2	30.3	27.9	129.7
2012 (U.S. dollars)					
High	45.07	44.5	47.02	47.78	47.78
Low	39.74	39.87	41.68	43.54	39.74
Close	43	41.9	45.5	47.32	47.32
Volume (millions of shares)	39.7	29.2	20.1	20.0	109.0
2011 (U.S. dollars)					

High	40.76	45.09	44.08	44.38	45.09
Low	36.12	40.37	37.29	37.58	36.12
Close	40.53	43.84	40.49	43.67	43.67
Volume (millions of shares)	30.3	23.8	51.6	48.5	154.2

Five year financial highlights

(millions of Canadian $, unless otherwise noted)	2015	2014	2013	2012	2011
Income Statement					
Revenues	**11,300**	10,185	8,797	8,007	7,839
EBITDA					
Natural Gas Pipelines	**3,352**	3,250	2,907	2,741	2,875
Liquids Pipelines	**(2,364)**	1,059	752	698	587
Energy	**1,148**	1,360	1,407	862	1,119
Corporate	**(270)**	(127)	(108)	(97)	(86)
	1,866	5,542	4,958	4,204	4,495
Depreciation	**(1,765)**	(1,611)	(1,485)	(1,375)	(1,328)
EBIT	**101**	3,931	3,473	2,829	3,167
Interest expense and other	**(1,207)**	(1,107)	(951)	(891)	(882)
Income taxes	**(34)**	(831)	(611)	(466)	(575)
Net (loss)/income	**(1,140)**	1,993	1,911	1,472	1,710
Net income attributable to non-controlling interests	**(6)**	(153)	(125)	(118)	(129)
Net (loss)/income attributable to controlling interests	**(1,146)**	1,840	1,786	1,354	1,581
Preferred share dividends	**(94)**	(97)	(74)	(55)	(55)
Net (loss)/income attributable to common shares	**(1,240)**	1,743	1,712	1,299	1,526
Comparable earnings	**1,755**	1,715	1,584	1,330	1,559
Comparable EBITDA	**5,908**	5,521	4,859	4,245	4,544
Cash Flow Statement					
Funds generated from operations	**4,513**	4,268	4,000	3,284	3,451
(Increase)/Decrease in operating working capital	**(398)**	(189)	(326)	287	235
Net cash provided by operations	**4,115**	4,079	3,674	3,571	3,686
Comparable distributable cash flow	**3,546**	3,406	3,234	2,589	2,966
Capital spending – capital expenditures	**3,918**	3,489	4,264	2,595	2,513
Capital spending – projects in development	**511**	848	488	3	16
Acquisitions, net of cash acquired	**236**	241	216	214	—
Cash dividends paid on common and preferred shares	**1,538**	1,439	1,356	1,281	1,016
Balance Sheet					
Assets					
Plant, property and equipment	**44,817**	41,774	37,606	33,713	32,467
Total assets	**64,483**	58,525	53,898	48,396	47,338
Capitalization					
Long-term debt	**31,584**	24,757	22,865	18,913	18,659
Junior subordinated notes	**2,422**	1,160	1,063	994	1,016
Preferred shares	**2,499**	2,255	1,813	1,224	1,224
Common shareholders' equity	**13,939**	16,815	16,712	15,687	15,570

