TRANSCANADA CORP
Form 40-F
February 13, 2013

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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, 2012** 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, 2012, 705,461,386 common shares;
22,000,000 Cumulative Redeemable First Preferred Shares, Series 1;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 3; and
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5
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 o 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	333-177788

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

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Corporation 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 158 of the TransCanada Corporation 2012 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 2012 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 2012 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 pages 77 and 78 of the TransCanada Corporation 2012 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 has been designated an audit committee financial expert and is 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 as an audit committee financial expert does not make Mr. Benson an "expert" for any purpose, impose any duties, obligations or liability on Mr. Benson 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 2012 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Corporate governance   Audit committee   Pre-approval policies and procedures" and "Corporate governance   Audit committee   External auditor service fees" on page 32 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 24 of the Notes to the Audited Consolidated Financial Statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on Tabular Disclosure of Contractual Obligations, see "Contractual Obligations" in Management's Discussion and Analysis on page 67 of the TransCanada Corporation 2012 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
	P.L. Joskow
	D.M.G. Stewart

FORWARD-LOOKING INFORMATION

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

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

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

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows
- 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 outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future commitments and contingent liabilities
- expected industry, market and economic conditions.

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

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

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of debt issuances 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 U.S. 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
- labour, equipment and material costs

- access to capital markets
- cybersecurity
- interest and foreign exchange rates
- weather
- 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).

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 13, 2013

DOCUMENTS FILED AS PART OF THIS REPORT

13.1	TransCanada Corporation Annual Information Form for the year ended December 31, 2012.
13.2	Management's Discussion and Analysis (included on pages 1 through 96 of the TransCanada Corporation 2012 Annual Report to Shareholders).
13.3	2012 Audited Consolidated Financial Statements (included on pages 97 through 158 of the TransCanada Corporation 2012 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, 2012.
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

2012 Annual information form

February 11, 2013

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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 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, 2012 (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 11, 2013 (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 (U.S. GAAP). Effective January 1, 2012, TransCanada adopted U.S. GAAP for reporting purposes. For more information regarding TransCanada's adoption of U.S. GAAP, refer to the *Other information Critical accounting policies and estimates* and *Other information Accounting changes* sections of the MD&A.

We use certain financial measures that do not have a standardized meaning under U.S. GAAP because we believe they improve our ability to compare results between reporting periods, and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies. 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 U.S. 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
- 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 outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future 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 debt issuances 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 U.S. 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
- labour, equipment and material costs
- access to capital markets
- cybersecurity

- interest and foreign exchange rates
- weather
- 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).

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 a plan of 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 and its subsidiaries. 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

Our reportable business segments are *Natural Gas Pipelines*, *Oil Pipelines* and *Energy*. Natural Gas Pipelines and Oil Pipelines are principally comprised of the Company's 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 the Company's power operations and the non-regulated natural gas storage business in Canada. Refer to the *Business of TransCanada* section below for further information regarding our Natural Gas Pipelines, Oil Pipelines and Energy businesses.

Summarized below are significant developments that have occurred in TransCanada's Natural Gas Pipelines, Oil Pipelines and Energy businesses, respectively, and the significant acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years.

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Date	Description of development
Canadian Mainline	
December 2010	TransCanada filed an application with the National Energy Board (NEB) for approval of the interim 2011 tolls for the Canadian Mainline which contained certain changes to the tolling mechanism to reduce long haul tolls. The NEB decided not to approve the tolls as requested in the interim tolls application and set the then current 2010 tolls as interim tolls commencing January 1, 2011.
January February 2011	TransCanada received approval for revised interim tolls, effective March 1, 2011 which increased interim tolls to more closely align with tolls calculated in accordance with the 2007-2011 settlement with stakeholders and more closely reflected the Canadian Mainline's costs and throughput for 2011.
September 2011	We filed a comprehensive restructuring proposal (Mainline Restructuring Proposal) with the NEB for the Canadian Mainline. The proposal is intended to enhance the competitiveness of the Canadian Mainline and transportation from the Western Canadian Sedimentary Basin (WCSB), and includes a request for 2012 and 2013 tolls that align with the proposed changes to our business structure and the terms and conditions of service on the Canadian Mainline. The NEB established interim tolls for 2012 based on the approved 2011 final tolls.
November December 2011	TransCanada 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 TransCanada's 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 Mainline Restructuring Proposal.
May 2012	We received NEB approval to build new pipeline facilities to provide Southern Ontario with additional natural gas supply 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 million cubic feet per day (MMcf/d) from the Niagara meter station to Kirkwall, Ontario, effective November 2012, with the potential for an additional 350 MMcf/d of incremental volume for November 2015, subject to finalizing precedent agreements with the interested parties.
June 2012	The NEB hearing on the Mainline Restructuring Proposal began and the hearing concluded in December 2012. A decision is not expected until late first quarter or early second quarter 2013.
November 2012	Natural gas supply from the Marcellus shale basin supply began moving in November 2012.
Alberta System	
February 2010	TransCanada filed an application with the NEB for approval to construct and operate the Horn River pipeline.
March 2010	The North Central Corridor expansion of the Alberta System was completed.
March 2010	After a public hearing, the NEB approved TransCanada's application after a public hearing to construct and operate the Groundbirch pipeline project.
June 2010	TransCanada reached a three year settlement agreement with the Alberta System shippers and other interested parties and filed a 2010-2012 Revenue Requirement Settlement Application with the NEB.

