TRANSCANADA CORP
Form 40-F
February 21, 2014

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U.S. Securities and Exchange Commission

Washington, D.C. 20549

Form 40-F

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

OR

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

For the fiscal year ended **December 31, 2013** Commission File Number **1-31690**

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada
(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., 717 Texas Street,
Houston, Texas, 77002-2761; (832) 320-5201
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities 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 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:

ý Annual Information Form ý 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, 2013, 707,441,314 common shares;
22,000,000 Cumulative Redeemable First Preferred Shares, Series 1;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 3;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5; and
24,000,000 Cumulative Redeemable First Preferred Shares, Series 7
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 ý No o

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 ý No o

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	333-192561

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

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Corporation 2013 Annual report 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 97 through 164 of the TransCanada Corporation 2013 Annual report to shareholders included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 1 through 96 of the TransCanada Corporation 2013 Annual report 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 "Report of management" that accompanies the audited consolidated financial statements on page 97 of the TransCanada Corporation 2013 Annual report 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

For information on disclosure controls and procedures, see "Other information Controls and procedures" in Management's discussion and analysis on page 82 of the TransCanada Corporation 2013 Annual report 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. Kevin E. Benson and Mr. Richard E. Waugh 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. Benson and Mr. Waugh as audit committee financial experts does not make Mr. Benson or Mr. Waugh an "expert" for any purpose, impose any duties, obligations or liability on Mr. Benson or Mr. Waugh 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 2013 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 pages 38 and 39 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 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 72 of the TransCanada Corporation 2013 Annual report to shareholders.

IDENTIFICATION OF THE AUDIT COMMITTEE

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

Chair:	K.E. Benson
Members:	D.H. Burney
	M. P. Salomone
	D.M.G. Stewart
	R. E. Waugh

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 impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities

- expected industry, market and economic conditions.

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

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 pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of our counterparties
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors

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

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the 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 and Chief Financial Officer

Date: February 21, 2014

DOCUMENTS FILED AS PART OF THIS REPORT

13.1	TransCanada Corporation Annual information form for the year ended December 31, 2013.
13.2	Management's discussion and analysis (included on pages 1 through 96 of the TransCanada Corporation 2013 Annual report to shareholders).
13.3	2013 Audited consolidated financial statements (included on pages 97 through 164 of the TransCanada Corporation 2013 Annual report 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, 2013.
EXHIBITS	
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

2013 Annual information form

February 19, 2014

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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, 2013 (**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 19, 2014 (**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 generally accepted accounting principles (**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 our business 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 contained or incorporated by reference in this AIF may include information about the following, among other things:

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

- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

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 pipelines business

the availability and price of energy commodities

the amount of capacity payments and revenues we receive from our energy business

regulatory decisions and outcomes

outcomes of legal proceedings, including arbitration

performance of our counterparties

changes in the political environment

changes in environmental and other laws and regulations

competitive factors in the pipeline and energy sectors

construction and completion of capital projects

costs for labour, equipment and materials

access to capital markets

interest and foreign exchange rates

weather

cyber security

technological developments

economic conditions in North America as well as globally.

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

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

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. 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 or revenues that exceeded 10 per cent of the total consolidated revenues of TransCanada as at Year End. TransCanada beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares in each of these subsidiaries, with the exception of TransCanada Keystone Pipeline, LP in which TransCanada indirectly holds 100 per cent of the partnership interests.

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*, *Oil Pipelines* and *Energy*. Natural Gas Pipelines and Oil Pipelines are principally comprised of our respective natural gas and oil 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, Oil 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 2014.

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Canadian Pipelines

Date	Description of development
NGTL System (formerly known as the Alberta System) and expansion projects	
January 2011	We received approval from the National Energy Board (**NEB**) to construct the Horn River pipeline.
March 2011	We commenced construction of the $275 million Horn River pipeline. We also executed an agreement to extend the Horn River pipeline by approximately 100 kilometres (km) (62 mile). An application requesting approval to construct and operate this extension was filed with the NEB in October 2011.
August 2011	The NEB approved construction of a 24 km (15 mile) extension of the Groundbirch pipeline and construction commenced.
October 2011	Commercial integration of the NGTL System and ATCO Pipelines (**ATCO**) system commenced. Under an agreement, the facilities of the NGTL System and ATCO system are commercially operated as a single transmission system and transportation service is provided to customers by us pursuant to the NGTL System's tariff and suite of rates and services. The agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of the NGTL System and ATCO system.
October 2011	The NEB approved the construction of natural gas pipeline projects for the NGTL System.
November December 2011	The regulatory decisions by which commercial integration of the NGTL System and ATCO system was authorized were the subject of appeals to the Federal Court of Appeal. We continued to work with ATCO to gather information for the final stage of the integration which is to swap assets of equal value and will require approval by both the Alberta Utilities Commission and the NEB.
May 2012	The Horn River project was completed, extending the NGTL System into the Horn River shale play in British Columbia (**B.C.**). The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 million cubic feet per day (**MMcf/d**) by 2020.
June 2012	The NEB approved the Leismer-Kettle River Crossover project, a 77 km (46 mile) pipeline to expand the NGTL System with the intent of increasing capacity to meet demand in northeastern Alberta. The expected cost of the expansion is $160 million.
December 2012	The current settlements for the NGTL System expired. Final tolls for 2013 were to be determined through either new settlements or rate cases and any orders resulting from the NEB's decision on the Canadian Restructuring Proposal.
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.
August 2013	We signed agreements for approximately two billion cubic feet per day (**Bcf/d**) of 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. (the **North Montney project**). The proposed North Montney project will include an interconnection with our proposed PRGT (as defined below) project to provide natural gas supply to the proposed Pacific NorthWest LNG export facility near Prince Rupert, B.C. and is expected to cost approximately $1.7 billion, which includes $100 million for downstream facilities. Under commercial arrangements, receipt volumes are expected to increase between 2016 and 2019 to an aggregate volume of approximately two Bcf/d and delivery volumes to the PRGT project are expected to be approximately 2.1 Bcf/d beginning in 2019. We also entered into arrangements with other parties for

	transportation services that will utilize the North Montney project facilities.
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 return at 10.1 per cent on a 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	We filed an application with the NEB to construct and operate the North Montney project. The estimated capital cost of the project is $1.7 billion and it consists of approximately 300 km (186 mile) of pipeline.
November 2013	The NEB approved the NGTL 2013-2014 Settlement and final 2013 rates, as filed, in November 2013. We expect the final tolls for 2014 for the NGTL System will be determined on the basis of the NGTL settlement process.