	2015	2014	2013	2012	2011
Per Common Share Data					
Net income – basic	**($1.75)**	$2.46	$2.42	$1.84	$2.17
– diluted	**($1.75)**	$2.46	$2.42	$1.84	$2.17
Comparable earnings per share	**$2.48**	$2.42	$2.24	$1.89	$2.22
Dividends declared	**$2.08**	$1.92	$1.84	$1.76	$1.68
Book Value[1,2]	**$19.84**	$23.73	$23.62	$22.24	$22.12
Market Price					
Toronto Stock Exchange (dollars)					
High	**59.50**	63.86	51.21	47.44	44.74
Low	**40.58**	47.14	43.94	40.34	36.1
Close	**45.19**	57.10	48.54	47.02	44.53
Volume (millions of shares)	**372.6**	337.2	295.9	319.2	420.8
New York Stock Exchange (U.S. dollars)					
High	**49.64**	58.40	49.65	47.78	45.09
Low	**29.89**	42.21	42.39	39.74	36.12
Close	**32.59**	49.10	45.66	47.32	43.67
Volume (millions of shares)	**272.3**	249.0	129.7	109.0	154.2
Common shares outstanding (millions)					
Average for the year	**708.6**	708.0	706.7	704.6	701.6
End of year	**702.6**	708.7	707.4	705.5	703.9
Registered common shareholders[1]	**29,367**	30,513	31,300	31,449	32,113
Per Preferred Share Data (dollars)					
Dividends declared:					
Series 1, 2, 3, 4, 5, 7, 9, and 11 cumulative first preferred shares[3]	**$6.31**	$5.34	$4.16	$3.25	$3.25
Financial Ratios					
Dividend yield[4,5]	**4.6 %**	3.4%	3.8%	3.7%	3.8%
Price/earnings multiple[5,6]	**(25.8)**	23.2	20.1	25.5	20.5
Price/book multiple[2,5]	**2.3**	2.4	2.1	2.1	2.0
Debt to debt plus shareholders' equity[7]	**71 %**	61%	59%	56%	56%
Total shareholder return[8]	**(17.7)%**	22.0%	7.2%	9.9%	22.2%
Earnings to fixed charges[9]	**0.2**	2.8	2.8	2.2	2.6

1 As at December 31.

2 The price/book multiple is determined by dividing price per common share by book value per common share as calculated by dividing common shareholders' equity by the number of common shares outstanding as at December 31.

3

Cumulative First Preferred Shares	Issue Date	Annual Dividend Per Share	First quarterly dividend paid
Series 1	September 2009	$0.82	December 2009
Series 2 - upon conversion of Series 1	December 2014	$0.63	March 2015
Series 3	March 2010	$0.77	June 2010
Series 4 - upon conversion of Series 3	June 2015	$0.23	September 2015
Series 5	June 2010	$1.10	November 2010
Series 7	March 2013	$1.00	April 2013
Series 9	January 2014	$1.06	January 2014
Series 11	March 2015	$0.70	May 2015

4 The dividend yield is determined by dividing dividends per common share declared during the year by price per common share as at December 31.

5 Price per common share refers to market price per share as reported on the Toronto Stock Exchange as at December 31.

6 The price/earnings multiple is determined by dividing price per common share by the basic net income per share.

7 Debt includes Junior Subordinated Notes, total long-term debt, including the current portion of long-term debt, plus preferred securities as at December 31 and excludes long-term debt of joint ventures. Shareholders' equity in this ratio is as at December 31.

8 Total shareholder return is the sum of the change in price per common share plus the dividends received plus the impact of dividend re-investment in a calendar year, expressed as a percentage of the value of shares at the end of the previous year.

9 The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of EBIT and interest income and other, less income attributable to non-controlling interests with interest expense and undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of interest expense, and capitalized interest.

Investor information

STOCK EXCHANGES, SECURITIES AND SYMBOLS

TransCanada Corporation

Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

First Preferred Shares, Series 1 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.A

First Preferred Shares, Series 2 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.F

First Preferred Shares, Series 3 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.B

First Preferred Shares, Series 4 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.H

First Preferred Shares, Series 5 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.C

First Preferred Shares, Series 7 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.D

First Preferred Shares, Series 9 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.E

First Preferred Shares, Series 11 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.G

Annual Meeting The annual and special meeting of shareholders is scheduled for April 29, 2016 at 10:00 a.m. (Mountain Daylight Time) at the Markin McPhail Centre, at the at the Calgary Olympic Park, 88 Canada Olympic Road S.W., Calgary, Alberta.

Dividend Payment Dates Scheduled common share dividend payment dates in 2016 are January 29, April 29, July 29 and October 31.