August 2010	The NEB approved TransCanada's November 2009 application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System.
September 2010	The NEB approved the Alberta System's 2010-2012 Revenue Requirement Settlement Application.
October 2010	The NEB approved final 2010 tolls for the Alberta System, which reflect the Alberta System 2010-2012 Revenue Requirement Settlement and Rate Design Settlement.
December 2010	The NEB approved the interim 2011 tolls for the Alberta System reflecting the 2010-2012 Revenue Requirement Settlement and continuing to transition to the toll methodology approved in the Rate Design Settlement.
December 2010	Groundbirch pipeline was completed and began transporting natural gas from the Montney shale gas formation into the Alberta System.
January 2011	TransCanada received approval from the NEB to construct the Horn River pipeline.
March 2011	TransCanada commenced construction of the $275 million Horn River pipeline. In addition, the Company executed an agreement to extend the Horn River pipeline by approximately 100 kilometers (km) (62 miles) at an estimated cost of $230 million. An application requesting approval to construct and operate this extension was filed with the NEB in October 2011. The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 MMcf/d by 2020.
August 2011	The NEB approved construction of a 24 km (15 mile) extension of the Groundbirch pipeline and construction commenced.

Date	Description of development
October 2011	Commercial integration of the Alberta System and ATCO Pipelines systems commenced. Under an agreement, the facilities of the Alberta System and ATCO Pipelines system are commercially operated as a single transmission system and transportation service is provided to customers by TransCanada pursuant to the Alberta 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 Alberta System and ATCO Pipelines system.
October 2011	The NEB approved the construction of natural gas pipeline projects for the Alberta System with a capital cost of approximately $910 million.
November December 2011	The regulatory decisions by which commercial integration of the Alberta System and ATCO Pipelines system was authorized are the subject of appeals to the Federal Court of Appeal. TransCanada continues 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 approximate $250 million Horn River project was completed, extending the Alberta System into the Horn River shale play in British Columbia (B.C.).
June 2012	The NEB approved the Leismer-Kettle River Crossover project, a 77 km (46 mile) pipeline to expand the Alberta System with the intent of increasing capacity to meet demand in northeastern Alberta. The expected cost of the expansion is an estimated $160 million.
Third Quarter 2012	During the first nine months of 2012, TransCanada continued to expand its Alberta System by completing and placing in-service twelve separate pipeline projects at a total cost of approximately $680 million.
December 2012	TransCanada was waiting for approval of approximately $330 million in additional projects, including the $100 million Chinchaga Expansion and the $230 million Komie North project that would extend the Alberta System further into the Horn River area.
December 2012	The current settlements for the Alberta and Foothills systems expired. Final tolls for 2013 will be determined through either new settlements or rate cases and any orders resulting from the NEB's decision on the Mainline 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. All applications awaiting approval as of the end of 2012 have now been addressed.
2013	We continue to advance pipeline development projects in B.C. and Alberta to transport new natural gas supply. We have filed applications with the NEB to expand the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. In addition, subject to regulatory approvals, we propose to extend the Alberta System in northeast B.C. to connect both to the Prince Rupert Gas Transmission Project (as described below) and to additional North Montney gas supplies. Initial capital cost estimates are approximately $1 billion to $1.5 billion, with an in-service date targeted for the end of 2015. We have incremental firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeastern B.C. by 2014.
Coastal GasLink	
June 2012	We were selected by Shell Canada Limited (Shell) and its partners to design, build, own and operate the proposed Coastal GasLink project, an estimated $4 billion pipeline. The liquefied natural gas (LNG) Canada project is a joint venture led by Shell, with partners Korea Gas Corporation, Mitsubishi Corporation and PetroChina Company Limited. The approximate 650 km (404 mile) pipeline is expected to have an initial capacity of more than 1.7 Bcf/d and be placed in-service toward the end of the decade, subject to a final investment decision to be made by LNG Canada subsequent to obtaining final regulatory approvals.

