TransCanada Corporation

2014 Annual information form

February 12, 2015

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, 2014 (**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 12, 2015 (**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 this document – Non-GAAP measures* section of the MD&A for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents, which section of the MD&A is incorporated by reference herein.

Forward-looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains certain information that is forward-looking and is subject to important risks and uncertainties. We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

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

Forward-looking statements 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 and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

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

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

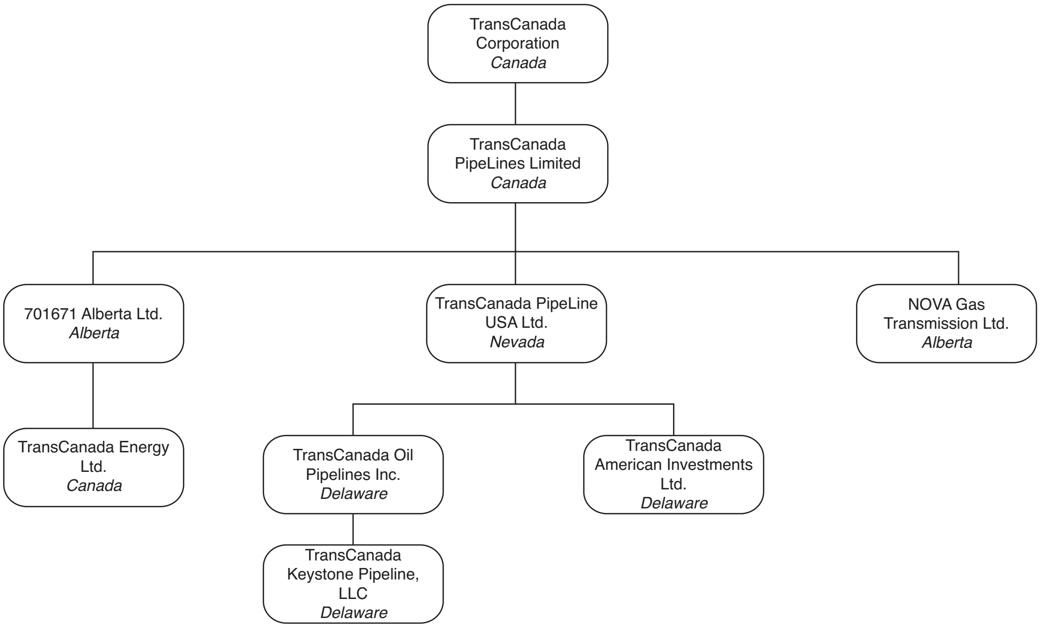
TransCanada Corporation

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.



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

General development of the business

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

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Liquids Pipelines and Energy businesses, respectively, and certain acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years and year to date in 2015.

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Canadian Regulated Pipelines

Date	Description of development
NGTL System	
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 National Energy Board (**NEB**) approved the Leismer-Kettle River Crossover project, a 77 km (46 miles) pipeline to expand the NGTL System with the intent of increasing capacity to meet demand in northeastern Alberta.
January 2013	The NEB issued its recommendation to the Governor-in-Council that the proposed Chinchaga Expansion component of the Komie North project be approved, but denied the proposed Komie North Extension component.
April 2013	The Leismer-Kettle River Crossover project was placed into service. The cost of the expansion was $150 million.
March 2014	We received an NEB Safety Order (the **Order**) in response to the recent pipeline releases on the NGTL System. The Order required us to reduce the maximum operating pressure on three per cent of NGTL's pipeline segments. We filed a request for a review and variance of the Order that would minimize gas disruptions while still maintaining a high level of safety.
March 2014	The NEB approved approximately $400 million in NGTL facility expansions that were in various stages of development or construction.
April 2014	The NEB granted the review and variance request with certain conditions. We are accelerating components of our integrity management program to address the NEB Order.
Fourth Quarter 2014	We continue to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern B.C. from unconventional gas plays and substantive growth in intra-basin delivery markets. This demand growth is driven primarily by oil sands development, gas-fired electric power generation and expectations of B.C. west coast LNG projects. This demand for NGTL System services is expected to result in approximately 4.0 billion cubic feet per day (Bcf/d) of incremental firm services with approximately 3.1 Bcf/d related to firm receipt services and 0.9 Bcf/d related to firm delivery services. We will be seeking regulatory approvals in 2015 to construct new facilities to meet these service requests of approximately 540 km (336 miles) of pipeline, seven compressor stations, and 40 meter stations that will be required in 2016 and 2017 (**2016/17 Facilities**). The estimated total capital cost for the facilities is approximately $2.7 billion. Including the new 2016/17 Facilities, the North Montney Mainline, the Merrick Mainline, and other new supply and demand facilities, the NGTL System has approximately $6.7 billion of commercially secured projects in various stages of development.
North Montney Mainline	
August 2013	We signed agreements for approximately two 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 proposed North Montney Pipeline will include an interconnection with our proposed PRGT (as defined below) project to provide natural gas supply to the proposed Pacific NorthWest liquefied natural gas (**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.
November 2013	We filed an application with the NEB to construct and operate the North Montney Pipeline.
February 2014	The NEB issued a Hearing Order for the North Montney Pipeline. The proposed project consists of approximately 300 km (186 miles) of pipeline and is expected to be placed in service in two sections, Aitken Creek in second quarter 2016 and Kahta in second quarter 2017.
December 2014	The hearing for the application before the NEB to build and operate this project concluded. We expect the NEB to issue its report and recommendations for the project by the end of April 2015.
Merrick Mainline	
June 2014	We announced the signing of agreements for approximately 1.9 Bcf/d of firm natural gas transportation services to underpin the development of a major extension of our NGTL System. The proposed Merrick Mainline will transport natural gas sourced through the NGTL System to the inlet of the proposed Pacific Trail Pipeline that will terminate at the Kitimat LNG Terminal at Bish Cove near Kitimat, B.C. The proposed project will be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C. The $1.9 billion project will consist of approximately 260 km (161miles) of 48-inch diameter pipe. Subject to the necessary approvals, which includes the regulatory approval from the NEB for us to build and operate the pipeline, and a positive final investment decision (**FID**) for the Kitimat LNG project, we expect the Merrick Mainline to be in service in first quarter 2020.
Revenue Requirement Settlements	
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.

