TransCanada Corporation

2013 Annual information form

February 19, 2014

TransCanada

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Presentation of information

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

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2013 (**Year End**). Amounts are expressed in Canadian dollars unless otherwise indicated. Information in relation to metric conversion can be found at *Schedule A* to this AIF. The *Glossary* found at the end of this AIF contains certain terms defined throughout this AIF and abbreviations and acronyms that may not otherwise be defined in this document.

Certain portions of TransCanada's Management's Discussion and Analysis dated February 19, 2014 (**MD&A**) are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TransCanada's profile.

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

Forward-looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains certain information that is forward-looking and is subject to important risks and uncertainties.

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

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

Forward-looking statements contained or incorporated by reference in this AIF may include information about the following, among other things:

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

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

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

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging

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

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of our counterparties
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

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

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

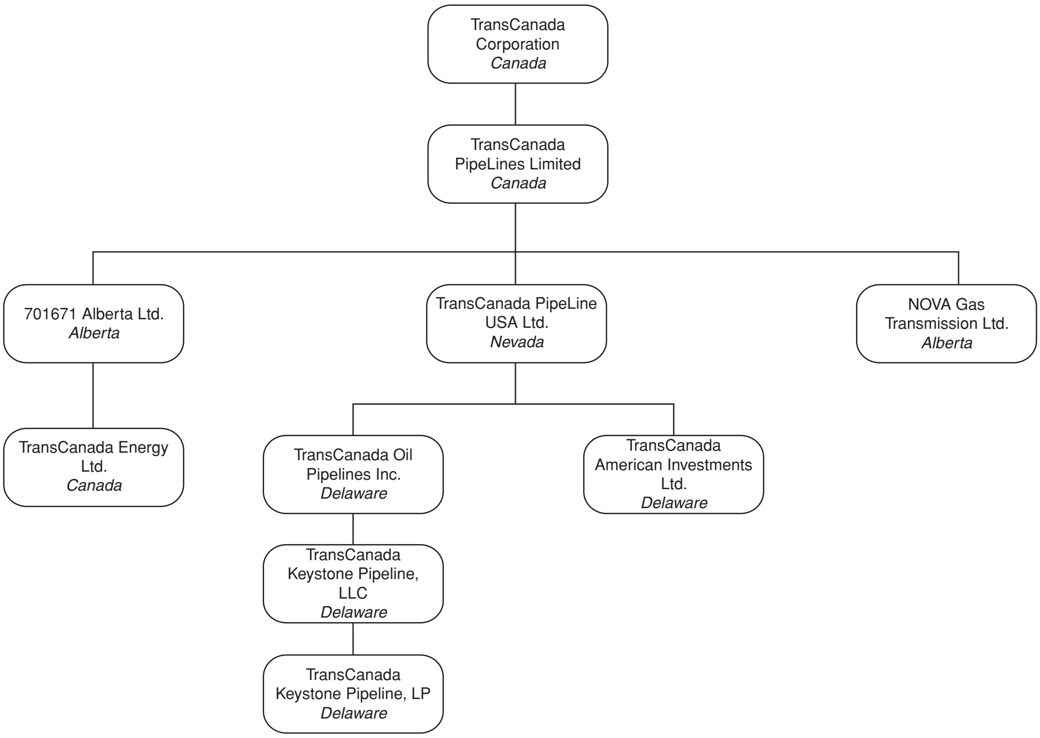
TransCanada Corporation

CORPORATE STRUCTURE

Our head office and registered office are located at 450 - 1st Street S.W., Calgary, Alberta, T2P 5H1. TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporations Act* (**CBCA**) on February 25, 2003 in connection with the Arrangement, which established TransCanada as the parent company of TCPL. The Arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the Arrangement became effective May 15, 2003. Pursuant to the Arrangement, the common shareholders of TCPL exchanged each of their TCPL common shares for one common share of TransCanada. The debt securities and preferred shares of TCPL remained obligations and securities of TCPL. TCPL continues to carry on business as the principal operating subsidiary of TransCanada. TransCanada does not hold any material assets directly, other than the common shares of TCPL and receivables from certain of TransCanada's subsidiaries.

INTERCORPORATE RELATIONSHIPS

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TransCanada's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the total consolidated assets of TransCanada or revenues that exceeded 10 per cent of the total consolidated revenues of TransCanada as at Year End. TransCanada beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares in each of these subsidiaries, with the exception of TransCanada Keystone Pipeline, LP in which TransCanada indirectly holds 100 per cent of the partnership interests.



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

General development of the business

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

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Oil Pipelines and Energy businesses, respectively, and certain acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years and year to date in 2014.

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Canadian Pipelines

Date	Description of development
NGTL System (formerly known as the Alberta System) and expansion projects	
January 2011	We received approval from the National Energy Board (**NEB**) to construct the Horn River pipeline.
March 2011	We commenced construction of the $275 million Horn River pipeline. We also executed an agreement to extend the Horn River pipeline by approximately 100 kilometres (km) (62 mile). An application requesting approval to construct and operate this extension was filed with the NEB in October 2011.
August 2011	The NEB approved construction of a 24 km (15 mile) extension of the Groundbirch pipeline and construction commenced.
October 2011	Commercial integration of the NGTL System and ATCO Pipelines (**ATCO**) system commenced. Under an agreement, the facilities of the NGTL System and ATCO system are commercially operated as a single transmission system and transportation service is provided to customers by us pursuant to the NGTL System's tariff and suite of rates and services. The agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of the NGTL System and ATCO system.
October 2011	The NEB approved the construction of natural gas pipeline projects for the NGTL System.
November – December 2011	The regulatory decisions by which commercial integration of the NGTL System and ATCO system was authorized were the subject of appeals to the Federal Court of Appeal. We continued to work with ATCO to gather information for the final stage of the integration which is to swap assets of equal value and will require approval by both the Alberta Utilities Commission and the NEB.
May 2012	The Horn River project was completed, extending the NGTL System into the Horn River shale play in British Columbia (**B.C.**). The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 million cubic feet per day (**MMcf/d**) by 2020.
June 2012	The NEB approved the Leismer-Kettle River Crossover project, a 77 km (46 mile) pipeline to expand the NGTL System with the intent of increasing capacity to meet demand in northeastern Alberta. The expected cost of the expansion is $160 million.
December 2012	The current settlements for the NGTL System expired. Final tolls for 2013 were to be determined through either new settlements or rate cases and any orders resulting from the NEB's decision on the Canadian Restructuring Proposal.
January 2013	The NEB issued its recommendation to the Governor-in-Council that the proposed Chinchaga Expansion component of the Komie North project be approved, but denied the proposed Komie North Extension component.
August 2013	We signed agreements for approximately two billion cubic feet per day (**Bcf/d**) of firm gas transportation services to underpin the development of a major pipeline extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. (the **North Montney project**). The proposed North Montney project will include an interconnection with our proposed PRGT (as defined below) project to provide natural gas supply to the proposed Pacific NorthWest LNG export facility near Prince Rupert, B.C. and is expected to cost approximately $1.7 billion, which includes $100 million for downstream facilities. Under commercial arrangements, receipt volumes are expected to increase between 2016 and 2019 to an aggregate volume of approximately two Bcf/d and delivery volumes to the PRGT project are expected to be approximately 2.1 Bcf/d beginning in 2019. We also entered into arrangements with other parties for transportation services that will utilize the North Montney project facilities.
August 2013	We reached settlement of the NGTL System annual revenue requirement for the years 2013 and 2014 with shippers and other interested parties (the **NGTL 2013-2014 Settlement**). The settlement fixed the return at 10.1 per cent on a 40 per cent deemed common equity, established an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixed the OM&A costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We also requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application.
November 2013	We filed an application with the NEB to construct and operate the North Montney project. The estimated capital cost of the project is $1.7 billion and it consists of approximately 300 km (186 mile) of pipeline.
November 2013	The NEB approved the NGTL 2013-2014 Settlement and final 2013 rates, as filed, in November 2013. We expect the final tolls for 2014 for the NGTL System will be determined on the basis of the NGTL settlement process.