Date	Description of development
Canadian Mainline	
January February 2011	We received approval for revised interim tolls, effective March 1, 2011 which increased interim tolls from the current interim tolls which were based on 2010 final tolls, to more closely align with tolls calculated in accordance with the 2007-2011 settlement with stakeholders.
September 2011	To respond to the evolving changes in flow patterns on the Canadian Mainline, we developed a comprehensive business and services restructuring proposal. The Canadian Restructuring Proposal application with the NEB culminated from extensive discussion and negotiation with our shippers. The NEB established interim tolls for 2012 based on the approved 2011 final tolls.
November December 2011	We filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as then approved 2011 final tolls. The NEB approved our application for 2011 final tolls for the Canadian Mainline at the level of the tolls that were being charged on an interim basis. Final 2011 tolls were calculated in accordance with previously approved toll methodologies and were based on the principles contained in the 2007-2011 settlement with stakeholders, with adjustments to reduce toll impacts. Certain aspects of the 2011 revenue requirement were rolled into the Canadian Restructuring Proposal.
May 2012	We received NEB approval to build new pipeline facilities to provide Ontario and Quebec markets with additional gas supplies from the Marcellus shale basin.
May 2012	The additional open season for firm transportation service on the Canadian Mainline, to bring additional Marcellus shale gas into Canada, closed. We were able to accommodate an additional 50 MMcf/d from the Niagara meter station to Kirkwall, Ontario, effective November 2012.
November 2012	Transportation of natural gas supply from the Marcellus shale basin supply began moving on the Canadian Mainline.
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.
May 2013	We filed a compliance filing and an application for a review and variance of the NEB decision regarding the Canadian Restructuring Proposal.
June 2013	The NEB dismissed the review and variance application and set out a process to consider the tariff revisions. Additional changes to the Canadian Mainline's tariff were considered by the NEB as a separate application which was heard in an oral hearing.
July 2013	The NEB released its reasons for the dismissal. We began implementation of the NEB decision related to the Canadian Restructuring Proposal. Since implementation, an additional 1.3 Bcf/d of firm service originating at Empress, Alberta has been contracted for, more than doubling the contracted capacity of this location. 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 entered into a settlement (**LDC Settlement**) which was filed with the NEB for approval in December 2013. The LDC Settlement, if approved, will establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculates tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also includes an incentive mechanism that requires a $20 million (after tax) annual contribution by us from 2015 to 2020, which could result in a range of ROE outcomes from 8.70 per cent to 11.50 per cent. The

	LDC Settlement will enable the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement is 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 retains pricing flexibility for discretionary services and implements certain tariff changes and new services as required by the terms of the settlement. The NEB decision remains in effect pending the outcome of the LDC Settlement application.
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016. This represents a significant amount of volume renewal, especially by Canadian shippers.

Date	Description of development
U.S. Pipelines	
Gas Transmission Northwest LLC (GTN)	
May 2011	We closed the sale of a 25 per cent interest in each of GTN and Bison Pipeline LLC (**Bison**) to TC PipeLines, LP (**TCLP**) for a total transaction value of US$605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
November 2011	The Federal Energy Regulatory Commission (**FERC**) approved a settlement agreement between GTN and its shippers for new transportation rates to be effective January 2012 through December 2015. This settlement also requires GTN to file for new rates that are to be effective January 2016.
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold a 28.9 per cent interest in and are the General Partner of, TCLP.
Bison	
January 2011	Bison pipeline was placed into commercial service.
May 2011	We closed the sale of a 25 per cent interest in each of GTN and Bison to TCLP for a total transaction value of US$605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold a 28.9 per cent interest in and are the General Partner of, TCLP.
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 includes a 17 month moratorium through March 2015 and requires us to have new rates in effect by January 1, 2018.
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 are approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also includes a three year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.
ANR Pipeline	
June 2012	The FERC issued orders approving ANR's sale of its offshore assets to a newly created wholly owned subsidiary, TC Offshore LLC (**the LLC**), allowing the LLC to operate these assets as a stand alone interstate pipeline.
August 2012	The FERC approved ANR Storage Company's settlement with its shippers.
November 2012	The LLC began commercial operations.

ANR Lebanon Lateral Reversal Project

October 2013	We concluded a successful binding open season. We have executed firm transportation contracts for 350 MMcf/d at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal project, which will entail modifications to existing facilities. The facility modifications are expected to be completed in the first quarter 2014. Contracted volumes will increase over the course of 2014 generating incremental earnings. The project will substantially increase our ability to receive gas on ANR's southeast mainstream from the Utica/Marcellus shale areas.

Mexican Pipelines

Topolobampo and Mazatlan Pipeline projects

November 2012	The CFE awarded us with the contract to build, own and operate the Topolobampo pipeline project. The Topolobampo project is a 530 km (329 mile), 30 inch pipeline with a capacity of 670 MMcf/d and an estimated cost of US$1 billion that will deliver gas from El Encino, Chihuahua and interconnects with third party pipelines in El Oro, Sinaloa to Topolobampo, Sinaloa.
November 2012	The CFE awarded us with the contract to build, own and operate the Mazatlan pipeline project, from El Oro to Mazatlan, Mexico. The Mazatlan project is a 413 km (257 mile), 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.
First Quarter 2014	Permitting and engineering activities are advancing as planned for these two northwest Mexico pipelines. Both projects are supported by 25 year contracts with the CFE and are expected to be in service mid to late 2016.