Prince Rupert Gas Transmission Project

January 2013	We were selected by Progress Energy Canada Ltd. (Progress) to, subject to regulatory approvals, design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission Project. This 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 expect to finalize definitive agreements in early 2013, leading to an in-service date in late 2018. A final investment decision to construct the project is expected to be made by Progress following final regulatory approvals.

Mexican Pipelines

June 2011	The Guadalajara pipeline was completed. TransCanada and Mexico's Comisión Federal de Electricidad (CFE) have agreed to add a US$60 million compressor station to the pipeline.
February 2012	We signed a contract with the CFE for the approximately $500 million Tamazunchale Pipeline Extension Project. The project, which is supported by a 25-year contract with CFE, is a 30 inch pipeline with a capacity of 630 MMcf/d. Engineering, procurement and construction contracts have all been signed and construction related activities have begun. We expect the pipeline to be in-service in the first quarter of 2014.
November 2012	The CFE awarded us the Topolobampo pipeline. The project, which is supported by a 25-year contract with CFE, is a 30 inch pipeline with a capacity of 670 MMcf/d. We estimate total costs to be US$1 billion, and expect it to be in-service in mid-2016.
November 2012	The CFE awarded us the Mazatlan pipeline, from El Oro to Mazatlan, Mexico. The project, which is supported by a 25-year contract with CFE and interconnects with the Topolobampo project, is a 24 inch pipeline with a capacity of 200 MMcf/d. We estimate total costs to be US$400 million, and expect it to be in-service in 2016.

Date	Description of development
Alaska Pipeline Project	
April 2010	The Alaska Pipeline open season commenced.
Third Quarter 2010	Interested shippers on the proposed Alaska Pipeline Project submitted conditional commercial bids in the open season that closed in July 2010. The Alaska Pipeline Project team continued to work with shippers to resolve conditional bids received as part of the project's open season in working toward a U.S. Federal Energy Regulatory Commission (FERC) application deadline of October 2012 for the Alberta option that would extend from Prudhoe Bay to points near Fairbanks and Delta Junction, and then to the Alaska/Canada border where the pipeline would connect with a new pipeline in Canada.
March 2012	The Alaska North Slope producers (Exxon Mobil Corporation, ConocoPhillips and British Petroleum (BP)), along with TransCanada through its participation in the Alaska Pipeline 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 FERC certificate for the Alberta route beyond fall 2012, our original deadline.
July 2012	The Alaska Pipeline 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.
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, allowing TC Offshore 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	TC Offshore LLC began commercial operations.
Gas Transmission Northwest LLC (GTN)	
May 2011	TransCanada closed the sale of a 25 per cent interest in each of GTN and Bison Pipeline LLC (Bison) to TC PipeLines, LP for a total transaction value of $605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
November 2011	The 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.
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.

Great Lakes	
July 2010	The FERC approved, without modification, the settlement stipulation agreement reached among Great Lakes Gas Transmission Limited Partnership, active participants and the FERC trial staff. As approved, the stipulation and agreement applies to all current and future shippers on Great Lakes. This settlement requires Great Lakes to file for new rates by November 1, 2013.
Bison	
December 2010	Construction of Bison pipeline was completed.
January 2011	Bison pipeline was placed into commercial service.
May 2011	TransCanada closed the sale of a 25 per cent interest in each of GTN and Bison to TC PipeLines, LP for a total transaction value of $605 million, which included US$81 million or 25 percent of GTN's outstanding debt.