Date	Description of development
Canadian Mainline	
January – February 2011	We received approval for revised interim tolls, effective March 1, 2011 which increased interim tolls from the current interim tolls which were based on 2010 final tolls, to more closely align with tolls calculated in accordance with the 2007-2011 settlement with stakeholders.
September 2011	To respond to the evolving changes in flow patterns on the Canadian Mainline, we developed a comprehensive business and services restructuring proposal. The Canadian Restructuring Proposal application with the NEB culminated from extensive discussion and negotiation with our shippers. The NEB established interim tolls for 2012 based on the approved 2011 final tolls.
November – December 2011	We filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as then approved 2011 final tolls. The NEB approved our application for 2011 final tolls for the Canadian Mainline at the level of the tolls that were being charged on an interim basis. Final 2011 tolls were calculated in accordance with previously approved toll methodologies and were based on the principles contained in the 2007-2011 settlement with stakeholders, with adjustments to reduce toll impacts. Certain aspects of the 2011 revenue requirement were rolled into the Canadian Restructuring Proposal.
May 2012	We received NEB approval to build new pipeline facilities to provide Ontario and Quebec markets with additional gas supplies from the Marcellus shale basin.
May 2012	The additional open season for firm transportation service on the Canadian Mainline, to bring additional Marcellus shale gas into Canada, closed. We were able to accommodate an additional 50 MMcf/d from the Niagara meter station to Kirkwall, Ontario, effective November 2012.
November 2012	Transportation of natural gas supply from the Marcellus shale basin supply began moving on the Canadian Mainline.
March 2013	We received the NEB decision on our Canadian Restructuring Proposal application to change the business structure and the terms and conditions of service for the Canadian Mainline. The NEB decision established a Toll Stabilization Account (**TSA**) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five year term of the decision. The NEB decision also identified certain circumstances that would require a new tolls application prior to the end of the five year term. One of those circumstances is if the TSA balance becomes positive, which occurred in 2013.
May 2013	We filed a compliance filing and an application for a review and variance of the NEB decision regarding the Canadian Restructuring Proposal.
June 2013	The NEB dismissed the review and variance application and set out a process to consider the tariff revisions. Additional changes to the Canadian Mainline's tariff were considered by the NEB as a separate application which was heard in an oral hearing.
July 2013	The NEB released its reasons for the dismissal. We began implementation of the NEB decision related to the Canadian Restructuring Proposal. Since implementation, an additional 1.3 Bcf/d of firm service originating at Empress, Alberta has been contracted for, more than doubling the contracted capacity of this location. The implementation of the NEB decision was a key priority in 2013 and with the ability to price discretionary services at market prices we were able to essentially meet our overall cost of service requirements for 2013.
September 2013	The Canadian Mainline and the three largest Canadian local distribution companies entered into a settlement (**LDC Settlement**) which was filed with the NEB for approval in December 2013. The LDC Settlement, if approved, will establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculates tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also includes an incentive mechanism that requires a $20 million (after tax) annual contribution by us from 2015 to 2020, which could result in a range of ROE outcomes from 8.70 per cent to 11.50 per cent. The LDC Settlement will enable the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement is intended to provide a market driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retains pricing flexibility for discretionary services and implements certain tariff changes and new services as required by the terms of the settlement. The NEB decision remains in effect pending the outcome of the LDC Settlement application.
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016. This represents a significant amount of volume renewal, especially by Canadian shippers.

Date	Description of development
U.S. Pipelines	
Gas Transmission Northwest LLC (GTN)	
May 2011	We closed the sale of a 25 per cent interest in each of GTN and Bison Pipeline LLC (**Bison**) to TC PipeLines, LP (**TCLP**) for a total transaction value of US$605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
November 2011	The Federal Energy Regulatory Commission (**FERC**) approved a settlement agreement between GTN and its shippers for new transportation rates to be effective January 2012 through December 2015. This settlement also requires GTN to file for new rates that are to be effective January 2016.
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold a 28.9 per cent interest in and are the General Partner of, TCLP.
Bison	
January 2011	Bison pipeline was placed into commercial service.
May 2011	We closed the sale of a 25 per cent interest in each of GTN and Bison to TCLP for a total transaction value of US$605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold a 28.9 per cent interest in and are the General Partner of, TCLP.
Great Lakes	
November 2013	Great Lakes received FERC approval for a rate settlement with its shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from its recourse rate contracts. The settlement includes a 17 month moratorium through March 2015 and requires us to have new rates in effect by January 1, 2018.
Northern Border	
January 2013	Northern Border secured a final settlement agreement with its shippers that the FERC approved in December 2012, effective January 2013. The settlement rates for long haul transportation are approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also includes a three year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.
ANR Pipeline	
June 2012	The FERC issued orders approving ANR's sale of its offshore assets to a newly created wholly owned subsidiary, TC Offshore LLC (**the LLC**), allowing the LLC to operate these assets as a stand alone interstate pipeline.
August 2012	The FERC approved ANR Storage Company's settlement with its shippers.
November 2012	The LLC began commercial operations.
ANR Lebanon Lateral Reversal Project	
October 2013	We concluded a successful binding open season. We have executed firm transportation contracts for 350 MMcf/d at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal project, which will entail modifications to existing facilities. The facility modifications are expected to be completed in the first quarter 2014. Contracted volumes will increase over the course of 2014 generating incremental earnings. The project will substantially increase our ability to receive gas on ANR's southeast mainstream from the Utica/Marcellus shale areas.
Mexican Pipelines	
Topolobampo and Mazatlan Pipeline projects	
November 2012	The CFE awarded us with the contract to build, own and operate the Topolobampo pipeline project. The Topolobampo project is a 530 km (329 mile), 30 inch pipeline with a capacity of 670 MMcf/d and an estimated cost of US$1 billion that will deliver gas from El Encino, Chihuahua and interconnects with third party pipelines in El Oro, Sinaloa to Topolobampo, Sinaloa.
November 2012	The CFE awarded us with the contract to build, own and operate the Mazatlan pipeline project, from El Oro to Mazatlan, Mexico. The Mazatlan project is a 413 km (257 mile), 24 inch pipeline running from El Oro to Mazatlan, within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million.
First Quarter 2014	Permitting and engineering activities are advancing as planned for these two northwest Mexico pipelines. Both projects are supported by 25 year contracts with the CFE and are expected to be in service mid to late 2016.

Date	Description of development
Tamazunchale Pipeline Extension project	
February 2012	We signed a contract with the CFE for the Tamazunchale Pipeline Extension project. Engineering, procurement and construction contracts were signed and construction related activities began.
First Quarter 2014	The construction of the US$500 million Tamazunchale Pipeline Extension project is proceeding although delays have occurred due to a significant number of archeological finds within the pipeline route. It is expected these findings and related alternative construction will move the project's scheduled in service date to second quarter 2014. As these types of findings are not uncommon in significant infrastructure projects in Mexico, contractual relief for such delays is provided. We continue to work with local, state and federal authorities to minimize and mitigate ground disturbance at the specific sites as well as to minimize impact to the scheduled in service date.
Guadalajara	
June 2011	The Guadalajara pipeline was completed. We and CFE agreed to add a US$60 million compressor station to the pipeline.
First Quarter 2013	The compressor station went into service.
LNG Pipeline Projects	
Coastal GasLink	
June 2012	We were selected to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion, 650km (404 mile) pipeline is expected to have an initial capacity of 1.7 Bcf/d and will transport natural gas from the Montney gas producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG export facility near Kitimat, B.C.
January 2014	We filed the Application for an Environmental Assessment Certificate with the B.C. Environmental Assessment Office (**BCEAO**). We are currently focused on community, landowner, government and First Nations engagement as the project advances through the regulatory process. The pipeline would be placed in service near the end of the decade, subject to a final investment decision to be made by LNG Canada after obtaining final regulatory approvals. We continue to advance this project and all costs would be recoverable should the project not proceed.
Prince Rupert Gas Transmission Project (PRGT)	
January 2013	We were selected to design, build, own and operate the proposed $5 billion, 750 km (466 mile) PRGT. The proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St John, B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C. We are currently focused on First Nations, community, landowner and government engagement as the PRGT advances through the regulatory process with the BCEAO. We continue to refine our study corridor based on consultation and detailed studies to date. A final investment decision to construct the project, for a planned in service date of late 2018, is expected to be made following final regulatory approvals. We continue to advance this project and all costs would be fully recoverable should the project not proceed.
Alaska LNG Project	
March 2012	Three major producers (the **Alaska North Slope producers**), along with us through participation in the Alaska LNG Project, announced the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources through an LNG option. This would involve construction of a natural gas pipeline from the North Slope to Valdez, Alaska where the gas would be liquefied and shipped to international markets.
May 2012	We received approval from the State of Alaska to suspend and preserve our activities on the Alaska/Alberta route and focus on the LNG alternative. This allowed us to defer our obligation to file for a U.S. FERC certificate for the Alberta route beyond fall 2012, our original deadline.
July 2012	The Alaska LNG Project announced a non-binding public solicitation of interest in securing capacity on a potential new pipeline system to transport Alaska's North Slope gas. The solicitation of interest took place between August 2012 and September 2012. There were a number of non-binding expressions of interest from potential shippers from a broad range of industry sectors in North America and Asia.
January 2014	The State of Alaska is proposing new legislation that would transition from the *Alaska Gasline Inducement Act* and enable a new commercial arrangement to be established with us, the Alaska North Slope producers, and the Alaska Gasline Development Corp. It has also been agreed that an LNG export project, rather than a pipeline to Alberta, is the best opportunity to commercialize Alaska North Slope gas resources in current market conditions. It is anticipated that two years of front end engineering will be completed before further commitments to commercialize the project will be made.