Date	Description of development
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 on equity (**ROE**) at 10.10 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 operating, maintenance and administrative (**OM&A**) costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We also requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application.
November 2013	The NEB approved the NGTL 2013 – 2014 Settlement and final 2013 rates, as filed, in November 2013.
October 2014	We reached a revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement included no changes to the ROE of 10.10 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount. The settlement was filed with the NEB in October 2014.
February 2015	We received NEB approval for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include continuation of the 2014 ROE of 10.10 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount that is based on an escalation of 2014 actual costs.
Canadian Mainline	
May 2012	We received NEB approval to build new pipeline facilities to provide Ontario and Québec 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.
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016.
Tolls and Tariff Applications and LDC Settlement	
March 2013	We received the NEB decision on our Canadian Restructuring Proposal application to change the business structure and the terms and conditions of service for the Canadian Mainline. The NEB decision established a Toll Stabilization Account (**TSA**) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five-year term of the decision. The NEB decision also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances is if the TSA balance becomes positive, which occurred in 2013.
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 proposed to establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculated tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also included an incentive mechanism that 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 would have enabled the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement was intended to provide a market driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retained pricing flexibility for discretionary services and implemented certain tariff changes and new services as required by the terms of the settlement.

Date	Description of development
March 2014	The NEB responded to the LDC Settlement application we filed in December 2013. The NEB did not approve the application as a settlement but allowed us the option to continue with the application as a contested tolls application, amend the application or terminate the processing of the application. We amended the application with additional information.
May 2014	The NEB released a Hearing Order that set out a hearing process and schedule for the 2015 – 2030 Mainline Tolls and Tariff Application that incorporates the LDC Settlement. The hearing concluded in September 2014.
November 2014	The NEB approved the Canadian Mainline's 2015 – 2030 Tolls and Tariff Application. The application reflected components of the LDC Settlement. The approval of this application provides a long-term commercial platform for both the Canadian Mainline and its shippers with a known toll design for 2015 to 2020 and certain parameters for a toll-setting methodology up to 2030. The platform balances the needs of our shippers while at the same time ensuring a reasonable opportunity to recover the capital from our existing facilities and any new facilities required to serve existing and new markets. Highlights of the approved application include our commitment to add increased pipeline capacity that allows eastern Canadian markets more access to Dawn and Niagara area supplies; renewal provisions that will give us the tools to gain more certainty over capacity requirements; fixed price tolls on one-year and longer firm transportation service; continued pricing discretion for shorter term and interruptible service; a known revenue requirement along with an incentive sharing mechanism that targets a return of 10.10 per cent on a deemed common equity of 40 per cent, with a possible range of outcomes from 8.70 per cent to 11.50 per cent; and the continued use of a deferral account that compensates for the differences between actual revenues and the fixed toll arrangement, plus an agreement that any overall variance in revenues for the 2015-2020 period is assigned to the eastern area shippers for the period beyond 2020.
Eastern Mainline Project	
May 2014	We filed a project description with the NEB for the Eastern Mainline Project.
October 2014	We filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario (**Eastern Mainline Project**). The new facilities are a result of the proposed transfer of a portion of the Canadian Mainline capacity from natural gas service to crude oil service as part of our Energy East Pipeline and an open season that closed in January 2014. The $1.5 billion capital project will add 0.6 Bcf/d of new capacity in the Eastern Triangle segment of the Canadian Mainline and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments. The project is contingent upon the Energy East Pipeline and is subject to regulatory approvals expected to be issued simultaneously with regulatory approvals for the Energy East Pipeline. The project is expected to be in service by second quarter 2017.
Other Canadian Mainline Expansions	
November 2014	In addition to the Eastern Mainline Project, we have executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new facilities, or modifications to existing facilities with a total capital cost estimate of $475 million with expected in-service dates between November 2015 and November 2016. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in eastern Canada.
U.S. Pipelines	
Bison Pipeline	
July 2013	We sold an additional 45 per cent interest in each of Gas Transmission Northwest LLC (**GTN**) and Bison Pipeline LLC (**Bison**) to TC PipeLines, LP (**TCLP**) for an aggregate purchase price of US$1.05 billion. We continued to hold a 30 per cent direct ownership interest in both pipelines.
October 2014	We closed the sale of our remaining 30 per cent interest in Bison to TCLP for cash proceeds of US$215 million.
GTN Pipeline	
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.
November 2014	We announced an offer to sell the remaining 30 per cent interest in GTN to TCLP. Subject to the satisfactory negotiation of terms and TCLP's board approval, the transaction is expected to close in late first quarter 2015. We continue to hold a 28.3 per cent interest in TCLP for which we are the General Partner.
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 (**TCO**), allowing TCO 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	TCO began commercial operations.
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 project substantially increases our ability to receive gas on ANR's Southeast Main Line (**SEML**) from the Utica/Marcellus shale areas.

Date	Description of development
March 2014	We have secured nearly 2.0 Bcf/d of firm natural gas transportation commitments for existing and expanded capacity on ANR Pipeline's SEML. The capacity sales and expansion projects include reversing the Lebanon Lateral in western Ohio, additional compression at Sulphur Springs, Indiana, expanding the Rockies Express pipeline interconnect near Shelbyville, Indiana and 600 MMcf/d of capacity as part of a reversal project on the SEML. Capital costs associated with the ANR System expansions required to bring the additional capacity to market are currently estimated to be US$150 million. The capacity was subscribed at maximum rates for an average term of 23 years with approximately 1.25 Bcf/d of new contracts beginning service in late 2014. These secured contracts on the SEML will move Utica and Marcellus shale gas to points north and south on the system. ANR is also assessing further demand from our customers to transport natural gas from the Utica/Marcellus formation, which is expected to result in incremental opportunities to enhance and expand the system.
Greak Lakes	
November 2013	Great Lakes received Federal Energy Regulatory Commission (**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.
Mexican Pipelines	
Tamazunchale Pipeline Extension Project	
February 2012	We signed a contract with the Comisión Federal de Electricidad (Mexico) (**CFE**) for the Tamazunchale Pipeline Extension project. Engineering, procurement and construction contracts were signed and construction related activities began.
November 2014	Construction of the US$600 million extension was completed. Delays from the original service commencement date in March 2014 were attributed primarily to archeological findings along the pipeline route. Under the terms of the transportation service agreement, these delays were recognized as a force majeure with provisions allowing for collection of revenue from the original service commencement date.
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 miles), 30-inch pipeline with a capacity of 670 MMcf/d and an estimated cost of US$1 billion that will deliver gas to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico.
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 miles), 24-inch pipeline running from El Oro to Mazatlan, within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million.
Fourth Quarter 2014	Permitting, engineering, and construction 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.
Guadalajara	
First Quarter 2013	The compressor station went into service.
International Gas Pipelines	
Gas-Pacifico/INNERGY sale	
November 2014	We closed the sale of our 30 per cent equity interests in Gas Pacifico/INNERGY at a price of $9 million. This sale marks our exit from the Southern Cone region of South America.
LNG Pipeline Projects	
Coastal GasLink	
June 2012	We were selected to design, build, own and operate the proposed Coastal GasLink. The 670 km (416 miles) pipeline is expected to have an initial capacity of 1.7 Bcf/d and will transport natural gas from the Montney gas producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG export facility near Kitimat, B.C.
January 2014	We filed the Environmental Assessment Certificate (**EAC**) application with the B.C. Environmental Assessment Office (**EAO**). We focused on community, landowner, government and Aboriginal 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 FID 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.