Date	Description of development
Tamazunchale Pipeline Extension project	
February 2012	We signed a contract with the CFE for the Tamazunchale Pipeline Extension project. Engineering, procurement and construction contracts were signed and construction related activities began.
First Quarter 2014	The construction of the US$500 million Tamazunchale Pipeline Extension project is proceeding although delays have occurred due to a significant number of archeological finds within the pipeline route. It is expected these findings and related alternative construction will move the project's scheduled in service date to second quarter 2014. As these types of findings are not uncommon in significant infrastructure projects in Mexico, contractual relief for such delays is provided. We continue to work with local, state and federal authorities to minimize and mitigate ground disturbance at the specific sites as well as to minimize impact to the scheduled in service date.
Guadalajara	
June 2011	The Guadalajara pipeline was completed. We and CFE agreed to add a US$60 million compressor station to the pipeline.
First Quarter 2013	The compressor station went into service.
LNG Pipeline Projects	
Coastal GasLink	
June 2012	We were selected to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion, 650km (404 mile) 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.
January 2014	We filed the Application for an Environmental Assessment Certificate with the B.C. Environmental Assessment Office (**BCEAO**). We are currently focused on community, landowner, government and First Nations engagement as the project advances through the regulatory process. The pipeline would be placed in service near the end of the decade, subject to a final investment decision to be made by LNG Canada after obtaining final regulatory approvals. We continue to advance this project and all costs would be recoverable should the project not proceed.
Prince Rupert Gas Transmission Project (PRGT)	
January 2013	We were selected to design, build, own and operate the proposed $5 billion, 750 km (466 mile) PRGT. The proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St John, B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C. We are currently focused on First Nations, community, landowner and government engagement as the PRGT advances through the regulatory process with the BCEAO. We continue to refine our study corridor based on consultation and detailed studies to date. A final investment decision to construct the project, for a planned in service date of late 2018, is expected to be made following final regulatory approvals. We continue to advance this project and all costs would be fully recoverable should the project not proceed.
Alaska LNG Project	
March 2012	Three major producers (the **Alaska North Slope producers**), along with us through participation in the Alaska LNG Project, announced the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources through an LNG option. This would involve construction of a natural gas pipeline from the North Slope to Valdez, Alaska where the gas would be liquefied and shipped to international markets.

May 2012	We received approval from the State of Alaska to suspend and preserve our activities on the Alaska/Alberta route and focus on the LNG alternative. This allowed us to defer our obligation to file for a U.S. FERC certificate for the Alberta route beyond fall 2012, our original deadline.
July 2012	The Alaska LNG Project announced a non-binding public solicitation of interest in securing capacity on a potential new pipeline system to transport Alaska's North Slope gas. The solicitation of interest took place between August 2012 and September 2012. There were a number of non-binding expressions of interest from potential shippers from a broad range of industry sectors in North America and Asia.
January 2014	The State of Alaska is proposing new legislation that would transition from the *Alaska Gasline Inducement Act* and enable a new commercial arrangement to be established with us, the Alaska North Slope producers, and the Alaska Gasline Development Corp. It has also been agreed that an LNG export project, rather than a pipeline to Alberta, is the best opportunity to commercialize Alaska North Slope gas resources in current market conditions. It is anticipated that two years of front end engineering will be completed before further commitments to commercialize the project will be made.

Further information about developments in the Natural Gas Pipelines business can be found in the MD&A in the *About our business A long-term 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 OIL PIPELINES BUSINESS

Date	Description of development
Keystone Pipeline System	
January 2011	Required operational modifications were completed on the Canadian conversion section of the Keystone Pipeline System. As a result, the system was capable of operating at the approved design pressure.
February 2011	The commercial in service of the second section of Keystone extending the pipeline from Steele City Nebraska to Cushing, Oklahoma (the **Cushing Extension**) was achieved, and the Company also commenced recording earnings for the first section of Keystone, which delivers oil from Hardisty, Alberta to Wood River and Patoka in Illinois (**Wood River/Patoka**).
May 2011	Revised tolls came into effect for the Wood River/Patoka section.
Second Quarter 2011	The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration issued a corrective action order on Keystone as a result of two above ground incidents at pump stations in North Dakota and Kansas. We filed a restart plan with the U.S. Pipeline and Hazardous Material Safety Administration which was approved in June 2011.
February 2012	We announced that what had previously been the Cushing to U.S. Gulf Coast project of the Keystone Pipeline System has its own independent value to the marketplace, and that we plan to build it as the stand-alone pipeline which is not part of the Keystone XL Presidential Permit application.
May 2012	We filed revised fixed tolls for the Cushing Extension section of the Keystone Pipeline System with both the NEB and the FERC. The revised tolls, which reflect the final project costs of the Keystone Pipeline System, became effective July 1, 2012.
January 2014	We finished constructing the 780km (485 mile) 36 inch pipeline of the Gulf Coast project, the Keystone Pipeline System. Crude oil transportation service on the project began January 22, 2014. We are projecting an average pipeline capacity of 520,000 Bbl/d for the first year of operation.
Houston Lateral and Terminal	
Fourth Quarter 2013	Construction continued on the US$400 million 77 km (48 mile) Houston Lateral pipeline and tank terminal to transport crude oil to Houston, Texas refineries. We anticipate the capacity of the lateral will be similar to that of the Gulf Coast project and the terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in mid-2015.
Cushing Marketlink	
October 2012	We commenced construction on the Cushing Marketlink receipt facilities which will facilitate the transportation of crude oil from the market hub at Cushing to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System. Construction continues on the Cushing Marketlink receipt facilities at Cushing, Oklahoma, and is expected to be completed in the first half of 2014.
Keystone XL	
August 2011	We received a Final Environmental Impact Statement regarding the Keystone XL U.S. Presidential Permit application.
November 2011	The U.S. Department of State (**DOS**) announced that further analysis of route options for Keystone XL would need to be investigated, with a specific focus on the Sandhills area of Nebraska.

December 2011	We announced that we had received additional binding commitments in support of Keystone XL following the conclusion of the Keystone Houston Lateral open season, which commenced in August 2011.
February 2012	We sent a letter to the DOS informing the DOS that we planned to file a Presidential Permit application in near future for Keystone XL. We also informed the DOS that the Cushing to U.S. Gulf Coast portion of the Keystone XL project would be constructed outside of the Presidential Permit process.
May 2012	We filed a Presidential Permit application (cross-border permit) with the DOS for Keystone XL to transport crude oil from the U.S./Canada border in Montana to Steele City, Nebraska. We continued to work with the Nebraska Department of Environmental Quality (**NDEQ**) and various other stakeholders throughout 2012 to determine an alternative route in Nebraska that would avoid the Nebraska Sandhills. We proposed an alternative route to the NDEQ in April 2012, and then modified the route in response to comments from the NDEQ and other stakeholders.
September 2012	We submitted a Supplemental Environmental Report to the NDEQ for the proposed reroute for Keystone XL in Nebraska, and provided an environmental report to the DOS, required as part of the DOS review of our cross-border permit application.
January 2013	The 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.