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

DEVELOPMENTS IN THE OIL PIPELINES BUSINESS

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

Date	Description of development
March 2013	The DOS released its Draft Supplemental Environmental Impact Statement for Keystone XL. The impact statement reaffirmed construction of the 830,000 Bbl/d Keystone XL project would not result in any significant impact to the environment.
January 2014	The DOS released its Final Supplemental Environmental Impact Statement (**FSEIS**) for Keystone XL. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is unlikely to significantly impact the rate of extraction in the oil sands and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas (**GHG**) emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period of up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment.
February 2014	A Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL project. We will now analyze the judgment and decide what next steps may be taken. Nebraska's Attorney General has filed an appeal. We anticipate the pipeline, which will extend from Hardisty, Alberta to Steele City, Nebraska, to be in service approximately two years following the receipt of the Presidential Permit. The US$5.4 billion cost estimate will increase depending on the timing and conditions of the permit. Any capital cost increase above the initial estimated capital cost, up to a specified amount, is shared between us and the shippers such that 75 per cent of the change in capital cost is reflected in the fixed payment received by us. Any capital cost increase above the specified amount is shared equally between us and the shippers. As of December 31, 2013, we have invested US$2.2 billion in the project.
Energy East Pipeline	
April 2013	We announced that we were holding an open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets. The open season followed a successful expression of interest phase and discussions with prospective shippers.
August 2013	We announced we are moving forward with the 1.1 million Bbl/d Energy East Pipeline as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries in Québec in 2018 with service to New Brunswick to follow in late 2018. We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. We intend to file the necessary regulatory applications in mid 2014 for approvals to construct and operate the pipeline project and terminal facilities.
Northern Courier Pipeline	
August 2012	We announced that we were selected by Fort Hills Energy Limited Partnership (**FHELP**) to design, build, own and operate the proposed Northern Courier Pipeline. The pipeline system is fully subscribed under long-term contract to service the Fort Hills mine, which is jointly owned by Suncor Energy Inc. (**Suncor**) and two other companies.
April 2013	We filed a permit application with the Alberta Energy Regulator (**AER**) after completing the required Aboriginal and stakeholder engagement and associated field work.
October 2013	Suncor announced that the FHELP is proceeding with the Fort Hills oil sands mining project and that it expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project is expected to cost $800 million and will transport bitumen and diluent between the Fort Hills mine site and Suncor's terminal located north of Fort McMurray, Alberta.
Heartland Pipeline and TC Terminals	
May 2013	We announced we had reached binding long-term shipping agreements to build, own and operate the Heartland Pipeline and TC Terminals projects, and filed a permit application for the terminal facility. The projects will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton/Heartland, Alberta market to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. We anticipate the pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to be placed in service in 2016.
October 2013	We filed a permit application for the pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.
February 2014	The application for the terminal facility was approved.
Keystone Hardisty Terminal	
March 2012	We launched and concluded a binding open season to obtain commitments from interested parties for the Keystone Hardisty Terminal.
May 2012	We announced that we had secured binding long-term commitments of more than 500,000 Bbl/d for the Keystone Hardisty Terminal, and are expanding the proposed two million barrel project to a 2.6 million barrel terminal at Hardisty, Alberta, due to strong commercial support.
May 2013	We started construction on the Keystone Hardisty Terminal which we anticipate will have a storage capacity of up to 2.6 million barrels of crude oil. The $300 million crude oil terminal at Hardisty, Alberta is expected to be in service in 2016.

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

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

DEVELOPMENTS IN THE ENERGY BUSINESS

Date	Description of development
Ontario Solar	
December 2011	We agreed to buy nine Ontario solar generation facilities (combined capacity of 86 megawatt (**MW**)) from Canadian Solar Solutions Inc. (**Canadian Solar**), for approximately $500 million. Under the terms of the agreement, Canadian Solar will develop and build each of the nine solar facilities using photovoltaic panels. We buy each facility once construction and acceptance testing are complete and commercial operation begins. All power produced by the solar facilities is currently or will be sold under 20 year PPAs with the OPA.
June 2013	We completed the acquisition of the first facility for $55 million.
September 2013	We completed the acquisition of two solar facilities for $99 million.
December 2013	We completed the acquisition of a fourth solar facility for $62 million. We expect the acquisition of the remaining five facilities to close in 2014, subject to satisfactory completion of the related construction activities and regulatory approvals.
Cancarb Limited and Cancarb Waste Heat Facility	
January 2014	We announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility for $190 million subject to closing adjustments. The sale is expected to close in late first quarter 2014.
Bécancour	
June 2011	Hydro-Québec Distribution (**Hydro-Québec**) notified us it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2012. Under the original agreement, Hydro-Québec had the option to extend the suspension on an annual basis until such time as regional electricity demand levels recover.
June 2012	Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013.
June 2013	Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014.
December 2013	We entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continues to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended. Final execution of this amendment is conditional on the pending approval by the Régie de l'énergie.
Sundance	
January 2011	The Sundance A Units 1 and 2 were subject to a force majeure claim by the operator.
February 2011	The operator informed us that it was not economic to replace or repair Sundance A Units 1 and 2, and that the Sundance A PPA should be terminated. We disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA. Throughout 2011, revenues and costs had been recorded as though the outages were interruptions of supply in accordance with the terms of the PPA.
July 2012	An arbitration panel decided that the Sundance A PPA should not be terminated and ordered the operator to rebuild Units 1 and 2. The panel also limited the operator's force majeure claim from November 20, 2011 until the units could reasonably be returned to service. The operator announced that it expected the units to be returned to service in the fall of 2013. Since we considered the outages to be an interruption of supply, we accrued $188 million in pretax income between December 2010 and March 2012. The outcome of the decision was that we received approximately $138 million of this amount. We recorded the $50 million difference as a pre-tax charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011. We did not record further revenue or costs from the PPA until the units were returned to service. The net book value of the Sundance A PPA recorded in Intangibles and Other Assets remained fully recoverable.
November 2012	An arbitration decision was reached with the arbitration panel granting partial force majeure relief to the operator with respect to Sundance B Unit 3, and we reduced our equity earnings by $11 million from the ASTC Power Partnership (**ASTC**) to reflect the amount that will not be recovered as result of the decision. In 2010, Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components and was subject to a force majeure claim by the operator. The ASTC, which holds the Sundance B PPA, disputed the claim under the binding dispute resolution process provided in the PPA because we did not believe the operator's claim met the test of force majeure. We therefore recorded equity earnings from our 50 per cent ownership interest in ASTC as though this event were a normal plant outage.
September 2013	Sundance A Unit 1 returned to service.
October 2013	Sundance A Unit 2 returned to service.