Date	Description of development
March 2014	The 180-day EAO public review period began and included a 45-day public comment period. The B.C. Oil and Gas Commission (**OGC**) application was filed, together with an addendum to the B.C. Environmental Assessment application to capture recent route refinements. We began updating field work along the pipeline route to support the regulatory applications and refine the capital cost estimates in the second quarter.
October 2014	The EAO issued an EAC for Coastal GasLink. In 2014, we also submitted applications to the OGC for the permits required under the *Oil and Gas Activities Act* to build and operate Coastal GasLink. Regulatory review of those applications is progressing on schedule, with permit decisions anticipated in first quarter 2015. We are currently continuing our engagement with Aboriginal groups and stakeholders along the pipeline route and are progressing detailed engineering and construction planning work to support the regulatory applications and refine the capital cost estimates. Pending the receipt of all required regulatory approvals and a positive FID from our customer, construction is anticipated in 2016, with an in-service date by the end of the decade. Should the project not proceed, our project costs (including AFUDC) are fully recoverable.
Prince Rupert Gas Transmission (PRGT)	
January 2013	We were selected to design, build, own and operate the proposed 750 km (466 miles) 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 were focused on Aboriginal, community, landowner and government engagement as the PRGT advances through the regulatory process with the EAO. We continued to refine our study corridor based on consultation and detailed studies to date.
April 2014	The EAC application was submitted to the EAO for a completeness review and the application was filed with the OGC. The EAC application was subsequently deemed complete by the EAO. The EAO initiated a 180-day review period which included a 45-day public comment period that was completed in July 2014.
November 2014	We received an EAC from the EAO. We have submitted our pipeline permit applications to the OGC for construction of the pipeline and anticipate receiving these permits in first quarter 2015. We have made significant changes to the project route since first announced, increasing it by 150 km (93 miles) to 900 km (559 miles), taking into account Aboriginal and stakeholder input. We continue to work closely with Aboriginal groups and stakeholders along the proposed route to create and deliver appropriate benefits to all impacted groups. We concluded a benefits agreement with the Nisga' a First Nation to allow 85 km (52 miles) of the proposed natural gas pipeline to run through Nisga'a Lands.
December 2014	Our customer announced the deferral of an FID. We continue to work with our contractors to refine capital cost estimates for the project. Once the permitting process with the OGC is complete, and Pacific NorthWest LNG secures the necessary regulatory approvals and proceeds with a positive FID, we will be in a position to begin construction. All costs would be fully recoverable should the project not proceed. The deferral of an FID past the end of 2014 has resulted in a deferral of the expected in-service date for the pipeline. The in-service date will depend on when our customer receives the necessary regulatory approvals and is in a position to make an FID.
Alaska	
March 2012	Three major North Slope producers (the **ANS Producers**), along with us through participation in the Alaska LNG Project, announced agreement on a work plan aimed at commercializing North Slope natural gas resources through an LNG option.
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.
April 2014	The State of Alaska passed new legislation to provide a framework for us, the ANS Producers, and the Alaska Gasline Development Corp. (**AGDC**) to advance the development of an LNG export project.
June 2014	We executed an agreement with the State of Alaska to abandon the previous Alaska to Alberta project governance and framework and executed a new precedent agreement where we will act as the transporter of the State's portion of natural gas under a long-term shipping contract in the Alaska LNG Project. We also entered into a Joint Venture Agreement with the three major ANS Producers and AGDC to commence the pre-front end engineering and design (**pre-FEED**) phase of Alaska LNG Project. The pre-FEED work is anticipated to take two years to complete with our share of the cost to be approximately US$100 million. The precedent agreement also provides us with full recovery of development costs in the event the project does not proceed.
July 2014	The ANS Producers filed an export permit application with the U.S. Department of Energy for the right to export 20 million tonnes per annum of liquefied natural gas for 30 years.
September 2014	The FERC approved the National Environmental Policy Act (**NEPA**) pre-file request jointly made by us, the three major ANS Producers and AGDC. This approval triggers the NEPA environmental review process, which includes a series of community consultations.

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

DEVELOPMENTS IN THE LIQUIDS PIPELINES BUSINESS

Date	Description of development
Keystone Pipeline System	
February 2012	We announced that what had previously been the Cushing to U.S. Gulf Coast section of the Keystone Pipeline System has its own independent value to the marketplace, and that we plan to build it as a stand alone pipeline which is not part of the Keystone XL Presidential Permit application.
May 2012	We filed revised fixed tolls for the second section of the Keystone Pipeline System extending from Steele City, Nebraska to Cushing, Oklahoma, with both the NEB and the FERC. The revised tolls, which reflect the final project costs of the Keystone Pipeline System, became effective in July 2012.
January 2014	We finished constructing the 780 km (485 miles) 36-inch pipeline of the Gulf Coast extension of the Keystone Pipeline System from Cushing, Oklahoma to the U.S. Gulf Coast, and crude oil transportation service on the project began. We projected an average pipeline capacity of 520,000 Bbl/d for the first year of operation. The completion of the Gulf Coast extension in January 2014 expanded the Keystone Pipeline System to a 4,247 km (2,639 miles) pipeline system that transports crude oil from Hardisty, Alberta, to markets in the U.S. Midwest and the U.S. Gulf Coast. To date, the Keystone Pipeline System has delivered more than 830 million barrels of crude oil from Canada to the U.S.
Cushing Marketlink	
October 2012	We commenced construction on the Cushing Marketlink 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.
September 2014	Construction was completed.
Houston Lateral and Terminal	
Fourth Quarter 2014	Construction continues on the 77 km (48 miles) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in the second half of 2015.
Keystone XL	
February 2012	We sent a letter to the U.S. Department of State (**DOS**) informing the DOS that we planned to file a Presidential Permit application in the near future for Keystone XL. We also informed the DOS that the Cushing to U.S. Gulf Coast portion of Keystone XL 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.
March 2013	The DOS released its Draft Supplemental Environmental Impact Statement for Keystone XL. The impact statement reaffirmed construction of the 830,000 Bbl/d Keystone XL project would not result in any significant impact to the environment.
January 2014	The DOS released its Final Supplemental Environmental Impact Statement (**FSEIS**) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is unlikely to significantly impact the rate of extraction in the oil sands and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more 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 Keystone XL.
April 2014	The DOS announced that the national interest determination period has been extended indefinitely to allow them to consider the potential impact of the Nebraska portion of the pipeline route.
September 2014	Nebraska's Attorney General filed an appeal which was heard by the Nebraska State Supreme Court. We filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (**PUC**). This certification confirms that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted continue to be satisfied. The formal hearing for the certification is scheduled for May 2015.

