TransCanada Corporation

2015 Annual information form

February 10, 2016

Contents

Presentation of information

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

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

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

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

Forward-looking information

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

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

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

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

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

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

Assumptions

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

Risks and uncertainties

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

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC.

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

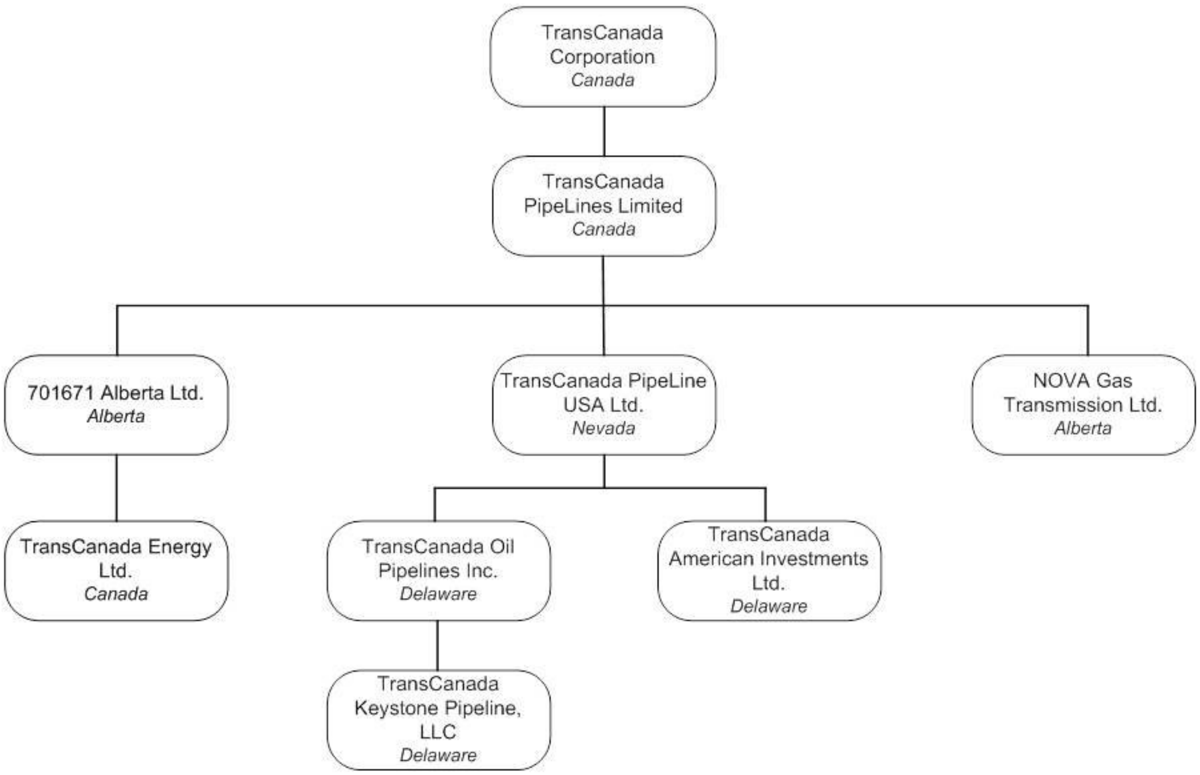
TransCanada Corporation

CORPORATE STRUCTURE

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

INTERCORPORATE RELATIONSHIPS

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



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

General development of the business

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

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

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

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

Date	Description of development
NGTL Revenue Requirement Settlements	
August 2013	We reached settlement of the NGTL System annual revenue requirement for the years 2013 and 2014 with shippers and other interested parties (the **NGTL 2013 – 2014 Settlement**). The settlement fixed the ROE at 10.10 per cent on 40 per cent deemed common equity, established an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixed the OM&A costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We also requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application.
November 2013	The NEB approved the NGTL 2013 - 2014 Settlement and final 2013 rates, as filed, in November 2013.
October 2014	We reached a revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement included no changes to the ROE of 10.10 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount. The settlement was filed with the NEB in October 2014.
February 2015	We received NEB approval for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include continuation of the 2014 ROE of 10.10 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount that is based on an escalation of 2014 actual costs.
December 2015	We reached a two-year revenue requirement agreement with customers and other interested parties on the annual costs, including return on equity and depreciation required to operate the NGTL System for 2016 and 2017. The agreement fixes the equity return at 10.1 per cent on 40 per cent deemed common equity, establishes depreciation at a forecast composite rate of 3.16 per cent and fixes OM&A costs at $225 million annually. An incentive mechanism for variances will enable NGTL to capture savings from improved performance and provide for the flow-through of all other costs, including pipeline integrity expenses and emissions costs. NGTL filed on December 1, 2015 with the NEB for approval of the agreement.
CANADIAN MAINLINE	
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016.
Mainline Settlement & Tolls and Tariff Applications and LDC Settlement	
March 2013	We received the NEB decision on our Canadian Restructuring Proposal application to change the business structure and the terms and conditions of service for the Canadian Mainline. The NEB decision established a Toll Stabilization Account (**TSA**) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five year term of the decision. The NEB decision also identified certain circumstances that would require a new tolls application prior to the end of the five year term. One of those circumstances is if the TSA balance becomes positive, which occurred in 2013. Subsequently, we filed a review and variance application with the NEB in May 2013, which was dismissed in June 2013 and the NEB set out a process to consider the tariff revisions.
July 2013	The NEB released its reasons for the dismissal of our review and variance application. Additional changes to the Canadian Mainline's tariff were considered by the NEB as a separate application which was heard in an oral hearing. We began implementation of the NEB decision related to the Canadian Restructuring Proposal. The implementation of the NEB decision was a key priority in 2013 and with the ability to price discretionary services at market prices we were able to essentially meet our overall cost of service requirements for 2013.