For information on dividend payment dates for TransCanada Corporation and TCPL Preferred Shares visit our website at www.transcanada.com.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan (Plan) allows common and preferred shareholders of TransCanada and preferred shareholders of TCPL to purchase common shares of TransCanada by reinvesting their cash dividends without incurring brokerage or administrative fees. Participants in the Plan may also buy additional common shares, up to Cdn$10,000 per quarter. For more information on the Plan please contact our Plan agent, Computershare Trust Company of Canada or visit our website at www.transcanada.com.

TRANSFER AGENTS, REGISTRARS AND TRUSTEE

TransCanada Corporation Common Shares Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver) and Computershare Trust Company, N.A. (Golden)

TransCanada Corporation First Preferred Shares, Series 1, 2, 3, 4, 5, 7, 9 and 11 Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver)

TCPL Debentures

Canadian Series: BNY Trust Company of Canada (Halifax, Montréal, Toronto, Calgary and Vancouver)

10.5% series P	11.80% series U	9.80% series V	9.45% series W

U.S. Series: The Bank of New York (New York) 9.875%

TCPL Canadian Medium-Term Notes CIBC Mellon Trust Company (Montréal and Toronto)

TCPL U.S. Medium-Term Notes and Senior Notes The Bank of New York Mellon (New York)

TCPL U.S. Junior Subordinated Notes 2007 Computershare Trust Company, N.A. (Jersey City, NJ)

TCPL Junior Subordinated Notes 2015 Computershare Trust Company of Canada

NOVA Gas Transmission Ltd. (NGTL) Debentures

Canadian Series: BNY Trust Company of Canada (Montreal and Toronto)

12.20% series 20	12.20% series 21	9.90% series 23

U.S. Series: U.S. Bank Trust National Association (New York) 7.875%

NGTL Canadian Medium-Term Notes BNY Trust Company of Canada (Montreal and Toronto)

NGTL U.S. Medium-Term Notes U.S. Bank Trust National Association (New York)

REGULATORY FILINGS

Annual Information Form TransCanada's 2015 Annual information form, as filed with Canadian securities commissions and as filed under Form 40-F with the SEC, is available on our website at www.transcanada.com.

A printed copy may be obtained from:

Corporate Secretary, TransCanada Corporation, 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1

Shareholder assistance

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone or e-mail at:

Computershare Trust Company of Canada, 100 University Avenue, 8th Floor, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1.800.340.5024
Telephone: 1.514.982.7959

E-mail: transcanada@computershare.com

www.computershare.com

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

If you would like to receive quarterly reports, please contact Computershare or visit our website at www.transcanada.com.

Electronic Proxy Voting and Delivery of Documents TransCanada is using Notice & Access which allows an issuer to deliver the Management information circular to registered shareholders by posting it and other related materials on SEDAR at www.sedar.com and www.transcanada/notice-and-access.com. Registered shareholders who still wish to receive a paper copy of the Management information circular may request one free of charge by following the instructions set out in the notice that will be sent to all registered shareholders by mail. TransCanada is pleased to offer all shareholders the ability to receive their documents (annual report, management information circular, notice of meeting and view-only proxy form or voting instruction form) and vote online.

In 2016, registered shareholders who opt to receive their documents electronically will have a tree planted on their behalf through eTree. For more information and to sign up online, registered shareholders can visit www.investorcentre.com.

Shareholders who do not have access to e-mail, or who still prefer to receive their proxy materials by mail also have the ability to choose whether to receive TransCanada's annual report by regular mail. Each year, shareholders are required to renew their option and will receive a notification for doing so. The annual report is available on the TransCanada website at www.transcanada.com at the same time that the report is mailed to shareholders.

Notice and Access, electronic delivery and the ability to opt out of receiving the annual report by mail, provides increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the company.

TransCanada in the Community TransCanada's annual Corporate Responsibility Report is available at www.transcanada.com. If you would like to receive a copy of this report by mail, please contact:

Communications 450 1st Street SW, Calgary, Alberta T2P 5H1, 1.403.920.2000 or 1.800.661.3805 or Communications@transcanada.com

Visit our website at www.transcanada.com to access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call webcasts and investor presentations.