Date	Description of development
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 Keystone XL. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is unlikely to significantly impact the rate of extraction in the oil sands and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas (**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, has the authority to approve an alternative route through Nebraska for the Keystone XL project. We will now analyze the judgment and decide what next steps may be taken. Nebraska's Attorney General has filed an appeal. We anticipate the pipeline, which will extend from Hardisty, Alberta to Steele City, Nebraska, to be in service approximately two years following the receipt of the Presidential Permit. The US$5.4 billion cost estimate will increase depending on the timing and conditions of the permit. Any capital cost increase above the initial estimated capital cost, up to a specified amount, is shared between us and the shippers such that 75 per cent of the change in capital cost is reflected in the fixed payment received by us. Any capital cost increase above the specified amount is shared equally between us and the shippers. As of December 31, 2013, we have invested US$2.2 billion in the project.
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 we are 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 is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries in Québec in 2018 with service to New Brunswick to follow in late 2018. We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. We intend to file the necessary regulatory applications in mid 2014 for approvals to construct and operate the pipeline project and terminal facilities.
Northern Courier Pipeline	
August 2012	We announced that we were selected by Fort Hills Energy Limited Partnership (**FHELP**) to design, build, own and operate the proposed Northern Courier Pipeline. The pipeline system is fully subscribed under long-term contract to service the Fort Hills mine, which is jointly owned by Suncor Energy Inc. (**Suncor**) and two other companies.
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 announced that the FHELP is proceeding with the Fort Hills oil sands mining project and that it expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project is expected to cost $800 million and will transport bitumen and diluent between the Fort Hills mine site and Suncor's terminal located north of Fort McMurray, Alberta.
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. The projects will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton/Heartland, Alberta market to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. We anticipate the pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to be placed in service in 2016.
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.
Keystone Hardisty Terminal	
March 2012	We launched and concluded a binding open season to obtain commitments from interested parties for the Keystone Hardisty Terminal.
May 2012	We announced that we had secured binding long-term commitments of more than 500,000 Bbl/d for the Keystone Hardisty Terminal, and are expanding the proposed two million barrel project to a 2.6 million barrel terminal at Hardisty, Alberta, due to strong commercial support.
May 2013	We started construction on the Keystone Hardisty Terminal which we anticipate will have a storage capacity of up to 2.6 million barrels of crude oil. The $300 million crude oil terminal at Hardisty, Alberta is expected to be in service in 2016.

Date	**Description of development**
Grand Rapids Pipeline	
October 2012	We announced that we had entered into binding agreements with a partner to develop the Grand Rapids Pipeline in northern Alberta. Along with our partner, we will each own 50 per cent of the project and we will operate the system, which is expected to cost $3 billion. Our partner entered into a long-term commitment to ship crude oil and diluent on this pipeline system.
May 2013	We filed a permit application for the Grand Rapids Pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work. The dual pipeline system could transport up to 900,000Bbl/d of crude oil and 330,000Bbl/d of diluent. Subject to regulatory approvals, the system is expected to be placed in service in multiple stages, with initial crude oil service by mid-2015 and the complete system in service in the second half of 2017.

Further information about developments in the Oil Pipelines business can be found in the MD&A in the *About our business A long-term strategy, Oil Pipelines Results, Oil Pipelines Outlook, Oil Pipelines Understanding the Oil Pipelines business* and *Oil Pipelines Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

DEVELOPMENTS IN THE ENERGY BUSINESS

Date	Description of development
Ontario Solar	
December 2011	We agreed to buy nine Ontario solar generation facilities (combined capacity of 86 megawatt (**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 PPAs with the OPA.
June 2013	We completed the acquisition of the first facility for $55 million.
September 2013	We completed the acquisition of two solar facilities for $99 million.
December 2013	We completed the acquisition of a fourth solar facility for $62 million. We expect the acquisition of the remaining five facilities to close in 2014, subject to satisfactory completion of the related construction activities and regulatory approvals.
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 for $190 million subject to closing adjustments. The sale is expected to close in late first quarter 2014.
Bécancour	
June 2011	Hydro-Québec Distribution (**Hydro-Québec**) notified us it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2012. 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.
June 2012	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 2013.
June 2013	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.
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 continues 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. Final execution of this amendment is conditional on the pending approval by the Régie de l'énergie.
Sundance	
January 2011	The Sundance A Units 1 and 2 were subject to a force majeure claim by the operator.
February 2011	The operator informed us that it was not economic to replace or repair Sundance A Units 1 and 2, and that the Sundance A PPA should be terminated. We disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA. Throughout 2011, revenues and costs had been

	recorded as though the outages were interruptions of supply in accordance with the terms of the PPA.
July 2012	An arbitration panel decided that the Sundance A PPA should not be terminated and ordered the operator to rebuild Units 1 and 2. The panel also limited the operator's force majeure claim from November 20, 2011 until the units could reasonably be returned to service. The operator announced that it expected the units to be returned to service in the fall of 2013. Since we considered the outages to be an interruption of supply, we accrued $188 million in pretax income between December 2010 and March 2012. The outcome of the decision was that we received approximately $138 million of this amount. We recorded the $50 million difference as a pre-tax charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011. We did not record further revenue or costs from the PPA until the units were returned to service. The net book value of the Sundance A PPA recorded in Intangibles and Other Assets remained fully recoverable.
November 2012	An arbitration decision was reached with the arbitration panel granting partial force majeure relief to the operator with respect to Sundance B Unit 3, and we reduced our equity earnings by $11 million from the ASTC Power Partnership (**ASTC**) to reflect the amount that will not be recovered as result of the decision. In 2010, Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components and was subject to a force majeure claim by the operator. The ASTC, which holds the Sundance B PPA, disputed the claim under the binding dispute resolution process provided in the PPA because we did not believe the operator's claim met the test of force majeure. We therefore recorded equity earnings from our 50 per cent ownership interest in ASTC as though this event were a normal plant outage.
September 2013	Sundance A Unit 1 returned to service.
October 2013	Sundance A Unit 2 returned to service.