Date	Description of development
January 2015	The Nebraska State Supreme Court vacated the lower court's ruling that the law was unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remains valid. Landowners have filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds.
January 2015	The DOS reinitiated the national interest review and requested the eight federal agencies, with a role in the review, to complete their consideration of whether Keystone XL serves the national interest and to provide their views to the DOS by February 2, 2015.
February 2015	The U.S. Environmental Protection Agency (**EPA**) posted a comment letter to its website suggesting that, among other things, the FSEIS issued by the DOS has not fully and completely assessed the environmental impacts of Keystone XL and that, at lower oil prices, Keystone XL may increase the rates of oil sands production and greenhouse gas emissions. We sent a letter to the DOS refuting these and other comments in the EPA letter but also offering to work with the DOS to ensure it has all the relevant information to allow it to reach a decision to approve Keystone XL. The timing and ultimate approval of Keystone XL remain uncertain. In the event the project does not proceed as planned, we would reassess and reduce its carrying value to its recoverable amount if necessary and appropriate. The estimated capital costs for Keystone XL are expected to be approximately US$8.0 billion. As of December 31, 2014, we had invested US$2.4 billion in the project and have also capitalized interest in the amount of $0.4 billion.
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.
Fourth Quarter 2014	The Keystone Hardisty Terminal will be constructed in conjunction with Keystone XL and is expected to be completed approximately two years from the date the Keystone XL permit is received.
Energy East Pipeline	
April 2013	We announced that we were holding an open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets. The open season followed a successful expression of interest phase and discussions with prospective shippers.
August 2013	We announced that we were moving forward with the 1.1 million Bbl/d Energy East Pipeline as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. We began Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning.
March 2014	We filed the project description for the Energy East Pipeline with the NEB. This was the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline.
October 2014	We filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline and terminal facilities with the NEB. 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 by the end of 2018.
December 2014	The Energy East Pipeline includes a proposed marine terminal near Cacouna, Québec which would be adjacent to a beluga whale habitat. The Committee on the Status of Endangered Wildlife in Canada recommended that beluga whales be placed on the endangered species list. As a result, we have made the decision to halt any further work at Cacouna and will be analyzing the recommendation, assessing any impacts to the project and reviewing all viable options. We intend to make a decision on how to proceed by the end of first quarter 2015. The 1.1 million Bbl/d Energy East Pipeline received approximately one million Bbl/d of firm, long-term contracts to transport crude oil from western Canada that were secured during binding open seasons.
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 a 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 was proceeding with the Fort Hills oil sands mining project and that it expected to begin producing crude oil in 2017.
July 2014	The AER issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has started on the $900 million, 90 km (56 miles) pipeline to transport bitumen and diluent between the Fort Hills mine site and Suncor's terminal located north of Fort McMurray, Alberta. We currently expect the pipeline to be ready for service in 2017.

Date	Description of development
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.
October 2013	We filed a permit application for the pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.
February 2014	The application for the terminal facility was approved by the AER.
October 2014	Construction commenced on the terminal. The Heartland Pipeline is a 200 km (125 miles) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta. TC Terminals is a terminal facility in the Heartland industrial area north of Edmonton, Alberta. The pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have initial storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined estimated cost of $900 million and are expected to be placed in service in late 2017.
Grand Rapids Pipeline	
October 2012	We announced that we had entered into binding agreements with a partner to develop the Grand Rapids Pipeline, a 460 km (287 miles) crude oil and diluent pipeline system connecting the producing area northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland, Alberta region. Our partner has also entered into a long-term transportation service contract in support of the Grand Rapids Pipeline. Along with our partner, we will each own 50 per cent of the project and we will operate the system.
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.
October 2014	The AER issued a permit approving our application to construct and operate the Grand Rapids Pipeline. Construction has commenced with initial crude oil transportation planned in 2016.
Upland Pipeline	
November 2014	We completed a successful binding open season for the Upland Pipeline. The $600 million pipeline would provide crude oil transportation from, and between multiple points in North Dakota and interconnect with the Energy East Pipeline System at Moosomin, Saskatchewan. Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2018. The commercial contracts we have executed for Upland Pipeline are conditioned on Energy East proceeding.

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

DEVELOPMENTS IN THE ENERGY BUSINESS

Canadian Power

Date	Description of development
Ontario Solar	
June 2013	We completed the acquisition of the first facility for $55 million as per our December 2011 agreement, pursuant to which we agreed to buy nine Ontario solar generation facilities (combined capacity of 86 megawatts (**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 Feed-in Tariff (**FIT**) contracts with the IESO.
September 2013	We completed the acquisition of two additional solar facilities for $99 million.
December 2013	We completed the acquisition of an additional solar facility for $62 million.
September 2014	We completed the acquisition of three additional solar facilities for $181 million.
December 2014	We acquired an additional solar facility for $60 million. Our total investment in the eight solar facilities is $457 million.
Napanee	
December 2012	We signed a contract with the Ontario Power Authority (**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.
January 2015	We began construction activities on the power plant. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018. Production from the facility is fully contracted with the Independent Electricity System Operator (**IESO**).
Bécancour	
June 2012	Hydro-Québec Distribution (**Hydro-Québec**) notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013. Under the original agreement, Hydro-Québec had the option to extend the suspension on an annual basis until such time as regional electricity demand levels recover.
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.
May 2014	We received final approval from the Régie de l'énergie for the December 2013 amendment to the original suspension agreement with Hydro-Québec. In addition, Hydro-Québec exercised its option in the amended suspension agreement to extend suspension of all electricity generation to the end of 2017, and requested further suspension of generation to the end of 2018. We continue to receive capacity payments while generation is suspended.
Cancarb Limited and Cancarb Waste Heat Facility	
January 2014	We announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility.
April 2014	The sale of Cancarb Limited and its related power generation facility, closed for gross proceeds of $190 million. We recognized a gain of $99 million, net of tax, in second quarter 2014.
Bruce Power	
March 2012	Bruce Power received authorization from the Canadian Nuclear Safety Commission to power up the Bruce A Unit 2 reactor.
May 2012	An incident occurred within the Bruce A Unit 2 electrical generator on the non-nuclear side of the plant which delayed the synchronization of Bruce A 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 Bruce A Unit 3 to service after completing the $300 million West Shift Plus life extension outage, which began in 2011.
August 2012	We confirmed that Bruce Power's force majeure claim to the OPA related to the Bruce A Unit 2 had been accepted. 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.