September 2013	The Canadian Mainline and the three largest Canadian local distribution companies (**LDCs**) entered into a settlement (**LDC Settlement**) which was filed with the NEB for approval in December 2013. The LDC Settlement proposed to establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculated tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also included an incentive mechanism that required a $20 million (after tax) annual contribution by us from 2015 to 2020, which could have resulted in a range of ROE outcomes from 8.70 per cent to 11.50 per cent. The LDC Settlement would have enabled the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement was intended to provide a market driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retained pricing flexibility for discretionary services and implemented certain tariff changes and new services as required by the terms of the settlement.
March 2014	The NEB responded to the LDC Settlement application we filed in December 2013. The NEB did not approve the application as a settlement but allowed us the option to continue with the application as a contested tolls application, amend the application or terminate the processing of the application. We amended the application with additional information.
November 2014	Following a hearing, the NEB approved the Canadian Mainline's 2015 - 2030 Tolls and Tariff Application (the **NEB 2014 Decision**) which superseded the NEB 2013 Decision. The application reflected components of the LDC Settlement. In 2014, the Canadian Mainline operated under the NEB's decision for the years 2013-2017, which included an approved ROE of 11.5 per cent on deemed common equity of 40 per cent and an incentive mechanism based on total net revenues.

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

Date	Description of development

U.S. Pipelines

Sale of GTN Pipeline, Bison Pipeline and Portland Natural Gas Transmission System (PNGTS) to TC PipeLines, LP (TCLP)	
July 2013	We sold an additional 45 per cent interest in each of Gas Transmission Northwest LLC (**GTN**) and Bison Pipeline LLC (**Bison**) to TCLP for an aggregate purchase price of US$1.05 billion. We continued to hold a 30 per cent direct ownership interest in both pipelines.
October 2014	We closed the sale of our remaining 30 per cent interest in Bison to TCLP for cash proceeds of US$215 million.
April 2015	We closed the sale of our remaining 30 per cent interest in GTN to TCLP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$246 million in cash, the assumption of US$98 million in proportional GTN debt and US $95 million of new Class B units of TCLP.
January 2016	We closed the sale of 49.9 per cent of our total 61.7 per cent interest in PNGTS to TCLP for US$223 million including the assumption of US$35 million of proportional PNGTS debt.
TC Offshore	
December 2015	We entered into an agreement to sell TC Offshore to a third party and expect the sale to close in early 2016. As a result, at December 31, 2015, the related assets and liabilities were classified as held for sale and were recorded at their fair values less costs to sell. This resulted in a pre-tax loss provisions of $125 million recorded in 2015.
Great Lakes	
November 2013	Great Lakes received FERC approval for a rate settlement with its shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from its recourse rate contracts. The settlement included a 17 month moratorium through March 2015 and required us to have new rates in effect by January 1, 2018.
February 2016	We reduced forecasted cash flows from the reporting unit for the next ten years as compared to those utilized in previous impairment tests. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$386 million at December 31, 2015 (2014 – US$243 million).
Northern Border	
January 2013	Northern Border secured a final settlement agreement with its shippers that the FERC approved in December 2012, effective January 2013. The settlement rates for long haul transportation were approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also included a three year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.

Mexican Pipelines

Topolobampo and Mazatlan Pipeline Projects	
First Quarter 2016	Permitting, engineering, and construction activities are advancing as planned for these two northwest Mexico pipelines. The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and a cost of US$1 billion that will deliver gas to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico. The Mazatlan project is a 413 km (257 miles), 24-inch pipeline running from El Oro to Mazatlan within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million. Both projects are supported by 25-year contracts with the CFE and are in their final construction stages with expected in-service dates in late 2016.
Tuxpan-Tula Pipeline	
November 2015	We were awarded the contract to build, own and operate the US$500 million, 36 inch, 250 km (155 miles) Tuxpan-Tula pipeline with a contracted capacity of 886 MMcf/d for 25 years with the CFE. The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to each of those jurisdictions as well as the central region of Mexico. The pipeline will serve new power generating facilities as well as existing power plants that plan to switch from fuel oil to natural gas as their base fuel. Physical construction is expected to begin in 2016 with a planned in-service date in fourth quarter 2017.