Date	Description of development
Bruce Power	
February 2011	The Bruce Power Refurbishment Implementation Agreement (the **BPRIA**) was amended to extend the suspension date for Bruce A contingent support payments from December 31, 2011 to June 1, 2012. Contingent support payments received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A was subject to spot prices effective June 1, 2012 until the restart of both Units 1 and 2 was complete. Bruce Power and the OPA had amended certain terms and conditions of the BPRIA in July 2009, which included: amendments to the Bruce B floor price mechanism, the removal of a support payment cap for Bruce A, an amendment to the capital cost-sharing mechanism, and addition of a provision for deemed generation payments to Bruce Power at the contracted prices under circumstances where generation from Bruce A and Bruce B is reduced due to system curtailments on the Independent Electricity System Operator controlled grid in Ontario. Under the original BPRIA, which was signed in 2005, Bruce A committed to refurbish and restart the then currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. Fuelling of both Unit 2 and Unit 1 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.
November 2011	Bruce Power commenced the West Shift Plus outage as part of the life extension strategy for Unit 3.
March 2012	Bruce Power received authorization from the Canadian Nuclear Safety Commission to power up the Unit 2 reactor.
May 2012	An incident occurred within the Unit 2 electrical generator on the non-nuclear side of the plant which delayed the synchronization of Unit 2 to the Ontario electrical grid. As a result, Bruce Power submitted a force majeure claim to the OPA.
June 2012	Bruce Power returned Unit 3 to service after completing the $300 million West Shift Plus life extension outage, which began in 2011. Unit 4 was expected to return to service in late first quarter 2013 after the completion of an expanded outage investment program that began in August 2012. These investments should allow Units 3 and 4 to produce low cost electricity until at least 2021.
August 2012	We confirmed that Bruce Power's force majeure claim to the OPA related to Unit 2 (**Bruce A**) had been accepted. The claim was the result of a May 2012 event that delayed the synchronization of this unit to the Ontario power grid. With the acceptance of the force majeure claim, Bruce Power continued to receive the contracted price for power generated from the operating units at Bruce A after July 1, 2012.
October 2012	Unit 1 and 2 were returned to service following the completion of the refurbishment. The incident in May 2012 within the Unit 2 electrical generator on the non-nuclear side of the plant had delayed returning the units to service. Bruce Power's force majeure claim to the OPA was accepted in August, and it continued to receive the contracted price for power generated during the force majeure period.
November 2012	Both Units 1 and 2 have operated at reduced output levels following their return to service, and Bruce Power took Unit 1 offline for an approximate one month maintenance outage. Bruce Power expects the availability percentages for Units 1 and 2 to increase over time, however, these units have not operated for an extended period of time and may experience slightly higher forced outage rates and reduced availability percentages in 2013. All that time, overall plant availability for Bruce A was expected to be approximately 90 per cent in 2013.
April 2013	Bruce Power announced that it had reached an agreement with the OPA 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 Unit 4 to operate until at least 2021.

January 2014	Cameco Corporation announced it had agreed to sell its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We are considering our option to increase our Bruce B ownership percentage.
Napanee	
December 2012	We signed a contract with the OPA to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. Currently, the project is on schedule and we expect to complete the permitting process in late 2014. 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.
Cartier Wind	
November 2011	The Montagne-Sèche project and phase one of the Gros-Morne wind farm were completed.
November 2012	We placed the second phase of the Gros-Morne wind farm project in service, completing the 590 MW, five phase Cartier Wind Project in Québec. All of the power produced by Cartier Wind is sold to Hydro-Québec under 20 year PPAs.

Date	Description of development
CrossAlta	
December 2012	We acquired the remaining 40 per cent interests in the Crossfield Gas Storage facility and CrossAlta Gas Storage & Services Ltd. (**CrossAlta**) marketing company from our partner for approximately $214 million cash, net of cash acquired. We now own and operate 100 per cent of the interests of CrossAlta. The acquisition added an additional 27 billion cubic feet of working gas storage capacity to our existing portfolio in Alberta.
Coolidge	
May 2011	Coolidge power generating station was completed and placed in-service.
U.S. Power	
Third and Fourth Quarters 2011	Spot prices for capacity sales in the New York Zone J market were negatively impacted by the manner in which the New York Independent System Operator (**NYISO**) applied pricing rules for a power plant that had recently began service in this market. We jointly filed two formal complaints with the FERC challenging how the NYISO applied its buy-side mitigation rules affecting bidding criteria associated with two new power plants that began service in the New York Zone J markets during the summer of 2011.
June 2012	The FERC addressed the first complaint, indicating it would take steps to increase transparency and accountability for future mitigation exemption tests (**MET**) and decisions.
September 2012	The FERC granted an order on the second complaint, directing the NYISO to retest the two new power plants as well as a transmission project currently under construction using an amended set of assumptions to more accurately perform the MET calculations, in accordance with existing rules and tariff provisions. The recalculation was completed in November 2012 and it was determined that one of the plants had been granted an exemption in error. That exemption was revoked and the plant is now required to offer its capacity at a floor price which has put upward pressure on capacity auction prices since December. The order was prospective only and has no impact on capacity prices for prior periods.
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 NYISO 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. We do not expect this change to impact Zone J capacity prices in 2014, however, this new assumption does have the potential to negatively affect these capacity prices in 2015 and 2016. Additionally, another recent FERC decision affecting future capacity auctions in New England Power Pool (**NEPOOL**) may potentially improve capacity price conditions in 2018 and beyond for our assets that are located in NEPOOL.

Further information about developments in the Energy business can be found in the MD&A in the *About our business A long-term 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, Oil Pipelines and Energy. At Year End and for the year then ended, Natural Gas Pipelines accounted for approximately 51 per cent of revenues and 47 per cent of our total assets, Oil Pipelines accounted for approximately 13 per cent of revenues and 25 per cent of our total assets' and Energy accounted for approximately 36 per cent of revenues and 25 per cent of our total assets. The following table shows our revenues from operations by segment, classified geographically, for the years ended December 31, 2013 and 2012.