Date	Description of development
Bruce Power	
February 2011	The Bruce Power Refurbishment Implementation Agreement (the **BPRIA**) was amended to extend the suspension date for Bruce A contingent support payments from December 31, 2011 to June 1, 2012. Contingent support payments received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A was subject to spot prices effective June 1, 2012 until the restart of both Units 1 and 2 was complete. Bruce Power and the OPA had amended certain terms and conditions of the BPRIA in July 2009, which included: amendments to the Bruce B floor price mechanism, the removal of a support payment cap for Bruce A, an amendment to the capital cost-sharing mechanism, and addition of a provision for deemed generation payments to Bruce Power at the contracted prices under circumstances where generation from Bruce A and Bruce B is reduced due to system curtailments on the Independent Electricity System Operator controlled grid in Ontario. Under the original BPRIA, which was signed in 2005, Bruce A committed to refurbish and restart the then currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. Fuelling of both Unit 2 and Unit 1 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.
November 2011	Bruce Power commenced the West Shift Plus outage as part of the life extension strategy for Unit 3.
March 2012	Bruce Power received authorization from the Canadian Nuclear Safety Commission to power up the Unit 2 reactor.
May 2012	An incident occurred within the Unit 2 electrical generator on the non-nuclear side of the plant which delayed the synchronization of Unit 2 to the Ontario electrical grid. As a result, Bruce Power submitted a force majeure claim to the OPA.
June 2012	Bruce Power returned Unit 3 to service after completing the $300 million West Shift Plus life extension outage, which began in 2011. Unit 4 was expected to return to service in late first quarter 2013 after the completion of an expanded outage investment program that began in August 2012. These investments should allow Units 3 and 4 to produce low cost electricity until at least 2021.
August 2012	We confirmed that Bruce Power's force majeure claim to the OPA related to Unit 2 (**Bruce A**) had been accepted. The claim was the result of a May 2012 event that delayed the synchronization of this unit to the Ontario power grid. With the acceptance of the force majeure claim, Bruce Power continued to receive the contracted price for power generated from the operating units at Bruce A after July 1, 2012.
October 2012	Unit 1 and 2 were returned to service following the completion of the refurbishment. The incident in May 2012 within the Unit 2 electrical generator on the non-nuclear side of the plant had delayed returning the units to service. Bruce Power's force majeure claim to the OPA was accepted in August, and it continued to receive the contracted price for power generated during the force majeure period.
November 2012	Both Units 1 and 2 have operated at reduced output levels following their return to service, and Bruce Power took Unit 1 offline for an approximate one month maintenance outage. Bruce Power expects the availability percentages for Units 1 and 2 to increase over time, however, these units have not operated for an extended period of time and may experience slightly higher forced outage rates and reduced availability percentages in 2013. All that time, overall plant availability for Bruce A was expected to be approximately 90 per cent in 2013.
April 2013	Bruce Power announced that it had reached an agreement with the OPA to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.
April 2013	Bruce Power returned Bruce A Unit 4 to service after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Unit 4 to operate until at least 2021.
January 2014	Cameco Corporation announced it had agreed to sell its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We are considering our option to increase our Bruce B ownership percentage.
Napanee	
December 2012	We signed a contract with the OPA to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. Currently, the project is on schedule and we expect to complete the permitting process in late 2014. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018.
Cartier Wind	
November 2011	The Montagne-Sèche project and phase one of the Gros-Morne wind farm were completed.
November 2012	We placed the second phase of the Gros-Morne wind farm project in service, completing the 590 MW, five phase Cartier Wind Project in Québec. All of the power produced by Cartier Wind is sold to Hydro-Québec under 20 year PPAs.

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

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

Business of TransCanada

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Oil Pipelines and Energy. At Year End and for the year then ended, Natural Gas Pipelines accounted for approximately 51 per cent of revenues and 47 per cent of our total assets, Oil Pipelines accounted for approximately 13 per cent of revenues and 25 per cent of our total assets' and Energy accounted for approximately 36 per cent of revenues and 25 per cent of our total assets. The following table shows our revenues from operations by segment, classified geographically, for the years ended December 31, 2013 and 2012.

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

(1) Exports include pipeline revenues attributable to deliveries to U.S. pipelines and power deliveries to U.S. markets.

(2) Revenues include sales of natural gas.

(3) Revenues are attributed to countries based on country of origin of product or service.

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

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. We also have regulated natural gas storage facilities in Michigan.

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

	Length	Description	Effective Ownership
Canadian pipelines			
NGTL System	24,522 km (15,237 miles)	Gathers and transports natural gas within Alberta and northeastern B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border to serve eastern Canada and the U.S. northeast markets	100%
Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. midwest, Pacific northwest, California and Nevada	100%
Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
U.S. pipelines			
ANR			100%
Pipeline	16,121 km (10,017 miles)	Transports natural gas from producing fields in Texas and Oklahoma, from offshore and onshore regions of the Gulf of Mexico and from the U.S. midcontinent, for delivery to the Gulf Coast region as well as Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	
Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TCLP	50.2%
GTN	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TCLP	50.2%
Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 67 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.9 per cent interest in TCLP	67%
Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%
North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with another third-party system on the California/Mexico border. We effectively own 28.9 per cent of the system through our interest in TCLP	28.9%
Northern Border	2,265 km (1,407 miles)	Transports natural gas through the U.S. Midwest, and connects with Foothills near Monchy, Saskatchewan. We effectively own 14.5 per cent of the system through our 28.9 per cent interest in TCLP	14.5%
Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 28.9 per cent of the system through our interest in TCLP	28.9%

	Length	Description	Effective Ownership
Mexican pipelines			
Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi	100%
Under construction			
Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Sinaloa in Mexico. Will connect to the Topolobampo Pipeline at El Oro.	100%
Tamazunchale Pipeline Extension	235 km (146 miles)	To extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro and other parts of central Mexico	100%
Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
In development			
Alaska LNG Pipeline	1,448 km* (900 miles)	To transport natural gas from Prudhoe Bay to LNG facilities in Nikiski, Alaska	
Coastal GasLink	650 km* (404 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
Prince Rupert Gas Transmission	750 km* (466 miles)	To deliver natural gas from North Montney gas producing region at a NGTL interconnect near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
North Montney Mainline	306 km* (190 miles)	To deliver natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline	100%

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

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

OIL PIPELINES BUSINESS

Our existing crude oil pipeline infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S. Gulf Coast.

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

	Length	Description	Ownership
Oil pipelines			
Keystone Pipeline System (includes Gulf Coast project)	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, Cushing, Oklahoma, and to the U.S. Gulf Coast refining market	100%
Under construction			
Cushing Marketlink Receipt Facility	Crude oil receipt facilities	To facilitate the transportation of crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System	100%
Houston Lateral and Terminal	77 km (48 miles)	To transport crude oil from the Keystone Pipeline System to Houston, Texas	100%
Keystone Hardisty Terminal	Crude oil terminal	Crude oil terminal to be located at Hardisty, Alberta, providing western Canadian producers with new crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
In development			
Bakken Marketlink Receipt Facility	Crude oil receipt facilities	To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland market region	50%
Keystone XL	1,897 km (1,179 miles)	Crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
Energy East Pipeline	4,500 km (2,700 miles)		100%

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

REGULATION OF THE NATURAL GAS AND OIL PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

The Canadian Mainline, NGTL System and most of the other Canadian pipelines owned or operated by TransCanada (collectively, the **Systems**) are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

The NEB generally sets tolls that provide TransCanada the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for each of the Systems. The decision of the NEB in March 2013 in respect of the Canadian Mainline approved the 2011 revenue requirement as filed, approved tolls charged in 2012 as final with any variance between revenues and costs deferred for recovery in future years, and set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others. Further information relating to the decision from the NEB regarding the Canadian Restructuring Proposal as well as the LDC Settlement can be found in the *General Developments of the business – Developments in the Natural Gas Pipelines business – Canadian Mainline* section above.

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

Natural Gas Pipelines Projects

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

Oil Pipelines

The NEB regulates the terms and conditions of service, including rates, and the physical operation of the Canadian portion of the Keystone Pipeline System, including the Keystone Hardisty Terminal. NEB approval is also required for facility additions. The rates for transportation service on the Keystone Pipeline System are calculated in accordance with a methodology agreed to in transportation service agreements between Keystone and its shippers, and approved by the NEB.

Oil Pipelines Projects

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

United States

Natural Gas Pipelines

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

Oil Pipelines

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

Mexico

Natural Gas Pipelines

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

ENERGY BUSINESS

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

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

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

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

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

	Generating capacity (MW)	Type of fuel	Description	Location	Ownership
Canadian Power 8,070 MW of power generation capacity (including facilities in development)					
Western Power 2,636 MW of power supply in Alberta and the western U.S.					
Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
Cancarb[1]	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TransCanada facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
Coolidge[2]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
Sheerness PPA	756	coal	PPA for entire output of facility	Hanna, Alberta	100%
Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
Sundance B PPA (Owned by ASTC[3])	353[3]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
Eastern Power 2,950 MW of power generation capacity (including facilities in development)					
Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
Cartier Wind	366[4]	wind	Five wind power projects	Gaspésie, Québec	62%
Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
Portlands Energy	275[4]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
Ontario Solar	36	solar	Four solar facilities	Southern Ontario	100%

	Generating capacity (MW)	Type of fuel	Description	Location	Ownership
Bruce Power 2,484 MW of power generation capacity through eight nuclear power units					
Bruce A	1,462[4]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
Bruce B	1,022[4]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%
U.S. Power 3,755 MW of power generation capacity					
Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
In development					
Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
Ontario Solar	50	solar	Acquisition of five remaining solar facilities from Canadian Solar in 2014	Southern Ontario and New Liskeard, Ontario	100%

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

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

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

(4) Our share of power generation capacity.

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

Power purchased under long-term contracts is as follows:

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

Power sold under long-term contracts is as follows:

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

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

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

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

(1) Power generation has been suspended since 2008.