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

International Gas Pipelines

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

LNG Pipeline Projects

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

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

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

DEVELOPMENTS IN THE LIQUIDS PIPELINES BUSINESS

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

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

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

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

DEVELOPMENTS IN THE ENERGY BUSINESS

Date	Description of development
Canadian Power	
Alberta Greenhouse Gas Emissions	
June 2015	The Alberta government announced a renewal and change to the SGER in Alberta. Since 2007, under the SGER, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions by 12 per cent below an average intensity baseline and a carbon levy of $15 per tonne is placed on emissions above this target. The changed regulations include an increase in the emissions reductions target to 15 per cent in 2016 and 20 per cent in 2017, along with an increase in the carbon levy to $20 per tonne in 2016 and $30 per tonne in 2017. Starting in 2018, coal-fired generators will pay $30 per tonne of CO_2 on emissions above what Alberta's cleanest natural gas-fired plant would emit to produce an equivalent amount of electricity. While our Sundance and Sheerness PPAs are subject to this regulation, our inventory of carbon offset credits will mitigate some of these increased costs. The remaining compliance costs are expected to be somewhat recovered through increased market pricing but the full extent is not known at this time.
Napanee	
January 2015	We began construction activities on a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late-2017 or early-2018. Production from the facility is fully contracted with the IESO.
Bécancour	
June 2013	Hydro-Québec Distribution (**Hydro-Québec**) notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014. Hydro-Québec had notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013. Under the original agreement, Hydro-Québec had the option to extend the suspension on an annual basis until such time as regional electricity demand levels recover.
December 2013	We entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continued to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended.
May 2014	We received final approval from the Régie de l'énergie for the December 2013 amendment to the original suspension agreement with Hydro-Québec. In addition, Hydro-Québec exercised its option in the amended suspension agreement to extend suspension of all electricity generation to the end of 2017, and requested further suspension of generation to the end of 2018.
August 2015	We executed an agreement with Hydro-Québec to amend Bécancour's electricity supply contract. The amendment allows Hydro-Québec to dispatch up to 570 MW of firm peak winter capacity from the Bécancour facility for a term of 20 years commencing in December 2016. Annual payments received for this new service will be incremental to existing capacity payments earned under the agreement. In October 2015, the Régie de l'énergie approved the amended contract. We continue to receive capacity payments while generation is suspended.
Bruce Power	
April 2013	Bruce Power announced that it had reached an agreement with the Ontario Power Authority to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.
April 2013	Bruce Power returned Bruce A Unit 4 to service after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Bruce A Unit 4 to operate until at least 2021.
March 2014	Cameco Corporation sold its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We maintain an option to increase our Bruce B ownership percentage.

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

U.S. Power

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

Date	Description of development
New York Power Business	
January 2014	Capacity prices in the New York market are established through a series of forward auctions and utilize a demand curve administered price for purposes of setting the monthly spot price. The demand curve, among other inputs, uses assumptions with respect to the expected cost of the most likely peaking generation technology applicable to new entrants to the market. In January 2014, the FERC accepted a new rate for the demand curve that was filed by the New York Independent System Operator as part of its triennial Demand Curve Reset (**DCR**) process. The filing changed the generation technology used in the DCR versus that used during the last reset process for New York City Zone J where Ravenswood operates. Average New York Zone J spot capacity prices were approximately 27 per cent higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014. Average New York Zone J spot capacity prices were approximately 18 per cent lower in 2015 than in 2014. The decrease in spot prices and the impact of hedging activities, resulted in lower realized capacity prices in New York in 2015. The lower spot capacity prices were primarily due to increased available operational supply in New York City's Zone J market. In 2014 we disclosed that the FERC announced a decision affecting future capacity auctions in New England Power Pool (**NEPOOL**) which we thought may potentially improve capacity price conditions in 2018 and beyond. Since the announcement, capacity prices have improved in 2018 and beyond for our assets that are located in NEPOOL.

Natural Gas Storage

April 2014	We sold out interest in the Alaska LNG project to the State of Alaska. The proceeds from the sale provide a full recovery of costs incurred to advance the project since January 1, 2014 including a carrying charge. With this sale, our involvements in developing pipeline system for commercializing the Alaska North Slope natural gas ceases.