Date	Description of development
October 2012	Bruce A Units 1 and 2 were returned to service following the completion of their refurbishment.
November 2012	Both Bruce A Units 1 and 2 have operated at reduced output levels following their return to service, and Bruce Power took Bruce A Unit 1 offline for an approximate one month maintenance outage.
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 Bruce A Unit 4 to operate until at least 2021.
March 2014	Cameco Corporation sold its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We are considering our option to increase our Bruce B ownership percentage.
Fourth Quarter 2014	New Canadian federal legislation is expected to come into force in 2015 respecting the determination of liability and compensation for a nuclear incident in Canada resulting in personal injuries and damages. This proposed legislation will replace existing legislation which currently provides that the licensed operator of a nuclear facility has absolute and exclusive liability and limits the liability to a maximum of $75 million. The proposed new law is fundamentally consistent with the existing regime although the maximum liability will increase to $650 million and increase in increments over three years to a maximum of $1 billion. The operator will also be required to maintain financial assurances such as insurance in the amount of the maximum liability. Our indirect subsidiary owns one third of the common shares of Bruce Power Inc., the licensed operator of Bruce Power, and as such Bruce Power Inc. is subject to this liability in the event of an incident as well as the legislation's other requirements.
Sundance	
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.
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.
Cartier Wind	
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.
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 (**Bcf**) of working gas storage capacity to our existing portfolio in Alberta.
U.S. Power	
Ravenswood	
September 2014	The 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, net of deductibles, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings, although the recording of earnings may not coincide with lost revenues due to timing of the anticipated insurance proceeds. The unit is expected to be back in service in first half 2015.
New York power business	
June 2012	In 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. In 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.

Date	Description of development
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 not owned by us 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 put upward pressure on capacity auction prices since December 2012. 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. This new assumption has the potential to negatively affect Zone J 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.
Fourth Quarter 2014	Average New York Zone J spot capacity prices were approximately 27 per cent higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014.
Natural Gas Storage	
April 2014	We terminated a 38 Bcf long-term natural gas storage contract in Alberta with Niska Gas Storage. The contract contained provisions allowing for possible early termination. As a result, we recorded an after tax charge of $32 million in 2014. We have re-contracted for new natural gas storage services in Alberta with Niska Gas Storage starting May 1, 2014 for a six-year period and a reduced average volume.

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

Business of TransCanada

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Liquids Pipelines and Energy. At Year End and for the year then ended, Natural Gas Pipelines accounted for approximately 48 per cent of revenues and 46 per cent of our total assets, Liquids Pipelines accounted for approximately 15 per cent of revenues and 27 per cent of our total assets' and Energy accounted for approximately 37 per cent of revenues and 24 per cent of our total assets. The following table shows our revenues from operations by segment, classified geographically, for the years ended December 31, 2014 and 2013.

Revenues from operations (millions of dollars)	**2014**	**2013**
Natural Gas Pipelines		
Canada – Domestic	$2,672	$2,718
Canada – Export[1]	881	598
United States	1,163	1,069
Mexico	197	112
	4,913	4,497
Liquids Pipelines		
Canada – Domestic	–	–
Canada – Export[1]	432	399
United States	1,115	725
	1,547	1,124
Energy[2]		
Canada – Domestic	1,349	1,941
Canada – Export[1]	1	–
United States	2,375	1,235
	3,725	3,176
Total revenues[3]	$10,185	$8,797

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

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

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. 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	24,525 km (15,239 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%
Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
U.S. pipelines			
ANR Pipeline	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
Gas Transmission Northwest (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 49.8 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	49.8%
Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 66.7 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	66.77%
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 a third-party pipeline on the California/Mexico border. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
Northern Border	2,265 km (1,407 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 14.2 per cent of the system through our 28.3 per cent interest in TC PipeLines, LP	14.2%

	length	description	effective ownership
U.S. pipelines			
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 markets in northeastern California and northwestern Nevada. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
TC Offshore	958 km (595 miles)	Gathers and transports natural gas within the Gulf of Mexico with subsea pipeline and seven offshore platforms to connect in Louisiana with our ANR pipeline system.	100%
Mexican pipelines			
Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
Tamazunchale	365 km (227 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to to El Sauz, Queretaro	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%
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	25%
Coastal GasLink	670 km* (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
Prince Rupert Gas Transmission	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
North Montney Mainline	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project	100%
Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
Eastern Mainline	245 km* (152 miles)	Various pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project	100%
** NGTL 2016/17 Facilities**	540 km* (336 miles)	The expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests on the NGTL System	100%

* Pipe lengths are estimates as final route is still under design
** Facilities are not shown on the map

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

LIQUIDS PIPELINES BUSINESS

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

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

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

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

REGULATION OF THE NATURAL GAS AND LIQUIDS PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

The Canadian Mainline, NGTL System and 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. Generally, Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years. The Canadian Mainline, however, operates under a fixed toll arrangement for its longer term firm transportation service and has the flexibility to price its shorter term and discretionary services in order to maximize its revenue. Further information relating to the decision from the NEB regarding the Canadian Restructuring Proposal as well as the LDC Settlement can be found in the *General Developments of the business – Developments in the Natural Gas Pipelines business – Canadian Mainline, Tolls and Tariff Applications (LDC Settlement)* 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 ROE, and any incentive earnings.

Natural Gas Pipelines Projects

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

Liquids Pipelines

The NEB regulates the terms and conditions of service, including rates, facilities and the physical operation of the Canadian portion of the Keystone Pipeline System.

Liquids Pipelines Projects

TC Terminals, Northern Courier Pipeline, and Grand Rapids Pipeline were approved by the AER in February, July and October 2014 respectively. All three projects are currently under construction. The Heartland Pipeline application is currently under regulatory review by the AER. The AER administers approvals required to construct and operate the pipelines and associated facilities in accordance with *Directive 56*, approvals to obtain land access under the *Public Land Act,* and environmental approvals under the *Environmental and Protection Enhancement Act*.