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
Gulf Coast Project	
February 2012	We announced that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Pipeline has its own independent value to the marketplace, and that we plan to build it as the stand-alone Gulf Coast Project, which is not part of the Keystone XL Presidential Permit process. We expect the 36-inch pipeline to have an initial capacity of up to 700,000 barrels per day (Bbl/d), and an ultimate capacity of 830,000 Bbl/d. We estimate the total cost of the project to be US$2.3 billion, and as of Year End, construction was approximately 35 per cent complete. US$300 million of the total cost is expected to be spent on the Houston Lateral pipeline, a 76 km (47 mile) pipeline that will transport crude oil to Houston refineries.
August 2012	Construction on the Gulf Coast Project commenced. We expect to place the pipeline in service at the end of 2013.
Keystone XL Pipeline	
March 2010	The NEB approved TransCanada's application to construct and operate the Canadian portion of the Keystone U.S. Gulf Coast expansion.
April 2010	The U.S. Department of State (DOS) issued a Draft Environmental Impact Statement for Keystone XL.
June 2010	Keystone XL commenced operating at a reduced maximum operating pressure as the first section began delivering oil from Hardisty, Alberta to Wood River and Patoka in Illinois (Wood River/Patoka).
December 2010	The reduced maximum operating pressure restriction on the Canadian conversion section of the Wood River/Patoka section of Keystone was removed by the NEB following the completion of in-line inspections.
Fourth Quarter 2010	Construction of the second section of Keystone extending the pipeline from Steele City, Nebraska to Cushing, Oklahoma (the Cushing Extension) was completed, and line fill commenced in late 2010.
January 2011	Required operational modifications were completed on the Canadian conversion section of Keystone. As a result, the system was capable of operating at the approved design pressure.
February 2011	The commercial in service of the Cushing Extension was achieved, and the Company also commenced recording earnings for the Wood River/Patoka section.
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. TransCanada filed a re-start plan with the U.S. Pipeline and Hazardous Material Safety Administration which was approved in June 2011.
August 2011	TransCanada received a Final Environmental Impact Statement regarding the Keystone XL U.S. Presidential Permit application.
November 2011	The 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	TransCanada announced that it 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	TransCanada sent a letter to the DOS informing the DOS that TransCanada planned to file a Presidential Permit application in near future for Keystone XL. TransCanada also informed the DOS that the Cushing to U.S. Gulf Coast portion of the Keystone XL project would be constructed as the Gulf Coast Project and not as part of the Presidential Permit process.
May 2012	TransCanada 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.
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 collaboratively 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 had 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	TransCanada submitted a Supplemental Environmental Report to the NDEQ for the proposed re-route 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 re-route of Keystone XL to the Governor of Nebraska. The report noted that the proposed re-route avoids the Nebraska Sandhills, and that construction and operation of Keystone XL is expected to have minimal environmental impacts in Nebraska. In January, the Governor of Nebraska approved our proposed re-route. The DOS is now completing their environmental and National Interest Determination review process and we are awaiting their decision on our cross-border permit application. We estimate the total cost of the project to be US$5.3 billion and, as of Year End, had invested US$1.8 billion. We expect the pipeline to be in-service in late 2014 or early 2015, subject to regulatory approvals.

Date	Description of development
Marketlink Projects	
November 2010	The open seasons for the Bakken Marketlink and Cushing Marketlink projects, which commenced in September 2010, closed successfully.
October 2012	We have commenced construction on the Cushing Marketlink receipt facilities and expect to begin transporting crude oil supply from the Permian Basin producing region in western Texas to the U.S. Gulf Coast in late 2013 after our Gulf Coast Project is placed in-service. Our Bakken Marketlink project will transport crude oil supply from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL which remains subject to regulatory approval.
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. We expect the terminal to be operational in late 2014 and cost approximately $275 million.
Northern Courier Pipeline	
August 2012	We announced that we had been selected by Fort Hills Energy Limited Partnership to design, build, own and operate the proposed Northern Courier Pipeline. We estimate total capital costs to be $660 million. The pipeline system is fully subscribed under long-term contract to service the Fort Hills mine, which is jointly owned by Suncor Energy Inc, Total E&P Canada Ltd. and Teck Resources Limited. The project is conditional on the Fort Hills project receiving sanctions by the owners of the Fort Hills mine and is subject to regulatory approval.
Grand Rapids Pipeline	
October 2012	We announced that we had entered into binding agreements with Phoenix Energy Holdings Limited (Phoenix) to develop the Grand Rapids Pipeline in northern Alberta. The project, which includes crude oil and diluent lines, will have the capacity to move up to 900,000 Bbl/d of crude oil and 330,000 Bbl/d of diluent. We and Phoenix will each own 50 per cent of the project and we will operate the system, which is expected to cost $3 billion. Phoenix has entered into a long-term commitment to ship crude oil and diluent on this pipeline. We expect the Grand Rapids Pipeline system, subject to regulatory approvals, to be placed in-service in multiple stages, with initial crude oil service by mid-2015 and the complete system in-service by the second half of 2017.
Canadian Mainline Conversion	
Third Quarter 2012	We have determined that it is technically and economically feasible to convert a portion of the Canadian Mainline natural gas pipeline system to crude oil service. We are actively pursuing this project and have begun soliciting input from stakeholders and prospective shippers to determine market acceptance.