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

Assets currently in development are as follows:

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

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

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

General

EMPLOYEES

At Year End, TransCanada's principal operating subsidiary, TCPL, had 5,551 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

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

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

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

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

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

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

Environmental policies

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

Safety and asset integrity

As one of TransCanada's priorities, safety is an integral part of the way our employees work. Since 2008, we have sustained year over year improvement in our safety performance. Overall, TransCanada's incident frequency rates in 2013 continued to be better than most industry benchmarks.

The safety and integrity of our existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. Our safety record in 2013 continued to exceed industry benchmarks.

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

Social Policies

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

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

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

Risk factors

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

Dividends

Our Board has not adopted a formal dividend policy. The Board reviews the financial performance of TransCanada quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, our payment of dividends is primarily funded from dividends it receives as the sole common shareholder of TCPL. Provisions of various trust indentures and credit arrangements to which TCPL is a party restrict TCPL's ability to declare and pay dividends to TransCanada under certain circumstances and, if such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends. In the opinion of TransCanada's management, such provisions do not currently restrict or alter TransCanada's ability to declare or pay dividends.

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

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

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

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

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

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

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

(1) Issued March 4, 2013.

(2) Issued January 20, 2014.

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

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

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

Description of capital structure

SHARE CAPITAL

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 707,441,314 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which the following were issued and outstanding as at Year End, or as otherwise indicated below.

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

(1) Issued January 20, 2014.

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

Common shares

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

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

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

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

First preferred shares

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

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

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

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

The Series 1 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The Series 1 preferred shares are redeemable by TransCanada in whole or in part on December 31, 2014, and on December 31 in every fifth year thereafter, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 1 preferred shares have the right to convert their shares into cumulative redeemable Series 2 preferred shares, subject to certain conditions, on December 31, 2014 and on December 31 in every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.92 per cent and have the right to convert their shares into Series 1 preferred shares, subject to certain conditions, on December 31, 2019 and on December 31 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1 preferred shares shall be entitled to receive $25.00 per Series 1 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 1 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 2 preferred shares are substantially the same as the Series 1 preferred shares. The Series 2 preferred shares are redeemable by TransCanada in whole or in part on any date after December 31, 2014, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on December 31, 2019 and on December 31 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 3 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 3 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 3 preferred shares are redeemable by TransCanada in whole or in part on June 30, 2015, and on June 30 in every fifth year thereafter, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 3 preferred shares have the right to convert their shares into cumulative redeemable Series 4 preferred shares, subject to certain conditions, on June 30, 2015 and on June 30 in every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.28 per cent and have the right to convert their shares into Series 3 preferred shares, subject to certain conditions, on June 30, 2020 and on June 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 3 preferred shares shall be entitled to receive $25.00 per Series 3 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 3 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 4 preferred shares are substantially the same as the Series 3 preferred shares. The Series 4 preferred shares are redeemable by TransCanada in whole or in part on any date after June 30, 2015, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on June 30, 2020 and on June 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 5 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 5 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 5 preferred shares are redeemable by TransCanada in whole or in part on January 30, 2016, and on January 30 in every fifth year thereafter, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 5 preferred shares have the right to convert their shares into cumulative redeemable Series 6 preferred shares, subject to certain conditions, on January 30, 2016 and on January 30 in every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.54 per cent and have the right to convert their shares into Series 5 preferred shares, subject to certain conditions, on January 30, 2021 and on January 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 5 preferred shares shall be entitled to receive $25.00 per Series 5 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 5 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 6 preferred shares are substantially the same as the Series 5 preferred shares. The Series 6 preferred shares are redeemable by TransCanada in whole or in part on any date after January 30, 2016, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on January 30, 2021 and on January 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 7 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 7 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 7 preferred shares are redeemable by TransCanada in whole or in part on April 30, 2019, and on April 30 in every fifth year thereafter, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 7 preferred shares have the right to convert their shares into cumulative redeemable Series 8 preferred shares, subject to certain conditions, on April 30, 2019 and on April 30 in every fifth year thereafter. The holders of Series 8 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90 day Government of Canada treasury bill rate and 2.38 per cent and have the right to convert their shares into Series 8 preferred shares, subject to certain conditions, on April 30, 2024 and on April 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 7 preferred shares shall be entitled to receive $25.00 per Series 7 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 7 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 8 preferred shares are substantially the same as the Series 7 preferred shares. The Series 8 preferred shares are redeemable by TransCanada in whole or in part on any date after April 30, 2019, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on April 30, 2024 and on April 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

The Series 9 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 9 preferred shares are substantially identical to those attaching to the Series 1 preferred shares, except as outlined below. The Series 9 preferred shares are redeemable by TransCanada in whole or in part on October 30, 2019, and on October 30 in every fifth year thereafter, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 9 preferred shares have the right to convert their shares into cumulative redeemable Series 10 preferred shares, subject to certain conditions, on October 30, 2019 and on October 30 in every fifth year thereafter. The holders of Series 10 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90 day Government of Canada treasury bill rate and 2.35 per cent and have the right to convert their shares into Series 9 preferred shares, subject to certain conditions, on October 30, 2024 and on October 30 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 9 preferred shares shall be entitled to receive $25.00 per Series 9 preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 9 preferred shares. Other than with respect to redemption rights (as described below), the material characteristics of the Series 10 preferred shares are substantially the same as the Series 9 preferred shares. The Series 10 preferred shares are redeemable by TransCanada in whole or in part on any date after October 30, 2019, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on October 30, 2024 and on October 30 in every fifth year thereafter, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

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

Second preferred shares

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

Credit ratings

Although TransCanada has not issued debt to the public, it has been assigned credit ratings by Moody's Investors Service, Inc. (**Moody's**) and Standard & Poor's (**S&P**) and its outstanding preferred shares have also been assigned credit ratings by Moody's, S&P and DBRS Limited (**DBRS**). Moody's has assigned an issuer rating of Baa1 with a stable outlook and S&P has assigned a long-term corporate credit rating of A– with a stable outlook. TransCanada does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL.

The following table sets out the current credit ratings assigned to those outstanding classes of securities of the Company and TCPL which have been rated by DBRS, Moody's and S&P:

	DBRS	Moody's	S&P
Senior unsecured debt			
Debentures	A (low)	A3	A–
Medium-term notes	A (low)	A3	A–
Junior subordinated notes	BBB	Baa1	BBB
Preferred shares	Pfd-2 (low)	Baa2	P-2
Commercial paper	R-1 (low)	–	A-2
Trending/rating outlook	Stable	Stable	Stable

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

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

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

DBRS

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

MOODY'S

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are applied to each rating classification from Aa through Caa, with 1 being the highest and 3 being the lowest. The A3 rating assigned to TCPL's senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are considered upper medium grade and are subject to low credit risk. The Baa1 and Baa2 ratings assigned to TCPL's junior subordinated debt and preferred shares, respectively, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated debt ranking slightly higher within the Baa rating category with a modifier of 1 as opposed to the modifier of 2 on the preferred shares. Obligations rated Baa are subject to moderate credit risk, are considered medium-grade, and as such, may possess certain speculative characteristics.

S&P

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

Market for securities

TransCanada's common shares are listed on the TSX and the New York Stock Exchange (**NYSE**) under the symbol TRP. Our Series 1, 3, 5, 7 and 9 preferred shares have been listed for trading on the TSX since September 30, 2009, March 11, 2010, June 29, 2010, March 4, 2013 and January 20, 2014 under the symbols TRP.PR.A, TRP.PR.B, TRP.PR.C, TRP.PR.D, and TRP.PR.E, respectively. The following tables set out the reported monthly high, low, and month end closing trading prices and monthly trading volumes of the common shares of TransCanada on the TSX and the NYSE, and the respective Series 1, 3, 5 and 7 preferred shares on the TSX, for the period indicated:

COMMON SHARES

	TSX (TRP)				NYSE (TRP)			
Month	High ($)	Low ($)	Close ($)	Volume Traded	High (US$)	Low (US$)	Close (US$)	Volume Traded
December 2013	$48.93	$46.10	$48.54	22,141,189	$46.02	$43.32	$45.66	10,823,386
November 2013	$48.48	$46.61	$46.85	25,329,959	$46.45	$44.17	$44.39	8,847,429
October 2013	$47.24	$43.94	$46.99	21,425,127	$45.25	$42.41	$45.11	8,263,822
September 2013	$46.51	$44.89	$45.25	20,209,858	$44.94	$43.06	$43.94	7,668,690
August 2013	$48.48	$44.75	$45.91	20,421,616	$46.79	$42.59	$43.62	9,854,808
July 2013	$47.79	$45.10	$46.93	23,656,071	$46.12	$42.83	$45.72	12,784,623
June 2013	$47.94	$44.62	$45.28	33,556,916	$46.97	$42.39	$43.11	16,760,131
May 2013	$51.21	$47.07	$47.56	26,146,463	$49.65	$45.54	$45.85	8,960,677
April 2013	$50.26	$47.65	$49.94	26,052,153	$49.60	$46.58	$49.51	12,440,623
March 2013	$50.08	$47.40	$48.50	25,384,945	$48.90	$46.05	$47.89	12,382,311
February 2013	$48.87	$46.80	$48.04	25,462,009	$48.87	$45.80	$46.51	9,828,080
January 2013	$49.44	$46.82	$47.21	26,082,774	$49.64	$47.16	$47.37	11,080,878

SERIES 1 PREFERRED SHARES

Month	TSX (TRP.PR.A) High ($)	Low ($)	Close ($)	Volume Traded
December 2013	$24.54	$23.10	$23.72	336,208
November 2013	$24.80	$23.58	$24.55	278,223
October 2013	$24.67	$23.26	$24.11	287,790
September 2013	$25.14	$24.19	$24.65	379,661
August 2013	$24.90	$23.20	$24.70	307,979
July 2013	$25.24	$24.41	$24.43	289,147
June 2013	$25.29	$23.12	$24.76	299,266
May 2013	$25.59	$25.16	$25.19	677,235
April 2013	$25.79	$25.22	$25.45	514,560
March 2013	$25.75	$25.35	$25.66	405,750
February 2013	$26.00	$25.33	$25.49	413,651
January 2013	$26.00	$25.50	$25.75	444,889

SERIES 3 PREFERRED SHARES

Month	TSX (TRP.PR.B) High ($)	Low ($)	Close ($)	Volume Traded
December 2013	$20.63	$20.03	$20.37	998,882
November 2013	$21.16	$19.98	$20.68	517,633
October 2013	$20.64	$19.94	$20.03	290,469
September 2013	$22.09	$19.91	$20.14	922,863
August 2013	$22.96	$20.27	$21.72	312,075
July 2013	$23.94	$22.81	$22.86	349,059
June 2013	$24.90	$22.60	$23.19	263,285
May 2013	$24.97	$24.55	$24.76	448,999
April 2013	$24.90	$24.37	$24.65	571,040
March 2013	$25.04	$24.32	$24.93	508,121
February 2013	$24.90	$24.34	$24.56	621,184
January 2013	$25.00	$24.39	$24.80	555,279

SERIES 5 PREFERRED SHARES

Month	TSX (TRP.PR.C) High ($)	Low ($)	Close ($)	Volume Traded
December 2013	$22.90	$21.26	$21.75	387,442
November 2013	$23.19	$22.26	$23.09	770,771
October 2013	$23.74	$22.00	$22.75	251,607
September 2013	$23.97	$22.50	$23.34	450,168
August 2013	$23.73	$21.25	$23.10	270,842
July 2013	$24.75	$23.00	$23.30	329,537
June 2013	$25.65	$24.25	$24.74	177,521
May 2013	$25.75	$25.39	$25.60	235,352
April 2013	$25.79	$25.40	$25.50	292,516
March 2013	$26.08	$25.41	$25.59	321,154
February 2013	$25.87	$25.44	$25.62	285,166
January 2013	$25.95	$25.30	$25.70	282,832

SERIES 7 PREFERRED SHARES

Month	TSX (TRP.PR.D) High ($)	Low ($)	Close ($)	Volume Traded
December 2013	$25.50	$25.00	$25.11	686,593
November 2013	$25.48	$24.50	$25.45	528,477
October 2013	$25.12	$24.50	$25.05	765,889
September 2013	$25.05	$23.85	$24.84	383,697
August 2013	$25.12	$23.80	$24.87	478,375
July 2013	$25.61	$24.95	$25.18	639,196
June 2013	$25.87	$24.72	$25.16	912,786
May 2013	$26.10	$25.70	$25.75	640,573
April 2013	$26.15	$25.82	$26.00	1,990,847
March 2013	$26.15	$25.25	$26.00	3,292,039

In addition, TransCanada's subsidiary, TCPL, has cumulative redeemable first preferred shares, series Y listed on the TSX under the symbol TCA.PR.Y, which will be redeemed on March 5, 2014 at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends. TCPL's cumulative redeemable first preferred shares, series U, were listed on the TSX under the symbol TCA.PR.X until their redemption on October 15, 2013.

SERIES U PREFERRED SHARES AND SERIES Y PREFERRED SHARES

	Series U (TCA.PR.X)				Series Y (TCA.PR.Y)			
Month	High ($)	Low ($)	Close ($)	Volume Traded	High ($)	Low ($)	Close ($)	Volume Traded
December 2013	—	—	—	—	$50.50	$49.71	$49.85	83,846
November 2013	—	—	—	—	$50.47	$50.12	$50.26	54,495
October 2013	$50.60	$50.54	$50.56	23,177	$50.32	$49.66	$50.20	55,215
September 2013	$50.60	$48.59	$50.53	900,300	$50.69	$48.85	$49.86	54,314
August 2013	$50.29	$47.02	$49.10	54,733	$50.45	$48.10	$49.15	49,888
July 2013	$50.22	$49.49	$50.19	36,528	$50.23	$49.90	$50.02	107,214
June 2013	$50.80	$49.70	$49.90	42,967	$51.03	$49.85	$49.98	54,370
May 2013	$51.06	$50.54	$50.70	47,008	$51.48	$50.74	$50.95	63,103
April 2013	$51.05	$50.46	$50.90	40,609	$51.85	$50.79	$51.20	37,508
March 2013	$51.79	$50.55	$51.01	43,088	$52.48	$51.51	$51.94	49,268
February 2013	$52.04	$50.61	$51.15	89,555	$52.94	$52.05	$52.20	82,717
January 2013	$52.19	$51.58	$51.71	38,797	$52.90	$52.25	$52.90	128,629

Directors and officers

As of February 19, 2014, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction, directly or indirectly, over an aggregate of 452,965 common shares of TransCanada. This constitutes less than one per cent of TransCanada's common shares. The Company collects this information from our directors and officers but otherwise we have no direct knowledge of individual holdings of TransCanada's securities.

DIRECTORS

The following table sets forth the names of the directors who serve on the Board, as of February 19, 2014 (unless otherwise indicated), together with their jurisdictions of residence, all positions and offices held by them with TransCanada, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the Arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Kevin E. Benson Calgary, Alberta Canada	Corporate director, Director, Calgary Airport Authority from January 2010 to December 2013. President and Chief Executive Officer, Laidlaw International, Inc. from June 2003 to October 2007.	2005
Derek H. Burney[1], O.C. Ottawa, Ontario Canada	Senior strategic advisor at Norton Rose Fulbright (law firm). Chairman, Gardaworld International's (risk management and security services) Advisory Board since April 2008. Advisory Board member, Paradigm Capital Inc. (investment dealer) since 2011. Chair, Canwest Global Communications Corp. (media and communications) from August 2006 (director since April 2005) to October 2010.	2002
The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Stein Monast L.L.P. (law firm). Director, Metro Inc. (food retail) since January 2001, Royal Bank of Canada (chartered bank) since October 1991 and the Fondation du Musée national des beaux-arts du Québec. Director, Institut Québecois des Hautes Études Internationales, Laval University from August 2002 to June 2009, RBC Dexia Investors Trust until October 2011 and Care Canada from October 2010 to December 2011.	2002
Russell K. Girling Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 2010. Chief Operating Officer from July 2009 to June 2010 and President, Pipelines from June 2006 to June 2010. Director, Agrium Inc. (agricultural) since May 2006.	2010
S. Barry Jackson Calgary, Alberta Canada	Corporate director, Chair of the Board, TransCanada since April 2005. Director, WestJet Airlines Ltd. (airline) since February 2009 and Laricina Energy Ltd. (oil and gas, exploration and production) since December 2005. Director, Nexen Inc. (**Nexen**) (oil and gas, exploration and production) from 2001 to June 2013, Chair of the board, Nexen from 2012 to June 2013.	2002