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

United States

Natural Gas Pipelines

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

Liquids Pipelines

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

Mexico

Natural Gas Pipelines

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

ENERGY BUSINESS

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

We own, control or are developing generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our power business in the U.S. is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low cost baseload generation, while others are 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 8,037 MW of power generation capacity (including facilities under construction)					
Western Power 2,609 MW of power supply in Alberta and the western U.S.					
Bear Creek	80	natural gas	Cogeneration plant	Grande Prairie, Alberta	100%
Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
Coolidge(1)	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
Sheerness PPA	756	coal	Output contracted under PPA	Hanna, Alberta	100%
Sundance A PPA	560	coal	Output contracted under PPA	Wabamun, Alberta	100%
Sundance B PPA (Owned by ASTC Power Partnership(2))	353(3)	coal	Output contracted under PPA	Wabamun, Alberta	50%
Eastern Power 2,939 MW of power generation capacity (including facilities under construction)					
Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
Cartier Wind	365(3)	wind	Five wind power projects	Gaspésie, Québec	62%
Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
Portlands Energy	275(3)	natural gas	Combined-cycle plant	Toronto, Ontario	50%
Ontario Solar	76	solar	Eight solar facilities	Southern Ontario and New Liskeard, Ontario	100%
Bruce Power 2,489 MW of power generation capacity through eight nuclear power units					
Bruce A	1,467(3)	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
Bruce B	1,022(3)	nuclear	Four operating reactors	Tiverton, Ontario	31.6%

	generating capacity (MW)	type of fuel	description	location	ownership
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%
Under construction					
Napanee	900	natural gas	Combined-cycle plant	Greater Napanee, Ontario	100%

(1) Located in Arizona, results reported in Canadian Power – Western Power.
(2) We have a 50 per cent interest in ASTC Power Partnership, which has a PPA for production from the Sundance B power generating facilities.
(3) 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 the ASTC Power Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

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

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

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

	Type of contract	With	Expires
Bécancour(1)	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	IESO	2030
Portlands Energy	20-year Clean Energy Supply contract	IESO	2029
Ontario Solar(2)	20-year FIT contracts	IESO	2032-2034

(1) Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.
(2) We acquired four facilities in 2013 and an additional four facilities in 2014.

Assets currently under construction are as follows:

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

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 6,059 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	3,186
Western Canada (excluding Calgary)	497
Eastern Canada	315
Houston	576
U.S. Midwest	464
U.S. Northeast	451
U.S. Southeast/Gulf Coast (excluding Houston)	319
U.S. West Coast	86
Mexico and South America	165
Total	6,059

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Health, Safety and Environment committee of TransCanada's Board of Directors (the **Board**) oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our 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 that 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 and operational risk management on a quarterly basis. It receives detailed reports on:

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

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

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 2014 continued to meet or exceed most industry benchmarks.

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

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

Social Policies

TransCanada has a number of policies, guiding principles and practices in place to help manage 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. All employees (including executive officers) and directors must certify their compliance with the Code every year. The Code is based on the Company's four core values of integrity, collaboration, responsibility and innovation, which guide the interaction between and among the Company's employees and contractors, and serve as a standard for us in our dealings with all stakeholders.

Our approach to 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, Liquids Pipelines – Business Risks, Energy – Business Risks* and *Other information – Risks and risk management* sections, which sections of the MD&A are incorporated by reference into this AIF.

Dividends

Our Board has not adopted a formal dividend policy. The Board reviews the financial performance of TransCanada quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, our payment of dividends is primarily funded from dividends 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.

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

	2014	2013	2012
Dividends declared on common shares	$1.92	$1.84	$1.76
Dividends declared on Series 1 preferred shares	$1.15	$1.15	$1.15
Dividends declared on Series 2 preferred shares(1)	–	–	–
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(2)	$1.00	$0.91	–
Dividends declared on Series 9 preferred shares(3)	$1.09	–	–

(1) Issued December 31, 2014. TransCanada announced on December 31, 2014 that 12,501,577 of its 22,000,000 Series 1 preferred shares were tendered for conversion effective December 31, 2014 on a one-for-one basis into Series 2 preferred shares. As a result of the conversion, TransCanada had 9,498,423 Series 1 preferred shares and 12,501,577 Series 2 preferred shares issued and outstanding as at December 31, 2014. The Series 1 preferred shares will pay on a quarterly basis, for the five-year period beginning on December 31, 2014, as and when declared by the Board, a fixed dividend based on an annual rate of 3.266 per cent. The Series 2 preferred shares will pay a floating quarterly dividend for the five-year period beginning on December 31, 2014, as and when declared by the Board. The floating quarterly dividend rate for the Series 2 preferred shares for the first quarterly floating rate period (being the period from December 31, 2014 to but excluding March 31, 2015) is an annual rate of 2.815 per cent which will be reset every quarter.
(2) Issued March 4, 2013.
(3) Issued January 20, 2014.

We increased the quarterly dividend on our outstanding common shares by eight per cent to $0.52 per share for the quarter ending March 31, 2015.

Description of capital structure

SHARE CAPITAL

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 708,662,996 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.

First Preferred Shares	Issued and Outstanding	Convertible to
Series 1 preferred shares	9,498,423	Series 2 preferred shares
Series 2 preferred shares(1)	12,501,577	Series 1 preferred shares
Series 3 preferred shares	14,000,000	Series 4 preferred shares
Series 5 preferred shares	14,000,000	Series 6 preferred shares
Series 7 preferred shares	24,000,000	Series 8 preferred shares
Series 9 preferred shares(2)	18,000,000	Series 10 preferred shares

(1) Issued upon conversion of Series 1 preferred shares on December 31, 2014.
(2) 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, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the directors if TransCanada fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors.

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

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

The holders of Series 2, 4, 6, 8 and 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, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series 1, 3, 5, 7 and 9 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 2, 4, 6, 8 and 10 preferred shares are redeemable by TransCanada in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

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

Series of First Preferred Shares	Initial Redemption Date	Redemption/Conversion Dates	Spread (%)
Series 1 preferred shares	–	December 31, 2019 and every fifth year thereafter	1.92
Series 2 preferred shares	December 31, 2014	December 31, 2019 and every fifth year thereafter	1.92
Series 3 preferred shares	–	June 30, 2015 and every fifth year thereafter	1.28
Series 4 preferred shares	June 30, 2015	June 30, 2020 and every fifth year thereafter	1.28
Series 5 preferred shares	–	January 30, 2016 and every fifth year thereafter	1.54
Series 6 preferred shares	January 30, 2016	January 30, 2021 and every fifth year thereafter	1.54
Series 7 preferred shares	–	April 30, 2019 and every fifth year thereafter	2.38
Series 8 preferred shares	April 30, 2019	April 30, 2024 and every fifth year thereafter	2.38
Series 9 preferred shares	–	October 30, 2019 and every fifth year thereafter	2.35
Series 10 preferred shares	October 30, 2019	October 30, 2024 and every fifth year thereafter	2.35

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

Second preferred shares

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

Credit ratings

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

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

Each of the Company and TCPL paid fees to each of DBRS, Moody's and S&P for the credit ratings rendered 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 10 rating categories and indicates good credit quality. The capacity for payment of short-term financial obligations as they fall due is substantial. The overall strength is not as favourable as higher rating categories. Short-term debt rated R-1 (low) may be vulnerable to future events, but qualifying negative factors are considered manageable. The A (low) rating assigned to TCPL's senior unsecured debt is in the third highest of ten categories for long-term debt. Long-term debt rated A is good credit quality. The capacity for the payment of 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 long-term debt rated BBB 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 appended to each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and a modifier 3 indicates a ranking in the lower end of that generic rating category. The A3 rating assigned to TCPL's senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are judged to be upper medium-grade and are subject to low credit risk. The 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 higher within the Baa rating category with a modifier of 1 as opposed to the modifier of 2 on the preferred shares. Obligations rated Baa are judged to be medium-grade and are subject to moderate credit risk and, as such, may possess certain speculative characteristics.