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
Sundance	
Second Quarter 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 TransAlta Corporation (TransAlta). The ASTC Power Partnership, which holds the Sundance B power purchase agreement (PPA), disputed the claim under the binding dispute resolution process provided in the PPA because we did not believe TransAlta's claim met the test of force majeure. We therefore recorded equity earnings from our 50 per cent ownership interest in ASTC Power Partnership as though this event were a normal plant outage.
December 2010	Sundance A Units 1 and 2 were withdrawn from service.
January 2011	Sundance A Units 1 and 2 were subject to a force majeure claim by TransAlta.
February 2011	TransAlta informed us that it was not economic to replace or repair 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.
July 2012	An arbitration panel decided that the Sundance A PPA should not be terminated and ordered TransAlta to rebuild Units 1 and 2. The panel also limited TransAlta's force majeure claim from November 20, 2011 until the units can reasonably be returned to service. TransAlta announced that it expects 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 pre-tax 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 charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011. We will not record further revenue or costs from the PPA until the units are returned to service. The net book value of the Sundance A PPA recorded in Intangibles and Other Assets remains fully recoverable.
November 2012	An arbitration decision was reached with the arbitration panel granting partial force majeure relief to TransAlta with respect to Sundance B Unit, and we reduced our equity earnings by $11 million from the ASTC Power Partnership to reflect the amount that will not be recovered as result of the decision.
Napanee Generating Station	
December 2012	We signed a contract with the Ontario Power Authority (OPA), to develop, own and operate a new 900 megawatt (MW) natural gas-fired power plant at Ontario Power Generation's Lennox site in Eastern Ontario in the town of Greater Napanee. The plant will replace the facility that was planned and subsequently cancelled in the community of Oakville, Ontario and will operate under a 20-year Clean Energy Supply contract with the OPA. We were reimbursed for $250 million of costs, mainly related to natural gas turbines that were purchased for the Oakville project, which will now be used at Napanee. We plan to invest approximately $1.0 billion in the Napanee facility.
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 Distribution (Hydro-Québec) under 20-year PPAs.
Ontario Solar	

December 2011	We agreed to buy nine Ontario solar projects (combined capacity of 86 MW) from Canadian Solar Solutions Inc. (Canadian Solar), for approximately $476 million. Under the terms of the agreement, Canadian Solar will develop and build each of the nine solar projects using photovoltaic panels. We will buy each project once construction and acceptance testing are complete and commercial operation begins. All power produced will be sold under 20-year PPAs with the OPA under the Feed-in Tariff program in Ontario. We expect to close the acquisition of the first two projects (combined capacity of 20 MW) in the first half of 2013 for a total cost of approximately $125 million. We expect to acquire the other seven projects in 2013 to late 2014, subject to regulatory approvals.
Bécancour	
June 2011	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 has the option, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. We continue to receive capacity payments under the agreement similar to those that would have been received under the normal course of operation.
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. Under the suspension agreement, Hydro-Québec has the option (subject to certain conditions) to extend the suspension every year until regional electricity demand levels recover. We continue to receive capacity payments while generation is suspended.

Date	Description of development
Bruce	
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 is 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	TransCanada 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. Overall plant availability for Bruce A is expected to be approximately 90 per cent in 2013.
Ravenswood	
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.
CrossAlta	
December 2012	We acquired the remaining 40 per cent interests in the Crossfield Gas Storage facility and CrossAlta Gas Storage & Services Ltd. marketing company from BP for approximately $220 million. We now own and operate 100 per cent of the interests of CrossAlta. The acquisition added an additional 27 billion cubic feet (Bcf) of working gas storage capacity to our existing portfolio in Alberta.
Coolidge	
May 2011	Coolidge power generating station was completed and placed in-service.
Kibby Wind	
October 2010	The 22 turbine, 66 MW second phase of Kibby Wind was completed and placed in service.
Halton Hills	
September 2010	The 683 MW Halton Hills power plant was completed and placed in-service.

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 53 per cent of revenues and 48 per cent of TransCanada's total assets, Oil Pipelines accounted for approximately 13 per cent of revenues and 22 per cent of TransCanada's total assets and Energy accounted for approximately 34 per cent of revenues and 27 per cent of TransCanada's total assets. The following table shows TransCanada's revenues from operations by segment, classified geographically, for the years ended December 31, 2012 and 2011.

Revenues from operations (millions of dollars)	**2012**	**2011**
Natural Gas Pipelines		
Canada Domestic	$2,294	$2,180
Canada Export[1]	751	786
United States	1,112	1,207
Mexico	107	71
	4,264	4,244
Oil Pipelines		
Canada Domestic		
Canada Export[1]	370	300
United States	669	527
	1,039	827
Energy[2]		
Canada Domestic	1,233	1,749
Canada Export[1]		1
United States	1,471	1,018
	2,704	2,768
Total revenues[3]	$8,007	$7,839

(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

TransCanada delivers natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. Our Natural Gas Pipelines and related holdings are described below.