Name and place of residence	Principal occupation during the five preceding years	Director since
Paula Rosput Reynolds Seattle, Washington U.S.A.	President and Chief Executive Officer, PreferWest, LLC (business advisory group) since October 2009. Director, Anadarko Petroleum Corporation (oil and gas, exploration and production) since August 2007, Delta Air Lines, Inc. (airline) since August 2004 and BAE Systems plc. (aerospace, defence, information security) since April 2011. Vice-Chair and Chief Restructuring Officer, American International Group Inc. (insurance and financial services) from October 2008 to September 2009.	2011
John Richels[(2)] Nichols Hills, Oklahoma U.S.A.	President and Chief Executive Officer, Devon Energy Corporation (**Devon**) (oil and gas, exploration and production, energy infrastructure) since 2010 (President since 2004). Director, Devon since 2007 and BOK Financial Corp. (financial services) since 2013. Chairman, American Exploration and Production Council since May 2012. Former Vice-Chairman of the board of governors, Association of Petroleum Producers.	2013
Mary Pat Salomone[(3)(4)] Bonita Springs, Florida U.S.A.	Corporate director. Senior Vice-President and Chief Operating Officer, The Babcock & Wilcox Company (**B&W**) (energy infrastructure) from January 2010 to June 2013. Manager Business Development from 2009 to 2010 and Manager, Strategic Acquisitions from 2008 to 2009, Babcock & Wilcox Nuclear Operations Group Inc. (**B&W Nuclear**). Director, United States Enrichment Corporation (basic materials, nuclear) from December 2011 to October 2012.	2013
W. Thomas Stephens[(5)] Greenwood Village, Colorado U.S.A.	Corporate director. Trustee, Putnam Mutual Funds. Chair and Chief Executive Officer, Boise Cascade, LLC (paper, forest products and timberland assets) from November 2004 to November 2008. Director, Boise Inc. from February 2008 to April 2010.	2007
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Pengrowth Energy Corporation (oil and gas, exploration and production) since December 2010. Canadian Energy Services & Technology Corp. (chemical, oilfield services) since January 2010 and Northpoint Resources Ltd. (oil and gas, exploration and production) since July 2013. Director, C&C Energia Ltd. (oil and gas) from May 2010 to December 2012 and Orleans Energy Ltd. (oil and gas) from October 2008 to December 2010. Director, Pengrowth Corporation (administrator of Pengrowth Energy Trust) from October 2006 to December 2010. Director, Canadian Energy Services Inc. (general partner of Canadian Energy Services L.P.) from January 2006 to December 2009.	2006
Richard E. Waugh Toronto, Ontario Canada	Corporate director. Former Deputy Chairman, President and Chief Executive Officer, The Bank of Nova Scotia (**Scotiabank**) (chartered bank) until January 2014.[(6)] Director, Catalyst Inc. (non-profit) from February 2007 to November 2013 and Chair, Catalyst Canada Advisory Board from February 2007 to October 2013.	2012

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

(2) Mr. Richels joined the Board effective June 19, 2013.

(3) Ms. Salomone joined the Board effective February 12, 2013.

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

(5) Mr. Stephens previously served on the Board from 2000 to 2005.

(6) Mr. Waugh was President and Chief Executive Officer of Scotiabank until November 2013 where he then served as Deputy Chairman and director of Scotiabank until January 31, 2014.

BOARD COMMITTEES

TransCanada has four committees of the Board: the Audit committee, the Governance committee, the Health, Safety and Environment committee and the Human Resources committee. The voting members of each of these committees, as of February 19, 2014, are identified below. Mr. Burney was appointed as the Chair of the Governance committee at the first Governance Committee meeting held in 2013, effective February 11, 2013. Mr. Stewart was appointed Chair of the Health, Safety and Environment committee effective April 26, 2013.

Director	Audit committee	Governance committee	Health, Safety and Environment committee	Human Resources committee
Kevin E. Benson	Chair	✓		
Derek H. Burney	✓	Chair		
Paule Gauthier			✓	✓
S. Barry Jackson		✓		✓
Paula Rosput Reynolds			✓	✓
John Richels		✓		✓
Mary Pat Salomone	✓		✓	
W. Thomas Stephens			✓	Chair
D. Michael G. Stewart	✓		Chair	
Richard E. Waugh	✓	✓		

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

OFFICERS

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

Executive officers

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	Prior to July 2010, Chief Operating Officer since July 2009 and President, Pipelines since June 2006.
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Karl R. Johannson	Executive Vice-President and President, Natural Gas Pipelines	Prior to November 2012, Senior Vice-President, Canadian and Eastern U.S. Pipelines, Prior to January 2011. Senior Vice-President, Power Commercial since January 2006.
Gregory A. Lohnes(1)	Executive Vice-President, Operations and Major Projects	Prior to November 2012, Executive Vice-President and President, Natural Gas Pipelines. Prior to July 2010, Executive Vice-President and Chief Financial Officer since June 2006.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
Dennis J. McConaghy(2)	Executive Vice-President, Corporate Development	Prior to July 2010, Executive Vice-President, Pipeline Strategy and Development since May 2006.
Sean McMaster(1)	Executive Vice-President, Stakeholder Relations and General Counsel and Chief Compliance Officer	Prior to February 2012, Executive Vice-President, Corporate and General Counsel since January 2007 and Chief Compliance Officer since July 2006.
Alexander J. Pourbaix	President, Energy and Oil Pipelines	Prior to July 2010, Executive Vice-President, Corporate Development since July 2009 and President, Energy since June 2006.

(1) Retiring effective February 28, 2014.

(2) Effective February 28, 2014, Mr. McConaghy's title will change from Executive Vice-President, Corporate Development to Executive Vice-President of TransCanada until his retirement later this year.

Effective March 1, 2014, the executive officers of TransCanada will be:

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	Prior to July 2010, Chief Operating Officer since July 2009 and President, Pipelines since June 2006.
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Karl R. Johannson	Executive Vice-President and President, Natural Gas Pipelines	Prior to November 2012, Senior Vice-President, Canadian and Eastern U.S. Pipelines. Prior to January 2011, Senior Vice-President, Power Commercial since January 2006.
Dennis J. McConaghy(1)	Executive Vice-President	Prior to March 2014, Executive Vice-President, Corporate Development since July 2010. Prior to July 2010, Executive Vice-President, Pipeline Strategy and Development since May 2006.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
Alexander J. Pourbaix	Executive Vice-President and President, Development	Prior to March 2014, President, Energy and Oil Pipelines. Prior to July 2010, President, Energy. Prior to July 2010, Executive Vice-President, Corporate Development since July 2009 and President, Energy since June 2006.
James M. Baggs	Executive Vice-President, Operations and Engineering	Prior to March 2014, Senior Vice-President, Operations and Engineering. Prior to June 2012, Vice-President, Operations and Engineering. Prior to July 2009, Vice-President, Field Operations and Engineering since June 2006 (TCPL).
Kristine L. Delkus	Executive Vice-President, General Counsel and Chief Compliance Officer	Prior to March 2014, Senior Vice-President, Pipelines Law and Regulatory Affairs. Prior to June 2012, Deputy General Counsel, Pipelines and Regulatory Affairs since September 2006 (TCPL).
Paul E. Miller	Executive Vice-President and President, Liquids Pipelines	Prior to March 2014, Senior Vice-President, Oil Pipelines. Prior to December 2010, Vice-President, Oil Pipelines. Prior to July 2010, Vice-President, Keystone Pipeline since May 2008 (TCPL).
William C. Taylor	Executive Vice-President and President, Energy	Prior to March 2014, Senior Vice-President, US and Canadian Power. Prior to May 2013, Senior Vice-President, Eastern Power. Prior to July 2010, Vice-President and General Manager, U.S. Northeast Power since May 2008 (TCPL).

(1) Effective February 28, 2014, Mr. McConaghy's title will change from Executive Vice-President, Corporate Development to Executive Vice-President of TransCanada until his retirement later this year.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Sean M. Brett	Vice-President and Treasurer	Prior to July 2010, Vice-President, Commercial Operations of TC PipeLines GP, Inc., and Director, LP Operations of TCPL. Prior to December 2009, Director, Joint Venture Management, Keystone Pipeline Project of TCPL since December 2008.
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation since April 2002.
Joel E. Hunter	Vice-President, Finance	Prior to July 2010, Director, Corporate Finance since January 2008.
Christine R. Johnston	Vice-President and Corporate Secretary	Prior to March 2012, Vice-President, Finance Law. Prior to January 2010, Vice-President, Corporate Development Law. Prior to September 2009, Associate General Counsel, Corporate Development and Finance Law since September 2005.
Garry E. Lamb	Vice-President, Risk Management	Vice-President, Risk Management since October 2001.
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller since June 2006.

CONFLICTS OF INTEREST

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

Serving on other boards

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

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

If a director declares that they have an interest in a material contract or transaction that is being considered by the Board, the director leaves the meeting so the matter can be discussed and voted on.