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

Business of TransCanada

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

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

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

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

NATURAL GAS PIPELINES BUSINESS

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

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

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

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

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

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

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

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

LIQUIDS PIPELINES BUSINESS

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

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

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

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

REGULATION OF THE NATURAL GAS AND LIQUIDS PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

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

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

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

West Coast LNG – Natural Gas Pipeline Projects

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

Liquids Pipelines

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

Liquids Pipelines Projects

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

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

United States

Natural Gas Pipelines

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

Liquids Pipelines

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

Mexico

Natural Gas Pipelines

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

ENERGY BUSINESS

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

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

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

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

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

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

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

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

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

Power purchased under long-term contracts is as follows:

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

Power sold under long-term contracts is as follows:

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

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

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

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

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

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

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

Assets currently under construction are as follows:

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

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

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

General

EMPLOYEES

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

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

CORPORATE RESTRUCTURING AND BUSINESS TRANSFORMATION

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

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

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

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

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

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

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

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

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

Environmental policies

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

Safety and asset integrity

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

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

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

Social Policies

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

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

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

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

Risk factors

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

Dividends

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

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

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

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

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

Description of capital structure

SHARE CAPITAL

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 702,614,096 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	8,533,405	Series 4 preferred shares
Series 4 preferred shares[2]	5,466,595	Series 3 preferred shares
Series 5 preferred shares[3]	12,714,261	Series 6 preferred shares
Series 6 preferred shares	1,285,739	Series 5 preferred shares
Series 7 preferred shares	24,000,000	Series 8 preferred shares
Series 9 preferred shares[4]	18,000,000	Series 10 preferred shares
Series 11 preferred shares[5]	10,000,000	Series 12 preferred shares

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

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

Common shares

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

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

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

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

First preferred shares

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

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

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

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

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

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

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

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

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

Second preferred shares

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

Credit ratings

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

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

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

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

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

DBRS

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

MOODY'S

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

S&P

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

Market for securities

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

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

COMMON SHARES

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

PREFERRED SHARES

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

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

Directors and officers

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

DIRECTORS

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

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

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

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

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

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

BOARD COMMITTEES

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

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

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

OFFICERS

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

Executive officers

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

Corporate officers

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

CONFLICTS OF INTEREST

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

Serving on other boards

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

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

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

Affiliates

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

Corporate governance

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

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

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

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

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

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

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

Audit committee

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

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

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

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

Siim A. Vanaselja

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

Kevin E. Benson

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

Derek H. Burney

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

John E. Lowe

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

Mary Pat Salomone

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

D. Michael G. Stewart

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

PRE-APPROVAL POLICIES AND PROCEDURES

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

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

EXTERNAL AUDITOR SERVICE FEES

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

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

Legal proceedings and regulatory actions

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

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

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

Transfer agent and registrar

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

Material contracts

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

Interest of experts

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

Additional information

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

Glossary

Units of measure

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

General terms and terms related to our operations

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

Accounting terms

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

Government and regulatory bodies terms

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

Schedule A
Metric conversion table

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

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

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

Schedule B
CHARTER OF THE AUDIT COMMITTEE

1. PURPOSE

The Audit Committee shall assist the Board of Directors (the Board) in overseeing and monitoring, among other things, the:
- Company's financial accounting and reporting process;
- integrity of the financial statements;
- Company's internal control over financial reporting;
- external financial audit process;
- compliance by the Company with legal and regulatory requirements; and
- independence and performance of the Company's internal and external auditors.

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

2. ROLES AND RESPONSBILITIES

I. Appointment of the Company's External Auditor

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

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

II. Oversight in Respect of Financial Disclosure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. Oversight in Respect of Legal and Regulatory Matters

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

IV. Oversight in Respect of Internal Audit

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

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

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

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

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

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

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

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

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

V. Insight in Respect of the External Auditor

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VII. Oversight in Respect of Certain Policies

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

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

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

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

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

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

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

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

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

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

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

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

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

(h) approve the appointment or termination of auditor;

IX. U.S. Stock Plans

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

X. Oversight in Respect of Internal Administration

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

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

XI. Information Security

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

XII. Oversight Function

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

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

3. COMPOSITION OF AUDIT COMMITTEE

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

4. APPOINTMENT OF AUDIT COMMITTEE MEMBERS

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

5. VACANCIES

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

6. AUDIT COMMITTEE CHAIR

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

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

(b) preside over meetings of the Audit Committee;

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

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

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

7. ABSENCE OF AUDIT COMMITTEE CHAIR

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

8. SECRETARY OF AUDIT COMMITTEE

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

9. MEETINGS

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

10. QUORUM

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

11. NOTICE OF MEETINGS

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

12. ATTENDANCE OF COMPANY OFFICERS AND EMPLOYEES AT MEETING

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

13. PROCEDURE, RECORDS AND REPORTING

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

14. REVIEW OF CHARTER AND EVALUATION OF AUDIT COMMITTEE

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

15. OUTSIDE EXPERTS AND ADVISORS

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

16. RELIANCE

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