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

	Length	Description	Effective ownership
Canadian pipelines			
Alberta System	24,337 km (15,122 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	14,101 km (8,762 miles)	Transports natural gas from the Alberta/Saskatchewan border to the Québec/Vermont border, and connects with other natural gas pipelines in Canada and the U.S.	100%
Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%
Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montreal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
U.S. pipelines			
ANR Pipeline	16,656 km (10,350 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 mainly to Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	100%
ANR 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 83.3 per cent of the system through the combination of our 75 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	83.3%
GTN	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountain region to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 83.3 per cent of the system through the combination of our 75 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	83.3%
Great Lakes	3,404 km (2,115 miles)	Connects with ANR and the Canadian Mainline near Emerson, Manitoba, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 69.0 per cent of the system through the combination of our	69%

		53.6 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	
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 Ehrenberg, Arizona and Ogilby, California, and connects with a third-party natural gas system on the California/Mexico border. We effectively own 33.3 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	33.3%
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 16.7 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	16.7%
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 Wadsworth, Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 33.3 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP.	33.3%

	Length	Description	Effective ownership
Mexican pipelines			
Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo to Guadalajara in Mexico	100%
Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potos, Mexico	100%
Under construction			
Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Mexico. Connects to the Topolobampo Pipeline Project	100%
Tamazunchale Pipeline Extension	235 km (146 miles)	Extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro, Mexico	100%
Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas from Chihuahua to Topolobampo, Mexico	100%
In development			
Alaska Pipeline Project	2,737 km (1,700 miles)	To transport natural gas from Prudhoe Bay to Alberta, or from Prudhoe Bay to LNG facilities in south-central Alaska. We have an agreement with ExxonMobil to jointly advance the projects	
Coastal GasLink	650 km* (404 miles)	To deliver natural gas from the Montney gas-producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	
Prince Rupert Gas Transmission Project	750 km* (466 miles)	To deliver natural gas from North Montney gas producing region near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	

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

Further information about the Company's 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

TransCanada contracts and delivers North American crude oil supply to key U.S. markets. Our Oil Pipelines and related holdings are described below.

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

	Length	Description	Ownership
Oil pipelines			
Keystone Pipeline System	3,467 km (2,154 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma	100%
Under construction			
Cushing Marketlink	Crude oil receipt facilities	To transport crude oil from the Permian Basin producing region in western Texas to the U.S. Gulf Coast refining market on facilities that form part of the Gulf Coast Project	100%
Gulf Coast Project	780 km (485 miles)	To transport crude oil from the hub at Cushing, Oklahoma to the U.S. Gulf Coast refinery market. Includes the 76 km (47 mile) Houston Lateral pipeline	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 pipeline infrastructure and access to the Keystone Pipeline System	100%

	Length	Description	Ownership
In development			
Bakken Marketlink	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%
Canadian Mainline conversion		Conversion of a portion of the Canadian Mainline natural gas pipeline system to crude oil service, which will transport crude oil between Hardisty, Alberta and markets in eastern Canada	100%
Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil between the producing area northwest of Fort McMurray and the Edmonton/Heartland market region. Project is a partnership with Phoenix	50%
Keystone XL	1,897 km (1,179 miles)	Pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System to 1.4 million Bbl/d. Awaiting U.S. Presidential Permit decision	100%
Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and the Voyageur Upgrader located north of Fort McMurray, Alberta	100%

Further information about the Company's 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

Under the terms of the *National Energy Board Act* (Canada), the Canadian Mainline, the Alberta System and other Canadian pipelines owned or operated by TransCanada (collectively, the Systems) are regulated by the NEB. The NEB 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. In addition, 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 Pipeline Projects

The Coastal GasLink Pipeline and the Prince Rupert Gas Transmission projects are being proposed and developed primarily under the regulatory regime administered by the B.C. Oil and Gas Commission (BCOGC) and the B.C. Environmental Assessment Office (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*. Both projects are also subject to the provisions of the *Canadian Environmental Assessment Act*. Pre-application activities are currently underway with the BCOGC and BCEAO as well as the Canadian Environmental Assessment Agency.

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 Pipeline Projects

The Northern Courier Pipeline and Grand Rapids Pipeline projects are being proposed and developed primarily under the regulatory regime administered by the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment and Sustainable Resource Development (ESRD). ERCB 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 Bbl/d) of refined 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 pipeline 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 (CRE). The CRE regulates the construction and operation of pipeline facilities including the approval of tariffs, services and related rates. However, the contracts underpinning the facilities in Mexico are long-term negotiated rate contracts and not subject to further regulatory approval.

ENERGY BUSINESS

TransCanada's Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta. This segment of our business includes the acquisition, development, construction, ownership and operation of electrical power generation plants, the purchase and marketing of electricity, the provision of electricity account services to energy and industrial customers, and the development, construction, ownership and operation of natural gas storage in Alberta. Our Energy assets and related holdings are described below.