S&P

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

Market for securities

TransCanada's common shares are listed on the TSX and the New York Stock Exchange (**NYSE**) under the symbol TRP. Our Series 1, 2, 3, 5, 7 and 9 preferred shares have been listed for trading on the TSX since September 30, 2009, December 31, 2014, March 11, 2010, June 29, 2010, March 4, 2013 and January 20, 2014 under the symbols TRP.PR.A, TRP.PR.F, 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, 2, 3, 5, 7 and 9 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 2014	$58.18	$51.47	$57.10	39,181,474	$51.06	$44.40	$49.10	27,293,987
November 2014	$57.98	$53.87	$54.45	29,512,092	$51.44	$47.21	$48.16	27,196,711
October 2014	$58.03	$49.30	$55.55	46,346,061	$51.84	$43.71	$49.29	44,973,083
September 2014	$63.86	$56.74	$57.68	49,632,379	$58.40	$51.02	$51.53	47,530,203
August 2014	$58.74	$53.19	$58.43	25,578,084	$54.05	$48.78	$53.78	25,280,599
July 2014	$56.34	$50.38	$54.70	29,465,223	$52.27	$47.24	$50.17	15,367,685
June 2014	$51.45	$50.02	$50.93	20,404,127	$48.13	$45.72	$47.72	9,386,604
May 2014	$51.76	$50.41	$50.48	15,956,228	$47.52	$46.17	$46.65	9,026,941
April 2014	$51.89	$49.34	$51.08	22,553,336	$47.25	$44.78	$46.63	11,068,870
March 2014	$50.97	$48.50	$50.25	17,476,864	$45.65	$43.73	$45.52	9,005,406
February 2014	$50.24	$47.43	$48.74	18,422,252	$45.71	$42.73	$44.03	10,356,246
January 2014	$49.29	$47.14	$48.42	22,672,643	$45.81	$42.21	$43.44	12,501,327

PREFERRED SHARES

	Preferred Shares					
Month	Series 1	Series 2	Series 3	Series 5	Series 7	Series 9
December						
High	$21.50	$22.85	$18.49	$21.98	$25.55	$25.73
Low	$19.18	$22.41	$17.02	$18.61	$24.79	$25.00
Close	$21.20	$22.61	$17.92	$21.53	$25.28	$25.43
Volume Traded	1,886,935	37,025	511,512	488,294	350,740	345,413
November						
High	$22.29	–	$19.29	$22.48	$25.59	$25.69
Low	$21.40	–	$18.48	$21.55	$25.05	$25.20
Close	$21.50	–	$18.54	$21.86	$25.53	$25.56
Volume Traded	961,356	–	614,216	238,730	196,566	798,443
October						
High	$22.68	–	$19.53	$21.74	$25.33	$25.60
Low	$21.34	–	$18.48	$20.54	$24.76	$25.00
Close	$21.80	–	$18.95	$21.69	$25.12	$25.29
Volume Traded	801,630	–	229,370	312,713	156,322	291,498
September						
High	$23.19	–	$20.04	$22.88	$25.45	$25.68
Low	$22.30	–	$19.06	$21.23	$24.50	$24.77
Close	$22.61	–	$19.39	$21.44	$24.95	$25.05
Volume Traded	296,706	–	213,145	127,510	281,562	569,846
August						
High	$23.47	–	$20.27	$22.79	$25.50	$25.80
Low	$22.81	–	$19.56	$22.19	$25.20	$25.34
Close	$23.14	–	$19.72	$22.65	$25.45	$25.69
Volume Traded	150,425	–	150,841	91,404	257,107	215,759

Month	Preferred Shares Series 1	Series 2	Series 3	Series 5	Series 7	Series 9
July						
High	$23.59	–	$20.50	$22.65	$25.38	$25.55
Low	$23.10	–	$19.93	$22.07	$25.08	$25.26
Close	$23.40	–	$20.01	$22.45	$25.15	$25.47
Volume Traded	289,811	–	169,917	202,331	382,076	172,975
June						
High	$23.84	–	$20.48	$23.16	$25.24	$25.59
Low	$23.01	–	$20.02	$22.22	$24.35	$24.88
Close	$23.24	–	$20.35	$22.59	$25.24	$25.39
Volume Traded	330,251	–	371,671	133,102	213,689	161,055
May						
High	$24.48	–	$21.45	$23.40	$25.69	$25.68
Low	$23.16	–	$20.40	$22.71	$24.76	$25.02
Close	$23.16	–	$20.40	$23.01	$24.76	$25.11
Volume Traded	375,099	–	425,887	479,657	367,889	224,933
April						
High	$24.24	–	$20.94	$22.99	$25.53	$25.62
Low	$23.28	–	$20.19	$21.91	$24.73	$25.13
Close	$24.19	–	$20.89	$22.94	$25.53	$25.62
Volume Traded	731,585	–	332,360	826,978	406,590	1,109,855
March						
High	$23.61	–	$20.50	$22.71	$25.11	$25.27
Low	$23.00	–	$19.97	$21.75	$24.76	$24.99
Close	$23.23	–	$20.13	$21.93	$24.95	$25.17
Volume Traded	1,770,656	–	575,485	492,867	389,277	607,229
February						
High	$23.52	–	$20.47	$22.41	$25.00	$25.12
Low	$23.02	–	$20.11	$21.80	$24.60	$24.75
Close	$23.12	–	$20.39	$22.30	$24.97	$25.10
Volume Traded	244,713	–	357,933	502,010	430,852	969,637
January						
High	$24.47	–	$20.67	$22.42	$25.30	$24.99
Low	$23.10	–	$20.13	$21.56	$24.60	$24.74
Close	$23.28	–	$20.44	$22.11	$24.79	$24.78
Volume Traded	474,850	–	192,252	177,153	1,860,968	1,452,897

TCPL's cumulative redeemable first preferred shares, series Y, were listed on the TSX under the symbol TCA.PR.Y until their redemption on March 5, 2014.