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site web ou vous adresser par écrit à TransCanada Corporation, bureau du secrétaire.

Board of directors

(as at December 31, 2015)

S. Barry Jackson[1,2]
Chairman
TransCanada Corporation
Calgary, Alberta

Russell K. Girling
President and CEO
TransCanada Corporation
Calgary, Alberta

Kevin E. Benson[1,4]
Corporate Director
Calgary, Alberta

Derek H. Burney, O.C.[4,7]
Senior Strategic Advisor
Norton Rose Canada LLP
Ottawa, Ontario

The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C.[2,5]
Senior Partner
Stein Monast L.L.P.
Québec, Québec

John E. Lowe[4,5]
Chairman
Apache Corporation
Houston, Texas

Paula Rosput Reynolds[5,8]
President and CEO
PreferWest LLC
Seattle, Washington

John Richels[2,5]
Corporate Director
Toronto, Ontario

Mary Pat Salomone[4,5]
Corporate Director
Naples, FL

D. Michael G. Stewart[4,6]
Corporate Director
Calgary, Alberta

Siim A. Vanaselja[1,3]
Corporate Director
Westmount, Québec

Richard E. Waugh[1,2]
Corporate Director
Toronto, Ontario

1 Member, Governance Committee
2 Member, Human Resources Committee
3 Chair, Audit Committee
4 Member, Audit Committee
5 Member, Health, Safety & Environment Committee
6 Chair, Health, Safety & Environment Committee
7 Chair, Governance Committee
8 Chair, Human Resources Committee

Corporate governance

Please refer to TransCanada's Notice of 2016 annual and special meeting of shareholders and Management information circular for the company's statement of corporate governance.

TransCanada's Corporate Governance Guidelines, Board charter, Committee charters, Chair and Chief Executive Officer terms of reference and code of business ethics are available on our website at www.transcanada.com. Also available on our website is a summary of the significant ways in which TransCanada's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Additional information relating to the company is filed with securities regulators in Canada on SEDAR (www.sedar.com) and in the United States on EDGAR (www.sec.gov). The documents referred to in this Annual Report may be obtained free of charge by contacting TransCanada's Corporate Secretary at 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1, or by calling 1.800.661.3805.

Ethics Help-Line The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1.888.920.2042.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TransCanada Corporation

We consent to the use of our reports, each dated February 10, 2016, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this annual report on Form 40-F.

We also consent to the incorporation by reference of such reports in TransCanada Corporation's:

- Registration Statements No. 333-5916, No. 333-8470, No. 333-9130, No. 333-151736 and No. 333-184074 on Form S-8;

- Registration Statements No. 33-13564 and No. 333-6132 on Form F-3; and,

- Registration Statements No. 333-151781, No. 333-161929, and No. 333-208585 on Form F-10.

/s/ KPMG LLP
Chartered Professional Accountants

February 11, 2016

Calgary, Canada

Exhibit 31.1

Certifications

I, Russell K. Girling, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 11, 2016

/s/ RUSSELL K. GIRLING

Russell K. Girling

President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Donald R. Marchand, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.
5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 11, 2016

/s/ DONALD R. MARCHAND

Donald R. Marchand
Executive Vice-President, Corporate Development and Chief Financial Officer

Exhibit 32.1

TRANSCANADA CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Russell K. Girling, the Chief Executive Officer of TransCanada Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's Annual Report as filed on Form 40-F for the fiscal year ending December 31, 2015 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RUSSELL K. GIRLING

Russell K. Girling
Chief Executive Officer
February 11, 2016

Exhibit 32.2

TRANSCANADA CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Donald R. Marchand, the Chief Financial Officer of TransCanada Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's Annual Report as filed on Form 40-F for the fiscal year ending December 31, 2015 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DONALD R. MARCHAND

Donald R. Marchand
Chief Financial Officer
February 11, 2016