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	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[(1)]	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 Power Partnership[(2)])	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[(3)]	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[(3)]	natural gas	Combined-cycle plant	Toronto, Ontario	50%

	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[3]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
Bruce B	1,022[3]	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[4]		Underground facility connected to Alberta System	Crossfield, Alberta	100%
Edson	50 Bcf		Underground facility connected to Alberta System	Edson, Alberta	100%
In development					
Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
Ontario Solar	86	solar	Nine solar projects from Canadian Solar Solutions Inc. We expect to acquire the first two projects in the first half of 2013, and the remaining seven projects in 2013 to late 2014	Southern Ontario and New Liskeard, Ontario	100%

(1) Located in Arizona, results reported in Canadian Power   Western Power.

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

(3) Our share of power generation capacity.

(4) Reflects the acquisition of an additional 27 Bcf of working gas storage capacity in December 2012.

We own or have the rights to approximately 2,600 MW of 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 (we own 50% through the ASTC Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

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

We own or are developing approximately 3,000 MW of power generation capacity in eastern Canada. All of the power produced by these assets is sold under contract. Disciplined maintenance of plant operations is critical to the results of our eastern power assets, where earnings are based on plant availability and performance.

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

	Type of contract	With	Expires
Bécancour[1]	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

(1) Power generation has been suspended since 2008.

Assets currently in development are as follows:

	Type of contract	With	Expires
Ontario Solar	20-year Feed-in Tariff (FIT) contracts	OPA	20 years from in-service date
Napanee	20-year Clean Energy Supply contract	OPA	20 years from in-service date

We own approximately 3,800 MW of power generation capacity in New York and New England, including plants powered by natural gas, oil, hydro and wind.

We own or control 156 Bcf of non-regulated natural gas storage capacity in Alberta. This includes contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015. This business operates independently from our regulated natural gas transmission business and from ANR's regulated storage business, which are included in our Natural Gas Pipelines segment.

Further information about the Company's 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 approximately 4,900 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	2,247
Western Canada (excluding Calgary)	495
Houston	549
U.S. Midwest	468
U.S. Northeast	414
Eastern Canada	268
U.S. Southeast/Gulf Coast	275
U.S. West Coast	80
Mexico and South America	73
Total	**4,869**

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Health, Safety and Environment committee 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 for environmental management systems, conforms to external industry consensus standards and voluntary regulatory 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, 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 compared to previously set targets relating thereto, and taking into account incidents and highlights of performance in this regard during the relevant quarter, and reviews program 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, pipeline integrity, operational risk issues and applicable legislative developments. The committee also receives updates on any specific areas of operational risk management review currently 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 greenhouse gas 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 2012 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 pipeline safety record in 2012 continued to be better than industry benchmarks.

TransCanada routinely conducts emergency response field 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.

Aboriginal, Native American and stakeholder engagement

TransCanada has a number of policies, guiding principles and practices in place to help manage stakeholder engagement. TransCanada has adopted a code of business ethics which applies to our employees that 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 serve as a standard for TransCanada in our dealings with all stakeholders. The code may be viewed on our website (www.transcanada.com).

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. Key principles that guide TransCanada's engagement include: the Company's respect for the diversity of Aboriginal/Native American communities and recognition of the importance of the land to these communities; and our belief in engaging stakeholders from the earliest stages of our projects, through the project development process and into operations.

Risk factors

A discussion of the Company's 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

The 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, TransCanada's 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 TransCanada's 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 (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 five year 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 (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 five year 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 (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 five and a half year 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.

The dividends declared on the Series 1, 3 and 5 preferred shares during the past three completed financial years are set out in the following table:

	2012	2011	2010
Dividends declared on Series 1 preferred shares	$1.15	$1.15	$1.15
Dividends declared on Series 3 preferred shares	$1.00	$1.00	$0.80[(1)]
Dividends declared on Series 5 preferred shares	$1.10	$1.10	$0.65[(2)]

(1) Reflects dividends declared for the period from issuance on March 11, 2010 to December 31, 2010.

(2) Reflects dividends declared per share for the period from issuance on June 29, 2010 to December 31, 2010.

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

	2012	2011	2010
Dividends declared on common shares	$1.76	$1.68	$1.60

In February 2013, the Board approved an increase in the quarterly dividend on our outstanding common shares by five per cent to $0.46 per share from $0.44 per share for the quarter ending March 31, 2013.

Description of capital structure

SHARE CAPITAL

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 705,461,386 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which 22,000,000 Series 1 preferred shares, 14,000,000 Series 3 preferred shares and 14,000,000 Series 5 preferred shares are issued and outstanding. 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.

TransCanada has 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 the 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 TransCanada 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. Continuation of, and amendments to, the Shareholder rights plan will be voted on at the

2013 annual and special meeting of shareholders.