Revenues from operations (millions of dollars)	**2013**	**2012**
Natural Gas Pipelines		
Canada Domestic	$2,718	$2,294
Canada Export[1]	598	751
United States	1,069	1,112
Mexico	112	107
	4,497	4,264
Oil Pipelines		
Canada Domestic		
Canada Export[1]	399	370
United States	725	669
	1,124	1,039
Energy[2]		
Canada Domestic	1,941	1,233
Canada Export[1]		
United States	1,235	1,471
	3,176	2,704
Total revenues[3]	$8,797	$8,007

(1) Exports include pipeline revenues attributable to deliveries to U.S. pipelines 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. We also have regulated natural gas storage facilities in Michigan.

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	24,522 km (15,237 miles)	Gathers and transports natural gas within Alberta and northeastern 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 to serve eastern Canada and the U.S. northeast markets	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%
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			100%
Pipeline	16,121 km (10,017 miles)	Transports natural gas from producing fields in Texas and Oklahoma, from offshore and onshore regions of the Gulf of Mexico and from the U.S. midcontinent, for delivery to the Gulf Coast region as well as Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	
Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TCLP	50.2%
GTN	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TCLP	50.2%
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	67%

		U.S. upper Midwest. We effectively own 67 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.9 per cent interest in TCLP	
Iroquois	666 km (414 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 another third-party system on the California/Mexico border. We effectively own 28.9 per cent of the system through our interest in TCLP	28.9%
Northern Border	2,265 km (1,407 miles)	Transports natural gas through the U.S. Midwest, and connects with Foothills near Monchy, Saskatchewan. We effectively own 14.5 per cent of the system through our 28.9 per cent interest in TCLP	14.5%
Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 28.9 per cent of the system through our interest in TCLP	28.9%

	Length	Description	Effective Ownership
Mexican pipelines			
Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi	100%
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%
Tamazunchale Pipeline Extension	235 km (146 miles)	To extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro and other parts of central Mexico	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%
In development			
Alaska LNG Pipeline	1,448 km* (900 miles)	To transport natural gas from Prudhoe Bay to LNG facilities in Nikiski, Alaska	
Coastal GasLink	650 km* (404 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	750 km* (466 miles)	To deliver natural gas from North Montney gas producing region at a NGTL interconnect near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
North Montney Mainline	306 km* (190 miles)	To deliver natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline	100%

* Pipe lengths are estimates as final route is still under design.

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.

OIL PIPELINES BUSINESS

Our existing crude oil pipeline infrastructure connects Alberta 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.

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

	Length	Description	Ownership
Oil pipelines			
Keystone Pipeline System (includes Gulf Coast project)	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, Cushing, Oklahoma, and to the U.S. Gulf Coast refining market	100%
Under construction			
Cushing Marketlink Receipt Facility	Crude oil receipt facilities	To facilitate the transportation of crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System	100%
Houston Lateral and Terminal	77 km (48 miles)	To transport crude oil from the Keystone Pipeline System to Houston, Texas	100%
Keystone Hardisty Terminal	Crude oil terminal	Crude oil terminal to be located at Hardisty, Alberta, providing western Canadian producers with new crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
In development			
Bakken Marketlink Receipt Facility	Crude oil receipt facilities	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%
Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland market region	50%
Keystone XL	1,897 km (1,179 miles)	Crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
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%
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	4,500 km (2,700 miles)		100%

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

REGULATION OF THE NATURAL GAS AND OIL PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

The Canadian Mainline, NGTL System and most of the other Canadian pipelines owned or operated by TransCanada (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 the Company's 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. The decision of the NEB in March 2013 in respect of the Canadian Mainline approved the 2011 revenue requirement as filed, approved tolls charged in 2012 as final with any variance between revenues and costs deferred for recovery in future years, and set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others. 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 Canadian Mainline* section above.

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 return on equity, and any incentive earnings.

Natural Gas Pipelines Projects

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

Oil Pipelines

The NEB regulates the terms and conditions of service, including rates, and the physical operation of the Canadian portion of the Keystone Pipeline System, including the Keystone Hardisty Terminal. NEB approval is also required for facility additions. 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.

Oil Pipelines Projects

The Northern Courier Pipeline and Grand Rapids Pipeline are being proposed and developed primarily under the regulatory regime administered by the AER and Alberta Environment and Sustainable Resource Development (**ESRD**). AER approval is required to construct and operate the pipelines and associated facilities. ESRD approval is required to construct and operate a tank terminal when the project involves the storage of more than 10,000 cubic meters (62,898 barrels) of petroleum products. Pre-application activities are currently underway.

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.

Oil Pipelines

The FERC also regulates the terms and conditions of service, including transportation rates, on the U.S. portion of the Keystone Pipeline System. Certain states in which Keystone Pipeline System has rights of way also regulate construction and siting of Keystone Pipeline System. The Keystone XL project remains subject to the DOS decision on TransCanada's Presidential Permit application.

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 U.S. power business 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 critically located, essential capacity.

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 A and B and Portlands Energy.

	Generating capacity (MW)	Type of fuel	Description	Location	Ownership
Canadian Power 8,070 MW of power generation capacity (including facilities in development)					
Western Power 2,636 MW of power supply in Alberta and the western U.S.					
Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
Cancarb[1]	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TransCanada facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
Coolidge[2]	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	PPA for entire output of facility	Hanna, Alberta	100%
Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
Sundance B PPA (Owned by ASTC[3])	353[3]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
Eastern Power 2,950 MW of power generation capacity (including facilities in development)					

Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
Cartier Wind	366[4]	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[4]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
Ontario Solar	36	solar	Four solar facilities	Southern Ontario	100%

	Generating capacity (MW)	Type of fuel	Description	Location	Ownership
Bruce Power 2,484 MW of power generation capacity through eight nuclear power units					
Bruce A	1,462[4]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
Bruce B	1,022[4]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%
U.S. Power 3,755 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%
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%
In development					
Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
Ontario Solar	50	solar	Acquisition of five remaining solar facilities from Canadian Solar in 2014	Southern Ontario and New Liskeard, Ontario	100%

(1)

As at December 31, 2013 both the Cancarb waste heat and thermal carbon black plant were classified as Assets Held for Sale. For further information, refer to the *Energy Significant Events* section of the MD&A which is incorporated by reference herein.

(2)

Located in Arizona, results reported in Canadian Power   Western Power.

(3)

We have a 50 per cent interest in ASTC, which has a PPA in place for 100 per cent of the production from the Sundance B power generating facilities.