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

Affiliates

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

Corporate governance

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

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

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

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

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

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

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

Audit committee

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

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The members of the Audit committee as of February 19, 2014 are Kevin E. Benson (Chair), Derek H. Burney, Mary Pat Salomone, D. Michael G. Stewart and Richard E. Waugh. Ms. Salomone and Mr. Waugh were appointed members of the Audit committee effective February 12, 2013 and February 1, 2014, respectively.

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

Kevin E. Benson

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

Derek H. Burney

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

Mary Pat Salomone

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

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science in Geological Sciences with First Class Honours from Queen's University. He has served and continues to serve on the boards of several public companies and other organizations and on the audit committee of certain of those boards. Mr. Stewart held a number of senior executive positions with Westcoast Energy Inc. including Executive Vice-President, Business Development. He has also been active in the Canadian energy industry for over 40 years.

Richard E. Waugh

Mr. Waugh holds a Bachelor of Commerce (Honours) degree from the University of Manitoba and a Master of Business Administration from York University. He is a Fellow of the Institute of Canadian Bankers and has been awarded Honorary Doctor of Laws degrees from York University and Assumption University. Mr. Waugh was Deputy Chairman and a director of Scotiabank. Starting as a branch employee in 1970, he worked in increasingly senior roles at Scotiabank including President from January 2003 to October 2012 and Chief Executive Officer from December 2003 to November 2013. Mr. Waugh also serves on the boards of a number of private and non-profit corporations.

PRE-APPROVAL POLICIES AND PROCEDURES

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

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

EXTERNAL AUDITOR SERVICE FEES

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

($ millions)	2013	2012
Audit fees • audit of the annual consolidated financial statements • services related to statutory and regulatory filings or engagements • review of interim consolidated financial statements and information contained in various prospectuses and other securities offering documents	$6.4	$5.7
Audit-related fees • services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment plans	0.2	0.1
Tax fees • Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings	0.7	0.5
All other fees • review of information system design procedures • services related to vendor analytics and environmental compliance credits	—	0.6
Total fees	**$7.3**	**$6.9**

Legal proceedings and regulatory actions

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

Transfer agent and registrar

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

Interest of experts

TransCanada's auditors, KPMG LLP, have confirmed that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and also that they are independent accountants with respect to TransCanada under all relevant U.S. professional and regulatory standards.

Additional information

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

Glossary

Units of measure

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

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
Canadian Restructuring Proposal	Canadian Mainline business and services restructuring proposal and 2012 and 2013 Mainline final tolls application
cogeneration facilities (or plant)	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSE	Health, safety and environment
LNG	Liquefied natural gas
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement or agreement
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
ASU	Accounting Standards Update
DRP	Dividend reinvestment plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
GAAP	U.S. generally accepted accounting principles

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOS	Department of State (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
ISO	Independent System Operator
LMCI	Land Matters Consultation Initiative (Canada)
NEB	National Energy Board (Canada)
OPA	Ontario Power Authority (Canada)
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission

Schedule A
Metric conversion table

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

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

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

Schedule B
Charter of the Audit Committee

1. PURPOSE

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

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

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

2. ROLES AND RESPONSIBILITIES

I. Appointment of the Company's External Auditors

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

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

II. Oversight in Respect of Financial Disclosure

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

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

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

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

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

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

(f) review and discuss quarterly findings reports from the external auditors on:
   (i) all critical accounting policies and practices to be used;
   (ii) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor;
   (iii) other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences;
(g) review with management and the external auditors the effect of regulatory and accounting developments as well as any off-balance sheet structures on the Company's financial statements;
(h) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including arbitration and tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;
(i) review disclosures made to the Audit Committee by the Company's CEO and CFO during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls;
(j) discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies;

III. Oversight in Respect of Legal and Regulatory Matters

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

IV. Oversight in Respect of Internal Audit

(a) review the audit plans of the internal auditors of the Company including the degree of coordination between such plans and those of the external auditors and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;
(b) review the significant findings prepared by the internal audit department and recommendations issued by it or by any external party relating to internal audit issues, together with management's response thereto;
(c) review compliance with the Company's policies and avoidance of conflicts of interest;
(d) review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with subsidiaries and affiliates;
(e) ensure the internal auditor has access to the Chair of the Audit Committee and of the Board and to the Chief Executive Officer and meet separately with the internal auditor to review with him or her any problems or difficulties he or she may have encountered and specifically:
   (i) any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;
   (ii) any changes required in the planned scope of the internal audit;
   (iii) the internal audit department responsibilities, budget and staffing;

   and to report to the Board on such meetings;

V. Insight in Respect of the External Auditors

(a) review any letter, report or other communication from the external auditors in respect of any identified weakness or unadjusted difference and management's response and follow-up, inquire regularly of management and the external auditors of any significant issues between them and how they have been resolved, and intervene in the resolution if required;
(b) receive and review annually the external auditors' formal written statement of independence delineating all relationships between itself and the Company;

(c) meet separately with the external auditors to review with them any problems or difficulties the external auditors may have encountered and specifically:
   (i) any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management;
   (ii) any changes required in the planned scope of the audit;
   and to report to the Board on such meetings;
(d) meet with the external auditors prior to the audit to review the planning and staffing of the audit;
(e) receive and review annually the external auditors' written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;
(f) review and evaluate the external auditors, including the lead partner of the external auditor team;
(g) ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years;

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

(a) pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:
   (i) the aggregate amount of all such non-audit services provided to the Company that were not pre-approved constitutes not more than 5% of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;
   (ii) such services were not recognized by the Company at the time of the engagement to be non-audit services;
   (iii) such services are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee;
(b) approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;
(c) the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval;
(d) if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection;

VII. Oversight in Respect of Certain Policies

(a) review and recommend to the Board for approval the implementation and amendments to policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's codes of business ethics and Risk Management and Financial Reporting policies;
(b) obtain reports from management, the Company's senior internal auditing executive and the external auditors and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's codes of business conduct and ethics;
(c) establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;
(d) annually review and assess the adequacy of the Company's public disclosure policy;
(e) review and approve the Company's hiring policies for partners, employees and former partners and employees of the present and former external auditors (recognizing the Sarbanes-Oxley Act of 2002 does not permit the CEO, controller, CFO or chief accounting officer to have participated in the Company's audit as an employee of the external auditors during the preceding one-year period) and monitor the Company's adherence to the policy;

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

(a) review and approve annually the Statement of Investment Beliefs for the Company's pension plans;
(b) delegate the ongoing administration and management of the financial aspects of the Canadian pension plans to the Pension Committee ("Pension Committee") comprised of members of the Company's management team appointed by the Human Resources Committee, in accordance with the Pension Committee Charter, which terms shall be approved by both the Audit Committee and the Human Resources Committee, and the terms of the Statement of Investment Beliefs;
(c) monitor the financial management activities of the Pension Committee and receive updates at least annually from the Pension Committee on the investment of the Plan assets to ensure compliance with the Statement of Investment Beliefs;
(d) provide advice to the Human Resources Committee on any proposed changes in the Company's pension plans in respect of any significant effect such changes may have on pension financial matters;
(e) review and consider financial and investment reports and the funded status relating to the Company's pension plans and recommend to the Board on pension contributions;
(f) receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;
(g) approve the initial selection or change of actuary for the Company's pension plans;
(h) approve the appointment or termination of auditors;

IX. U.S. Stock Plans

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

X. Oversight in Respect of Internal Administration

(a) review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates;
(b) oversee succession planning for the senior management in finance, treasury, tax, risk, internal audit and the controllers' group; and

XI. Information Security

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

XII. Oversight Function

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

3. COMPOSITION OF AUDIT COMMITTEE

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

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

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

6. AUDIT COMMITTEE CHAIR
The Board shall appoint a Chair of the Audit Committee who shall:

(a) review and approve the agenda for each meeting of the Audit Committee and, as appropriate, consult with members of management;
(b) preside over meetings of the Audit Committee;
(c) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;
(d) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and
(e) meet as necessary with the internal and external auditors.

7. ABSENCE OF AUDIT COMMITTEE CHAIR
If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. SECRETARY OF AUDIT COMMITTEE
The Corporate Secretary shall act as Secretary to the Audit Committee.

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

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

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

12. ATTENDANCE OF COMPANY OFFICERS AND EMPLOYEES AT MEETING
At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. PROCEDURE, RECORDS AND REPORTING

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

14. REVIEW OF CHARTER AND EVALUATION OF AUDIT COMMITTEE

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

15. OUTSIDE EXPERTS AND ADVISORS

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

16. RELIANCE

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