TransCanada has a dividend reinvestment and share purchase plan (DRP) which permits common and preferred shareholders of TransCanada and preferred shareholders of TCPL to elect to reinvest their cash dividends in additional common shares of TransCanada. Commencing with dividends declared in April 2011, common shares purchased with reinvested cash dividends were satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares were provided to the participants at a discount to the average market price in the five days before dividend payment, and shares provided in lieu of dividends were issued from treasury. The discount was set at three per cent in 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. 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. At our 2013 annual and special meeting of shareholders, TransCanada's shareholders will vote on reconfirming our stock option plan and any amendments as described in TransCanada's Management Information Circular dated February 11, 2013.

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 a 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, 2015 and 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 a 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 a 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.

Except as provided by the CBCA, the respective holders of the Series 1, 2, 3, 4, 5 and 6 preferred shares 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 respective holders of Series 1, 2, 3, 4, 5 and 6 preferred shares 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 Series 1, 2, 3, 4, 5 and 6 preferred share, respectively, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the Series 1, 2, 3, 4, 5 or 6 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	A3	A-
Medium-term notes	A	A3	A-
Junior subordinated notes	BBB (high)	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. 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 any qualifying negative factors that exist are considered manageable. The A 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 (high) 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 slightly 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 obligations. A short term debt rated A-2 is somewhat more susceptible to adverse effects of changes in economic conditions than higher rated categories; 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. TransCanada's Series 1, 3 and 5 preferred shares have been listed for trading on the TSX since September 30, 2009, March 11, 2010 and June 29, 2010, under the symbols TRP.PR.A, TRP.PR.B, and TRP.PR.C, 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 and 5 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 2012	$47.44	$45.30	$47.02	22,542,514	$47.78	$45.69	$47.32	8,599,319
November 2012	$45.98	$43.64	$45.98	20,383,391	$46.13	$43.56	$45.99	6,643,142
October 2012	$45.45	$43.16	$44.97	23,049,914	$46.58	$43.54	$45.23	4,749,881
September 2012	$45.61	$44.26	$44.74	23,361,386	$47.02	$44.27	$45.50	4,531,523
August 2012	$46.29	$44.36	$44.40	25,112,761	$46.76	$44.84	$45.07	7,970,340
July 2012	$46.00	$42.73	$45.67	30,066,257	$45.90	$41.68	$45.45	7,591,231
June 2012	$43.30	$41.47	$42.67	27,804,268	$42.56	$39.87	$41.90	8,808,940
May 2012	$43.55	$41.78	$42.33	24,869,200	$44.20	$40.35	$40.92	10,263,574
April 2012	$43.80	$42.10	$43.46	26,627,021	$44.50	$41.93	$43.98	10,157,804
March 2012	$44.60	$42.31	$42.83	30,474,321	$45.07	$42.38	$43.00	14,759,355
February 2012	$43.69	$41.02	$43.57	27,988,166	$44.21	$41.13	$43.98	10,105,156
January 2012	$44.75	$40.34	$41.25	36,915,568	$44.28	$39.74	$41.05	14,839,199

SERIES 1 PREFERRED SHARES

Month	TSX (TRP.PR.A) High ($)	Low ($)	Close ($)	Volume Traded
December 2012	$25.75	$25.25	$25.69	251,155
November 2012	$25.70	$25.21	$25.33	345,144
October 2012	$25.85	$25.41	$25.50	214,250
September 2012	$25.95	$25.46	$25.81	94,025
August 2012	$26.15	$25.64	$25.77	183,141
July 2012	$26.03	$25.50	$25.80	103,746
June 2012	$25.82	$25.26	$25.70	217,717
May 2012	$26.24	$25.40	$25.50	203,126
April 2012	$26.22	$25.80	$26.18	814,719
March 2012	$26.46	$25.60	$25.80	173,582
February 2012	$27.19	$26.15	$26.20	202,767
January 2012	$27.17	$26.15	$26.57	352,329

SERIES 3 PREFERRED SHARES

Month	TSX (TRP.PR.B) High ($)	Low ($)	Close ($)	Volume Traded
December 2012	$24.47	$24.14	$24.43	321,065
November 2012	$24.97	$24.15	$24.23	309,882
October 2012	$25.10	$24.82	$24.96	423,217
September 2012	$25.36	$24.79	$24.90	493,093
August 2012	$25.69	$25.20	$25.33	110,019
July 2012	$25.60	$25.05	$25.39	235,273

June 2012	$25.25	$24.96	$25.12	384,867
May 2012	$25.69	$25.05	$25.20	205,547
April 2012	$25.66	$25.30	$25.43	543,553
March 2012	$25.58	$25.00	$25.35	274,498
February 2012	$26.15	$25.35	$25.36	407,748
January 2012	$25.79	$25.25	$25.63	459,012

SERIES 5 PREFERRED SHARES

Month	TSX (TRP.PR.C) High ($)	Low ($)	Close ($)	Volume Traded
December 2012				