(4)

Our share of power generation capacity.

We own or have the rights to power supply in Alberta and Arizona through three long-term PPAs, five 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 ASTC)	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 contract.

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

	Type of contract	With	Expires
Bécancour[1]	20-year PPA Steam sold to an industrial customer.	Hydro-Québec	2026
Cartier Wind	20-year PPA	Hydro-Québec	2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2025
Halton Hills	20-year Clean Energy Supply contract	OPA	2030
Portlands Energy	20-year Clean Energy Supply contract	OPA	2029
Ontario Solar[2]	20-year Feed-in Tariff (**FIT**) contracts	OPA	2033

(1) Power generation has been suspended since 2008.

(2)
We acquired four facilities in 2013 and expect to acquire the remaining five facilities in 2014.

Assets currently in development are as follows:

	Type of contract	With	Expires
Ontario Solar[1]	20-year FIT contracts	OPA	20 years from in-service date
Napanee	20-year Clean Energy Supply contract	OPA	20 years from in-service date

(1)
We acquired four facilities in 2013 and expect to acquire the remaining five facilities in 2014.

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 5,551 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	2,736
Western Canada (excluding Calgary)	531
Eastern Canada	287
Houston	569
U.S. Midwest	477
U.S. Northeast	437
U.S. Southeast/Gulf Coast (excluding Houston)	304
U.S. West Coast	81
Mexico and South America	129
Total	5,551

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

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

Our management system for HSE is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements and various 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 quarterly with comparison to previously set targets and takes into account incidents and highlights of performance during the relevant quarter, and reviews programs, plans and performance targets for subsequent years. It receives detailed reports on our operational risk management, including governance of these risks, operational performance and preventive maintenance, asset integrity, operational risk issues, personnel security and applicable legislative developments. The committee also receives updates on any specific areas of operational risk management review being conducted by management.

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 inspection and audit programs designed to keep all of our facilities 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. Since 2008, we have sustained year over year improvement in our safety performance. Overall, TransCanada's incident frequency rates in 2013 continued to be better than most industry benchmarks.

The safety and integrity of our existing and newly-developed infrastructure is also 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. Our safety record in 2013 continued to exceed industry benchmarks.

TransCanada routinely conducts emergency response exercises to help ensure effective coordination between the Company, local emergency responders, regulatory agencies and members of the public in the event of an emergency. It also facilitates improving our emergency preparedness and response program and procedures.

Social Policies

TransCanada has a number of policies, guiding principles and practices in place to help manage Aboriginal and other 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. 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 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.

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, Oil 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 it 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. In the opinion of TransCanada's management, such provisions do not currently restrict or alter TransCanada's ability to declare or pay dividends.

Holders of cumulative redeemable first preferred shares, series 1 (the **Series 1 preferred shares**) are entitled to receive fixed cumulative preferential cash dividends, at an annual rate of $1.15 per share, payable quarterly, as and when declared by the Board, for the initial period ending December 31, 2014. The dividend on the Series 1 preferred shares will reset on December 31, 2014 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.92 per cent. The holders of Series 1 preferred shares have the right to convert their shares into cumulative redeemable first preferred shares, series 2 (the **Series 2 preferred shares**) as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 3 (the **Series 3 preferred shares**) are entitled to receive fixed cumulative preferential cash dividends, at an annual rate of $1.00 per share, payable quarterly, as and when declared by the Board, for the initial period ending June 30, 2015. The dividend on the Series 3 preferred shares will reset on June 30, 2015 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.28 per cent. The holders of Series 3 preferred shares have the right to convert their shares into cumulative redeemable first preferred shares, series 4 (the **Series 4 preferred shares**) as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 5 (the **Series 5 preferred shares**) are entitled to receive fixed cumulative preferential cash dividends, at an annual rate of $1.10 per share, payable quarterly, as and when declared by the Board, for the initial period ending January 30, 2016. The dividend on the Series 5 preferred shares will reset on January 30, 2016 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.54 per cent. The holders of Series 5 preferred shares have the right to convert their shares into cumulative redeemable first preferred shares, series 6 (the **Series 6 preferred shares**) as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 7 (the **Series 7 preferred shares**) are entitled to receive fixed cumulative preferential cash dividends, at an annual rate of $1.00 per share, payable quarterly, as and when declared by the Board, for the initial period ending April 30, 2019. The dividend on the Series 7 preferred shares will reset on April 30, 2019 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 2.38 per cent. The holders of Series 7 preferred shares have the right to convert their shares into cumulative redeemable first preferred shares, series 8 (the **Series 8 preferred shares**) as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 9 (the **Series 9 preferred shares**) are entitled to receive fixed cumulative preferential cash dividends, at an annual rate of $1.0625 per share, payable quarterly, as and when declared by the Board, for the initial period ending October 30, 2019. The dividend on the Series 9 preferred shares will reset on October 30, 2019 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 2.35 per cent. The holders of Series 9 preferred shares have the right to convert their shares into cumulative redeemable first preferred shares, series 10 (the **Series 10 preferred shares**) as set out under the heading *First preferred shares* below.

The dividends declared on the our preferred shares during the past three completed financial years are set out in the following table:

	2013	**2012**	**2011**
Dividends declared on Series 1 preferred shares	$1.15	$1.15	$1.15
Dividends declared on Series 3 preferred shares	$1.00	$1.00	$1.00
Dividends declared on Series 5 preferred shares	$1.10	$1.10	$1.10
Dividends declared on Series 7 preferred shares(1)	$1.00		
Dividends declared on Series 9 preferred shares(2)			

(1) Issued March 4, 2013.

(2) Issued January 20, 2014.

The dividends declared per common share of TransCanada during the past three completed financial years are set out in the following table:

	2013	**2012**	**2011**
Dividends declared on common shares	$1.84	$1.76	$1.68

We increased the quarterly dividend on our outstanding common shares by four per cent to $0.48 per share for the quarter ending March 31, 2014 which equates to $1.92 per share on an annualized basis.

Description of capital structure

SHARE CAPITAL

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 707,441,314 were 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.