SERIES Y PREFERRED SHARES

Month	Series Y (TCA.PR.Y) High ($)	Low ($)	Close ($)	Volume Traded
March 2014	$50.25	$50.24	$50.25	2,060
February 2014	$50.25	$50.13	$50.25	37,465
January 2014	$50.36	$49.85	$50.15	151,322

Directors and officers

As of February 12, 2015, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 441,744 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 12, 2015 (unless otherwise indicated), together with their jurisdictions of residence, all positions and offices held by them with TransCanada, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the Arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Kevin E. Benson Calgary, Alberta Canada	Corporate director. Director, Calgary Airport Authority from January 2010 to December 2013.	2005
Derek H. Burney[(1)], O.C. Ottawa, Ontario Canada	Senior strategic advisor, Norton Rose Fulbright (law firm). 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.	2005
The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Stein Monast L.L.P. (law firm). Director, Metro Inc. (food retail) since January 2001. Director, Royal Bank of Canada (chartered bank) from October 1991 to March 2014 and Chair, RBC Dexia Investors Trust until October 2011.	2002
Russell K. Girling[(2)] Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 2010. Chief Operating Officer from July 2009 to June 2010 and President, Pipelines from June 2006 to June 2010. Director, Agrium Inc. (agricultural) since May 2006.	2010
S. Barry Jackson 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
Paula Rosput Reynolds Seattle, Washington U.S.A.	President and Chief Executive Officer, PreferWest, LLC (business advisory group) since October 2009. Director, BAE Systems plc. (aerospace, defence, information security) since April 2011 and Delta Air Lines, Inc. (airline) since August 2004. Director, Anadarko Petroleum Corporation (oil and gas, exploration and production) from August 2007 to May 2014.	2011
John Richels Nichols Hills, Oklahoma U.S.A.	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)] Naples, 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. Director, United States Enrichment Corporation (basic materials, nuclear) from December 2011 to October 2012.	2013
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Pengrowth Energy Corporation (oil and gas, exploration and production) since December 2010. Director, and Audit and Governance committee Chair, Canadian Energy Services & Technology Corp. (chemical, oilfield services) since January 2010. Director, 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.	2006

Name and place of residence	Principal occupation during the five preceding years	Director since
Siim A. Vanaselja(4) Westmount, Québec Canada	Corporate Director. Executive Vice-President and Chief Financial Officer of BCE Inc. (telecommunications and media) since January 2001. Director, Bell Media since March 2011, Bell Aliant Regional Communication Inc. since July 2008, BCE Ventures Inc. since April 2002 and Bimcor Inc. since November 1996. Director, Great-West Lifeco Inc. since May 2014. Director and Audit committee Chair, Maple Leaf Sports and Entertainment Ltd. (sports, property management) since August 2012. Director, CH Group Limited Partnership from August 2009 to August 2012.	2014
Richard E. Waugh Calgary, Alberta Canada	Corporate director. Former Deputy Chairman, President and Chief Executive Officer, The Bank of Nova Scotia (**Scotiabank**) (chartered bank) until January 2014. Director, Catalyst Inc. (non-profit) from February 2007 to November 2013 and Chair, Catalyst Canada Inc. Advisory Board from February 2007 to October 2013.	2012

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

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

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

(4) Mr. Vanaselja joined the Board effective May 2, 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 12, 2015, are identified below. Ms. Reynolds was appointed as the Chair of the Human Resources committee effective May 2, 2014.

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 (Chair)		✓		✓
Paula Rosput Reynolds			✓	Chair
John Richels			✓	✓
Mary Pat Salomone	✓		✓	
D. Michael G. Stewart	✓		Chair	
Siim A. Vanaselja	✓	✓		
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. 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.
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 since July 2009.
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).
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.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
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).
Alexander J. Pourbaix	Executive Vice-President and President, Development	Prior to March 2014, President, Energy and Oil Pipelines. Prior to July 2010, President, Energy Division since June 2006 and Executive Vice-President, Corporate Development since July 2009.
William C. Taylor	Executive Vice-President and President, Energy	Prior to March 2014, Senior Vice-President, U.S. and Canadian Power. Prior to May 2013, Senior Vice-President, Eastern Power. Prior to July 2010, Vice-President and General Manager, U.S. Northeast Power since May 2008 (TCPL).

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 (TCPL).
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, Law and Corporate Secretary	Prior to June 2014, Vice-President and Corporate Secretary. Prior to March 2012, Vice-President, Finance Law. Prior to January 2010, Vice-President, Corporate Development Law.
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 liquids through our pipeline systems. Transmission services on most of TransCanada's pipeline systems in Canada and the U.S. are subject to regulation and accordingly we generally cannot deny transportation services to a creditworthy shipper. The Governance committee monitors relationships among directors to ensure that business associations do not affect the Board's performance.

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

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

Affiliates

The Board 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, in each case, apply to foreign private issuers.

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

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

Audit committee

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

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The members of the Audit committee as of February 12, 2015 are Kevin E. Benson (Chair), Derek H. Burney, Mary Pat Salomone, D. Michael G. Stewart, and Siim A. Vanaselja. Richard E. Waugh attended the Audit committee meetings as an observer until he retired as Deputy Chairman of Scotiabank on January 31, 2014 and was a voting member of the committee from February 1 until May 2, 2014. Mr. Vanaselja was appointed as a member of the Audit committee effective May 2, 2014.

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. Vanaselja 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. He serves as a director of the Winter Sport Institute, and was the President and Chief Executive Officer of Laidlaw International, Inc. until October 2007. In prior years, he has held several executive positions including 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 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.

Siim A. Vanaselja

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

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)	2014	2013
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	$6.4
Audit-related fees • services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment plans	0.2	0.2
Tax fees • Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings	0.5	0.7
All other fees	–	–
Total fees	**$7.1**	**$7.3**

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.

Material contracts

TransCanada did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2014, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2014 which are still in effect as at the date of this AIF.

Interest of experts

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

Additional information

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

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
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	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes annual average assets in rate base as well as assets under construction
LNG	Liquefied natural gas
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Our investment in assets used to provide transportation services on our natural gas pipelines
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds using during construction
DRP	Dividend reinvestment plan
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)
DOS	Department of State (U.S.)
EPA	Environmental Protection Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
NEB	National Energy Board (Canada)
NYISO	New York Independent System Operator
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 quarterly, the report of the Chief Information Officer (or such other appropriate Company representative) on information security controls, education and awareness.

XII. Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external 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.