Preferred Shares	Issued and Outstanding	Convertible to
Series 1	22,000,000	22 million Series 2 preferred shares
Series 3	14,000,000	14 million Series 4 preferred shares
Series 5	14,000,000	14 million Series 6 preferred shares
Series 7	24,000,000	24 million Series 8 preferred shares
Series 9[1]	18,000,000	18 million Series 10 preferred shares

(1) Issued January 20, 2014.

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 and preferred shares of TCPL 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 stock based compensation plans that allow 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 plans 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 or as referred to below, 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 Series 1 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The Series 1 preferred shares are redeemable by TransCanada in whole or in part on December 31, 2014, and on December 31 in every fifth year thereafter, 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 1 preferred shares have the right to convert their shares into cumulative redeemable Series 2 preferred shares, subject to certain conditions, on December 31, 2014 and on December 31 in every fifth year thereafter. The holders of Series 2 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 and 1.92 per cent and have the right to convert their shares into Series 1 preferred shares, subject to certain conditions, on December 31, 2019 and on December 31 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1

preferred shares shall be entitled to receive $25.00 per Series 1 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 1 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 2 preferred shares are substantially the same as the Series 1 preferred shares. The Series 2 preferred shares are redeemable by TransCanada in whole or in part on any date after December 31, 2014, 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 December 31, 2019 and on December 31 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 3 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 3 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 3 preferred shares are redeemable by TransCanada in whole or in part on June 30, 2015, and on June 30 in every fifth year thereafter, 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 3 preferred shares have the right to convert their shares into cumulative redeemable Series 4 preferred shares, subject to certain conditions, on June 30, 2015 and on June 30 in every fifth year thereafter. The holders of Series 4 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 and 1.28 per cent and have the right to convert their shares into Series 3 preferred shares, subject to certain conditions, on June 30, 2020 and on June 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 3 preferred shares shall be entitled to receive $25.00 per Series 3 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 3 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 4 preferred shares are substantially the same as the Series 3 preferred shares. The Series 4 preferred shares are redeemable by TransCanada in whole or in part on any date after June 30, 2015, 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 June 30, 2020 and on June 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 5 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 5 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 5 preferred shares are redeemable by TransCanada in whole or in part on January 30, 2016, and on January 30 in every fifth year thereafter, 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 5 preferred shares have the right to convert their shares into cumulative redeemable Series 6 preferred shares, subject to certain conditions, on January 30, 2016 and on January 30 in every fifth year thereafter. The holders of Series 6 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 and 1.54 per cent and have the right to convert their shares into Series 5 preferred shares, subject to certain conditions, on January 30, 2021 and on January 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 5 preferred shares shall be entitled to receive $25.00 per Series 5 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 5 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 6 preferred shares are substantially the same as the Series 5 preferred shares. The Series 6 preferred shares are redeemable by TransCanada in whole or in part on any date after January 30, 2016, 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 January 30, 2021 and on January 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 7 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 7 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 7 preferred shares are redeemable by TransCanada in whole or in part on April 30, 2019, and on April 30 in every fifth year thereafter, 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 7 preferred shares have the right to convert their shares into cumulative redeemable Series 8 preferred shares, subject to certain conditions, on April 30, 2019 and on April 30 in every fifth year thereafter. The holders of Series 8 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 and 2.38 per cent and have the right to convert their shares into Series 8 preferred shares, subject to certain conditions, on April 30, 2024 and on April 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 7 preferred shares shall be entitled to receive $25.00 per Series 7 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 7 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 8 preferred shares are substantially the same as the Series 7 preferred shares. The Series 8 preferred shares are redeemable by TransCanada in whole or in part on any date after April 30, 2019, 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 April 30, 2024 and on April 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 9 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 9 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 9 preferred shares are redeemable by TransCanada in whole or in part on October 30, 2019, and on October 30 in every fifth year thereafter, 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 9 preferred shares have the right to convert their shares into cumulative redeemable Series 10 preferred shares, subject to certain conditions, on October 30, 2019 and on October 30 in every fifth year thereafter. The holders of Series 10 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 and 2.35 per cent and have the right to convert their shares into Series 9 preferred shares, subject to certain conditions, on October 30, 2024 and on October 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 9 preferred shares shall be entitled to receive $25.00 per Series 9 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 9 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 10 preferred shares are substantially the same as the Series 9 preferred shares. The Series 10 preferred shares are redeemable by TransCanada in whole or in part on any date after October 30, 2019, 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 October 30, 2024 and on October 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

Except as provided by the CBCA, the respective holders of the first preferred shares of each 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 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 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.

The following table sets out the current credit ratings assigned to those outstanding classes of securities of the Company and TCPL 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
Preferred shares	Pfd-2 (low)	Baa2	P-2
Commercial paper	R-1 (low)		A-2
Trending/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 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 and 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 interest and principal 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 interest and principal is considered acceptable, but it may be vulnerable to future events. The Pfd-2 (low) rating assigned to TCPL's and 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 applied to each rating classification from Aa through Caa, with 1 being the highest and 3 being the lowest. 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 considered upper medium grade and are subject to low credit risk. The Baa1 and Baa2 ratings assigned to TCPL's junior subordinated debt and preferred shares, respectively, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated debt ranking slightly 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 subject to moderate credit risk, are considered medium-grade, 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. As guarantor of a U.S. subsidiary's commercial paper program, TCPL has been assigned a commercial paper rating of 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; however, the capacity to meet all financial commitments remains satisfactory. The BBB and P-2 ratings assigned to TCPL's junior subordinated notes and TCPL's and TransCanada's preferred shares exhibits 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, 3, 5, 7 and 9 preferred shares have been listed for trading on the TSX since September 30, 2009, March 11, 2010, June 29, 2010, March 4, 2013 and January 20, 2014 under the symbols TRP.PR.A, TRP.PR.B, TRP.PR.C, TRP.PR.D, and TRP.PR.E, 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, 3, 5 and 7 preferred shares on the TSX, for the period indicated:

COMMON SHARES

	TSX (TRP)				NYSE (TRP)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**	**High (US$)**	**Low (US$)**	**Close (US$)**	**Volume Traded**
December 2013	$48.93	$46.10	$48.54	22,141,189	$46.02	$43.32	$45.66	10,823,386
November 2013	$48.48	$46.61	$46.85	25,329,959	$46.45	$44.17	$44.39	8,847,429
October 2013	$47.24	$43.94	$46.99	21,425,127	$45.25	$42.41	$45.11	